Canadian Provincial Grid Code Study

Report for

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FOREWORD

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0	Manz, Voges, Fox, Bachert, Wang, Rao, Das, Chmiel, Barbier, MacDowell	March 27, 2021	Final Draft Report
1	Ibid	May 18, 2021	Final report incorporating comments from the Utility Forum and Wind Energy Institute of Canada
2	Ibid	September 2, 2021	Updated final report incorporating 2nd round of comments from the Utility Forum and Wind Energy Institute of Canada.

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Natural Resources Canada (NRCan) has constituted a Utility Forum which brings together all ten Canadian provincial transmission system operators to discuss issues of shared importance specific to the planning and operation of power systems with high penetrations of variable generators (solar, wind). The Utility Forum has budget allocated for field demonstrations, research work or pilot projects in collaboration with equipment manufacturers and provincial utilities. This project is Task 2 of three planned projects.

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1 LIST OF ACRONYMS

A	Ampere (unit of electrical current)
AB	Alberta (Canada)
AEMO	Australia Electricity Market Operator (Australia)
AESO	Alberta Electric System Operator (Canada)
AU	Australia
BA	Balancing Authority
BC	British Columbia (Canada)
BES	Bulk Electric System
BESS	Battery Energy Storage System
BPS	Bulk Power System
CA	California
CAISO	California Independent System Operator (United States)
CCT	Critical Clearing Time
cSCR	Composite Short Circuit Ratio
DB	Dead band
dB	Decibel
DER	Distributed Energy Resources
DG	Distributed Generation
DR	Demand Response
EI	Eastern Interconnect (United States)
ERCOT	Electric Reliability Council of Texas (United States)
ESIG	Energy Systems Integration Group
FERC	Federal Energy Regulatory Commission (United States)
FFR	Fast Frequency Response
FRT	Fault Ride Through
FSM	Frequency Sensitive Mode
GB	Great Britain
GBGFC	Great Britain Grid Forming Converter

GFL	Grid Following
GFM	Grid Forming
GO	Generator Owner
GOP	Generator Operator
GPST	Global Power System Transformation Consortium
H	Inertia constant
HPTF	High Penetration Task Force (ESIG)
HQ	Hydro Quebec (Canada)
HV	High Voltage
HVDC	High Voltage Direct Current
HVRT	High Voltage Ride Through
Hz	Hertz (unit of electrical frequency)
IA	Interconnection Agreement
IBR	Inverter-Based Resource
IE	Ireland (Republic of Ireland)
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent Electric System Operator (of Ontario, Canada)
IRPTF	Inverter-based Resource Performance Task Force (NERC)
IRPWG	Inverter-based Resource Performance Working Group (NERC)
ISO	Independent System Operator
kV	kilovolt (measure of electrical voltage)
LB	Labrador (Canada)
LFSM	Limited Frequency Sensitive Mode
LSE	Load-serving Entity
LV	Low Voltage
LVRT	Low Voltage Ride Through
MB	Manitoba (Canada)
MH	Manitoba Hydro (Canada)

MVA	Mega-volt Ampere (unit of complex power)
MVAr	Mega-volt Ampere Reactive (unit of reactive power)
MW	Mega-watt (unit of real power)
NB	New Brunswick (Canada)
NERC	North American Electric Reliability Corporation (United States)
NG	National Grid
NGESO	National Grid Electric System Operator (Great Britain)
NF	Newfoundland (Canada)
NRCan	Natural Resources Canada
NS	Nova Scotia (Canada)
OF	Over-frequency
ON	Ontario (Canada)
OV	Over-voltage
PE	Prince Edward Island (Canada)
PF	Power Factor
PFreg	Power Factor Regulation
PFR	Primary Frequency Response
PMU	Phasor Measurement Unit
POI	Point of Interconnection
POM	Point of Measurement
POR	Point of Regulation
POTT	Permissive Overreaching Transfer Trip (communications-based distance protection)
PQ	Power Quality
Prat	Rated Power
PSS	Power System Stabilizer
PUTT	Permissive Underreaching Transfer Trip (communications-based distance protection)
PV	Photovoltaic (solar generation)
Q	Reactive Power
Qreg	Reactive Power Regulation

QC	Quebec (Canada)
REG	Regulation (balancing electrical supply and demand to maintain frequency)
RWG	Reliability Working Group (ESIG)
SCR	Short Circuit Ratio
SCRIF	Short Circuit Ratio with Interaction Factor
SIA	System Impact Assessment
SIR	Synchronous Inertial Response
SK	Saskatchewan (Canada)
SM	Synchronous Machine(s)
SPIDERWG	System Performance Impact of Distributed Energy Resource Working Group (NERC)
SPS	Special Protection System
SSCI	Sub-synchronous Control Interaction
SSTI	Sub-synchronous Torsional Interaction
SSR	Sub-synchronous Resonance
THD	Total Harmonic Distortion
TO	Transmission Owner
TOP	Transmission Operator
TP	Transmission Planner
TOV	Transient Over-voltage
TX	Texas
UF	Under-frequency
UFLS	Under-frequency Load Shedding
UK	United Kingdom
UL	Underwriters Laboratories
USA	United States of America
UV	Under-voltage
V	Volts (unit of electrical voltage)
VAR	Volt-amp Reactive
Vref	Voltage Reference

Vreg	Regulated Voltage
VSM0H	Virtual Synchronous Machine with zero inertia
WECC	Western Electricity Coordinating Council
WEICan	Wind Energy Institute of Canada
WF	Wind Farm
WI	Western Interconnect
WPP	Wind Power Plant
WSCR	Weighted Short Circuit Ratio

2 EXECUTIVE SUMMARY

STUDY GOAL: TO LOWER THE BARRIERS TO ENTRY FOR RENEWABLE GROWTH BY RECOMMENDING OPPORTUNITIES TO HARMONIZE GRID CODES ACROSS CANADA

Natural Resources Canada's (NRCan) Utility Forum via The Wind Energy Institute of Canada (WEICan) hired GE Energy Consulting **to recommend opportunities to harmonize grid codes across Canada as a means to lower the barriers to entry for further renewables development.** WEICan is a not-for-profit entity that advances the development of wind energy across Canada through research, testing, innovation and collaboration. As part of this mandate, WEICan acts as facilitator for NRCan's Utility Forum which is a member-driven industry group with representation from all ten Canadian provincial utilities and system operators.

WEICan and NRCan's utility forum established the following goals for this study:

1. **To identify opportunities to harmonize Canadian provincial grid requirements** which lower the barriers to further renewables growth
2. **To leverage global best practices** with respect to managing variable energy and inverter-based resources
3. **To account for the impact of distributed energy** resources and unlock the value of energy storage and
4. **To identifying market and/or rule-based mechanisms** to promote cost effective deployment of essential reliability services

EMERGING GRID CODE ELEMENTS PRESENT THE GREATEST OPPORTUNITY FOR HARMONIZATION ACROSS CANADA

In surveying the grid codes across Canada, we found that codes could generally be categorized into one of two types:

1) **Traditional aspects of grid codes are fairly harmonized across Canada today.** These elements of the grid code cover requirements that have been well-established across the industry:
    - voltage and reactive power support
    - balancing and regulation
    - power quality
    - protection.

    We found that these traditional grid code elements are somewhat harmonized across the provinces today.

2) **Emerging aspects of grid codes are less harmonized across the provinces.** These codes covered requirements that emerged in response to the growth of inverter-based resources (IBRs) such as:
    - frequency support
    - large signal stability and performance during disturbances
    - small signal stability

We found that these requirements are in various stages of deployment across the provinces, largely based on the history and current penetrations of IBR technology. **These requirements and practices continue to evolve in each province as the mix changes and have ample opportunity to be harmonized between provinces.**

INTERNATIONAL GRID CODES ARE ALSO EVOLVING ESPECIALLY REGARDING EMERGING GRID CODE ELEMENTS

The international grid requirements we surveyed are also in various stages of deployment, given each system is in its own transition towards greater levels of IBRs. System operators and policy makers in Australia, Ireland, UK and Texas (US) have more advanced or prescriptive requirements to meet system needs versus Canadian Provinces. This is particularly true for frequency and voltage support, small and large signal stability and performance during disturbances, modeling.

HARMONIZATION OF GRID CODES ACROSS CANADA SHOULD FOCUS ON EMERGING GRID CODE ELEMENTS

Given our review of the grid codes across Canada and a number of international jurisdictions, we provide the following recommendations for harmonizing grid codes across Canada:

General recommendations[1]

- **Requirements should only be as specific as they need to be.** The purpose is to avoid over-designed equipment and reduced efficiency while being specific enough to maintain adequate system reliability.
- **Maintain a common grid code "application guide" to enable comparison of codes across provinces.** The NRCan Utility Forum should create and maintain a common grid code form or "Application Guide" for requirements across Canada in order to track progress on requirements over time and harmonize across the provinces where necessary. A sample data collection form and guideline structure is included with this report (Appendix A) and may be used to maintain the application guide going forward.
- Every resource connected to the Bulk Electric System (BES) should be **equipped with the capability for high-resolution data recording** to sufficiently capture voltage and current waveforms during any fault or large grid disturbance.
- Consider new technologies such as **Grid Forming (GFM) resources** and **battery energy storage** to support growing penetration of IBRs.

Frequency Stability and Support

- Inverter-based resources should have the capability of providing Fast Frequency Response (FFR) and Primary Frequency Response (PFR) with an adjustable droop range and tunable control characteristics.

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[1] Note that the recommendations below should be applied to future installations as commercial inverter technology has matured sufficiently. Requirements for existing generation should be examined individually.

Large signal stability and performance during disturbances

- **Inverters should avoid using protection settings that trip or block output** due to instantaneous frequency excursions or phase-jumps.
- **New inverters should not momentarily block or cease current injection** for disturbances with voltage profiles within the required time-voltage envelope set in the voltage ride-through requirement for grids above a minimum prescribed Composite Short Circuit Level (cSCR) level.
- Existing inverters where **momentary cessation** cannot be eliminated should not be impeded from restoring current injection following a momentary cessation by plant-level ramp rates meant for operational adjustments.
- Inverter voltage **protection should be set based on physical equipment and stability limitations** and should use appropriately filtered voltage input.
- **Inverters should not trip due to PLL loss of synchronism** caused by waveform distortion or phase jumps caused by switching or large disturbances.
- **DC reverse current detection and protection should be coordinated** to avoid tripping for DC reverse currents.
- Collector system design and **ride-through capability** should account for voltage drop and reactive loss/gain across the collector network to appropriately assess compliance with plant-level ride through requirements. Also, **grid codes should clearly state the measurement point (e.g. Point of Interconnection) and measurement quantity (e.g. positive sequence voltage or voltage of a single phase) when specifying ride-through curves.**
- **AC overcurrent, DC and AC overvoltage protection should be explicitly included** in ride-through standards.
- The following weak grid risks and failure modes should be considered when evaluating interconnection of IBRs:
    - Failure to ride-through disturbances
    - Converter control interactions
    - Converter control instability
    - Cycling between converter control modes
    - Steady-state voltage collapse

Small signal stability

- Plant developers and owners should screen plant interconnection design for **TOV, shunt resonance and other high-frequency phenomena** caused by MV-connected shunt compensation, selection and layout of buried collector system cable, transformer saturation and capacitive coupling, etc.
- System operators should use screening criteria to classify **grid strength through metrics of SCR, cSCR, WSCR and SCRIF,** as recommended by the NERC Reliability Guideline to Integrate VER into Weak Power Systems (2017), to determine when EMT modeling is necessary to assess risk of control interaction or stability issues due to weak power grids.

GRID CODES CONTINUE TO PLAY AN INCREASLINGLY IMPORTANT ROLE TO SUPPORT GROWTH OF DISTRIBUTED ENERGY RESOURCES

Distributed generation impacts to the bulk electric system continue to grow in importance in many North American jurisdictions as the impact of the penetration of DER (especially PV solar) increases. This impact may manifest in several ways. This report identifies the many ways that DER impacts the bulk transmission grid, outlines some of the risks and practices to identify and mitigate those risks and makes recommendations, where practical, for codes in Canada to address these issues, including:

- Promote requirements that address **inverter control stability, momentary cessation and tripping of DER** during bulk-grid disturbances
- Regional variability and uncertainty of power output due to the nature of the energy source
- **Promote forecasting methods that properly account for DER growth and impact,** address difficulties due to DER netting out load and utilize the appropriate forecast horizon (day-ahead, hour-ahead, etc.) depending on the technology.
- Ramping and flexibility of bulk generation and controllable load to accommodate increasing variability and uncertainty of distributed PV solar
- **Adopt latest power system protection practices at the T-D interface**, accounting for bi-directional flows, changes in short-circuit behavior, impacts to impedance-based distance protection and islanding detection.
- Promote latest practices for **Appropriate modeling of load** using the latest composite load models representing explicit DER behavior (u-DER and r-DER) should be used in grid analyses.
- Consider **expanded role of hosting capacity analysis** to identify bulk-grid reliability risks.
- Account for **integrated T&D planning and operational practices**
- Account for **policy/market drivers and initiatives for DER deployment** and growth as synchronous generation is being displaced.

LATEST IN-DRAFT AND RECENTLY RELEASED STANDARDS PLAY A ROLE TO SHAPE GRID CODES

There are various standards currently in draft or other recent industry activities that help shape requirements based on latest technology, modeling and planning practices. These latest standards and activities include:

- IEC Technical Committee 8, which focuses on standards for energy systems aspects, including grid integration of renewable energy generation (subcommittee 8A), decentralized electrical energy systems (subcommittee 8B) and network management (subcommittee 8C). Altogether, these subcommittees are tackling standardization needs for various subjects around grid reliability & stability, equipment performance, system operations & forecasting, modeling, contingency assessment and mitigation, compliance testing and DER integration.
- IEEE std P2800 is a new "bridge" standard that focuses on the "Interconnection and Interoperability of Inverter-Based Resources (IBR) Interconnecting with Associated Transmission Electric Power Systems." The Standard is intended to establish the required interconnection capability and performance criteria for inverter-based resources interconnected with transmission and sub-transmission systems. While P2800 is under development, it is likely the final version will specify performance and functional capabilities of IBR, specify function default settings of IBR, specify functional ranges of allowable settings, specify modeling data and measurement data for performance monitoring and validation, and specify required test and verifications (but not their detailed procedures).

- Other recently adopted standards, like IEEE 1547, and recent industry activities led by the North American Electric Reliability Corporation, the Energy Systems Integration Group and the Global Power Systems Transformation Consortium focus on specifying reliability criteria for distributed energy resources, as well as integration of new technologies, such as hybrid power plants with energy storage, grid forming controls and interoperability of all resources and devices.

GRID CODES SHOULD CONSIDER LATEST MODELING CAPABILITIES AND PRACTICES TO EVALUATE GRID NEEDS AND AVAILABILE TECHNOLOGIES

Grid modeling practices continue to evolve as the resource mix diversifies, integrating more variable inverter-based resources that require more detailed and integrated models across many timescales. These models include electromagnetic transients models (EMT), next-generation positive sequence fundamental frequency models and integrated production cost models that account for equipment stability and operations. Also, new modeling methods for short circuit characterization and harmonics (such as the Norton Equivalent current source model) are needed and evolving.

ELECTRICITY MARKETS ARE PLAYING AN INCREASING ROLE TO MAXIMIZING ANCILLARY SERVICES AND REMOVING BARRIERS TO PARTICIPATION OF INVERTER-BASED DISTRUBUTED RESOURCES

The role of electricity markets continues to evolve to incent ancillary grid services from resources to support grid needs for frequency support, balancing and ramping, flexibility, black start and restoration. There are key examples from around the world (such as Texas and Ireland) where these services pay for performance via a dedicated price signal or co-optimized with energy. In the evolving (non-traditional centrally dispatched) grid, inverter-based generation (most often solar and wind generation as well as battery storage) are increasingly able to provide reliability services. This is a relatively new entrant as a provider of ancillary services and current best practice is changing rapidly. While inverter-based resources can provide a number of different reserves, there remains number of barriers to their participation. In some places around the world, DERs are also being allowed to participate in ancillary markets, if their performance meets minimum requirements. New policy regulations, such as FERC 2222, are now making provisions to pay aggregated DER to provide ancillary services.

AS CANADA FURTHER DECARBONIZES, SOME PROVINCES WILL REQUIRE RECORD LEVELS OF VARIABLE RENEWABLES

In late 2020, the Canadian Minister of Environment and Climate Change proposed legislation to transition Canada to a net-zero emissions economy by 2050 with legally binding interim targets starting in 2030. While decarbonization of the electric sector will likely be minor compared to decarbonization of end-use sectors like industry, electrification will likely be one of the top decarbonization pathways. Electrification will only have a carbon benefit if the electric mix supports it.

Canada’s electric generation mix is already approximately 80% carbon-free. However, if you drill down into the electric mix of each province, you will see that the Maritimes (NS, NB) and prairies (SK, AB) are much more carbon intensive. New transmission options from hydro-rich provinces can also help but could it be enough to close the fossil gap? **Decarbonization of these provinces will likely require record amounts of wind and solar energy.**

HOLISTIC INTEGRATED PLANNING WILL BE REQUIRED TO PLAN FOR NEW LEVELS OF VARIABLE RENEWABLES ACROSS CANADA

Planning for new levels of wind and solar energy challenges system operators in three ways:

1. An *operations* transformation: **constant-fuel to weather-dependent fuel.**
2. An *economics* transformation: **fossil-based energy prices to zero-cost energy prices.**
3. A *physics* challenge: **synchronous machines to inverter-based resources.**

Planning for all three of these transformations requires integrating across the planning methods for each. GE Energy Consulting recommends an integrated approach that iterates through the following planning steps:

Step 1: Formulate baseline scenarios that assume a future resource mix to meet carbon goals

Step 2: Optimize these scenarios by identifying and mitigate risks through the following iterative approach:

(a): Production dispatch simulation & screening to **identify non-peak intervals of risk.** (e.g. peak net load, peak ramping, low synchronous unit headroom)

(b): Network simulations to identify reliability needs and mitigations. There are most commonly six areas of network risk to assess: thermal limits, frequency stability, voltage stability, weak grid, transient stability, and small signal stability. Through analysis of these risk areas, we can then identify mitigations that we will then incorporate into our optimized scenarios.

(c): Adequacy simulations to identify additional resource needs. These simulations are a probabilistic assessment that determines where there are sufficient resources (generation planning reserves) to meet reliability metrics such as loss of load expectation (LOLE), expected unserved energy (EUE). This analysis is performed to assess if sufficient capacity is available to meet peak conditions and sufficient resources are available during all hours during the year. (d): Reflect constraints and incorporate mitigations into optimized system scenarios & repeat process

Canadian provinces can use holistic planning to prepare for deep levels of decarbonization where the operations, economics, and physics of the system are all transforming at the same time. The traditional linear planning approach is no longer sufficient, and we suggest a new iterative and integrated approach with **tighter coupling between the economic and technical simulation environments is needed** with results of each class of simulation impacting and advising changes in the other.

1 RÉSUMÉ

OBJECTIF DE L'ÉTUDE : DIMINUER LES OBSTACLES POUR L'ACCES DES ENERGIES RENOUVELABLES AU RÉSEAU CANADIEN EN RECOMMANDANT DES OPPORTUNITÉS D'HARMONISATION DES CODES DE RÉSEAU

L'Institut de l'Energie Eolienne du Canada (WEICan), en association avec le Forum des Services Publics des Ressources Naturelles du Canada (RNCan), a embauché GE Energy Consulting pour recommander des possibilités d'harmonisation des Codes de Réseau au Canada afin de réduire les obstacles au développement des énergies renouvelables. WEICan est une entité à but non lucratif qui fait progresser le développement de l'énergie éolienne à travers le Canada grâce à la recherche, aux essais, à l'innovation et à la collaboration. Dans le cadre de ce mandat, WEICan agit à titre de facilitateur pour le Forum des Services Publics de RNCan, un groupe industriel dirigé par ses membres et représentant les dix services publics et exploitants de réseau des provinces canadiennes.

WEICan et le Forum des Services Publics de RNCan ont établi les objectifs suivants pour cette étude :

1. Identifier les possibilités d'harmoniser les exigences du réseau canadien, ce qui abaisse les obstacles à la poursuite de la croissance des énergies renouvelables

2. Tirer parti des meilleures pratiques mondiales en matière de gestion des énergies variables et des ressources basées sur les onduleurs

3. Tenir compte de l'impact des ressources énergétiques distribuées et débloquer la valeur du stockage d'énergie et

4. Identifier les mécanismes fondés sur le marché et / ou les règles pour promouvoir un déploiement rentable des services essentiels de fiabilité

LES PARTIES EMERGENTES DU CODE DE RÉSEAU PRÉSENTENT LA PLUS GRANDE OPPORTUNITÉ D'HARMONISATION À TRAVERS LE CANADA

En examinant les codes de réseau à travers le Canada, nous avons constaté que les codes pouvaient généralement être classés en deux types :

1) Les codes de réseau traditionnels sont assez harmonisés à travers le Canada aujourd'hui. Ces éléments du code de réseau couvrent des exigences bien établies dans l'industrie :
    - Prise en charge de la tension et de la puissance réactive
    - Équilibre et régulation
    - Qualité de l'électricité
    - Protection.

    Nous avons constaté que ces éléments de code de réseau traditionnels sont assez bien harmonisés entre les provinces aujourd'hui.

2) Les codes de réseau des énergies émergentes sont moins harmonisés dans les provinces. Ces codes couvraient les exigences qui ont émergé en réponse à la croissance des ressources basées sur les onduleurs (IBR) telles que :
    - Gestion de la fréquence

- Stabilité sur grandes perturbations et performances pendant les perturbations
- Stabilité sur faibles perturbations

Nous avons constaté que ces exigences en sont à divers stades de déploiement dans les provinces, en grande partie en fonction de l'histoire et des pénétrations actuelles de la technologie IBR. Ces exigences et pratiques continuent d'évoluer dans chaque province au fur et à mesure que la composition des ressources change et ont amplement l'occasion d'être harmonisées entre les provinces.

LES CODES DE RESEAUX INTERNATIONAUX ÉVOLUENT AUSSI SURTOUT EN CE QUI CONCERNE LES ÉLÉMENTS ÉMERGENTS

Les réseaux internationaux que nous avons étudiés sont également à divers stades de déploiement, étant donné que chaque système est dans sa propre transition vers des niveaux plus élevés de IBR. Les opérateurs de système et les décideurs politiques en Australie, en Irlande, au Royaume-Uni et au Texas (États-Unis) ont des exigences plus avancées ou normatives pour répondre aux besoins du système que le Canada. Cela est particulièrement vrai pour le support de fréquence et de tension, la stabilité des petits et des grands signaux et les performances pendant les perturbations, la modélisation.

L'HARMONISATION DES CODES DE RÉSEAU À TRAVERS LE CANADA DEVRAIT SE CONCENTRER SUR LES ÉLÉMENTS ÉMERGENTS

Compte tenu de notre examen des codes de réseau au Canada et dans un certain nombre de juridictions internationales, nous formulons les recommandations suivantes pour l'harmonisation des codes de réseau à travers le Canada :

Recommandations générales

- Les exigences doivent être aussi spécifiques que nécessaire. Le but est d'éviter un équipement surdimensionné ou une efficacité réduite tout en étant suffisamment spécifique pour maintenir une fiabilité adéquate du système.
- Tenir à jour un « guide d’application » commun pour permettre la comparaison des codes entre les provinces. Le Forum des Services Publics de RNCan devrait créer et tenir à jour un formulaire de code de réseau commun ou un « guide de demande » pour les exigences à travers le Canada afin de suivre les progrès des exigences au fil du temps et de les harmoniser entre les provinces le cas échéant. Un exemple de formulaire de collecte de données et un guide de lignes directrices sont inclus avec ce rapport et peuvent être utilisé pour maintenir le guide d'application à l'avenir.
- Chaque ressource doit être équipée d’enregistreurs de données à haute résolution pour capturer suffisamment les formes d'onde de tension et de courant pendant tout défaut ou grande perturbation du réseau.
- Envisager de nouvelles technologies telles que les ressources de formation de réseau (GFM) et le stockage d'énergie par batterie pour soutenir la pénétration croissante des IBR.

Stabilité et support de fréquence

Les ressources basées sur les onduleurs doivent avoir la capacité de fournir une réponse en fréquence rapide (FFR) et une réponse primaire en fréquence (PFR) avec une plage de statisme réglable et des caractéristiques de commande ajustables.

Stabilité sur grande perturbations et performances pendant les perturbations

- Les onduleurs doivent éviter d'utiliser des paramètres de protection qui déclenchent ou bloquent la production d’énergie en raison d'excursions de fréquence instantanées ou de sauts de phase.
- Les nouveaux onduleurs ne doivent pas momentanément bloquer ou interrompre l'injection de courant pour les perturbations dont les profils de tension se situent dans l'enveloppe temps-tension requise et définie dans l'exigence de passage de creux de tension pour les réseaux au-dessus d'un niveau de cSCR minimum prescrit.
- Les onduleurs existants pour lesquels l'arrêt momentané ne peut être éliminé ne doivent pas être empêchés de rétablir l'injection de courant suite à un arrêt par des taux de variations trop importants au niveau de l'installation, destinés à des ajustements opérationnels.
- La protection de tension de l'onduleur doit être définie en fonction de l'équipement physique et des limitations de stabilité et doit utiliser une entrée de tension correctement filtrée.
- Les onduleurs ne doivent pas se déclencher en raison d'une perte de synchronisme PLL causée par une distorsion de la forme d'onde ou des sauts de phase provoqués par une commutation ou des perturbations importantes.
- La détection et la protection de courant inverse CC doivent être coordonnées pour éviter le déclenchement par courants inverses CC.
- La conception de l’évacuation d’énergie et la capacité de soutenir une perte réseau doivent tenir compte de la chute de tension et de la perte ou du gain de puissance réactive à travers cette évacuation pour évaluer de manière appropriée la conformité avec les exigences de conformité au niveau de la centrale complète. En outre, les codes de réseau doivent indiquer clairement les points de mesure (par exemple, le point d'interconnexion) et les signaux mesurés (par exemple, la tension de séquence directe d'une phase monophasée) lors de la spécification des courbes de défauts.
- Les protections contre les surintensités CA et contre les surtensions CC et CA doivent être explicitement incluses dans les normes pour les conformités aux courbes de défauts.

Stabilité sur faible perturbations

- Pour l’interconnexion de la centrale, les fabricants et les propriétaires d'installations doivent prendre en compte les TOV, les résonances et autres phénomènes haute fréquence causés par la connexion de compensateurs shunts connectés à la MT, la sélection et la disposition des câbles du système d’évacuation d’énergie qui peut être enterré, la saturation du transformateur et le couplage capacitif, etc…
- Utiliser des critères de sélection pour classifier la force du réseau par SCR, cSCR, WSCR et SCRIF, comme recommandé par le guide de fiabilité NERC pour intégrer VER dans les réseaux faibles (2017), afin de déterminer quand la modélisation EMT est nécessaire pour évaluer le risque d'interaction du contrôle ou de problèmes de stabilité dus à la faiblesse des réseaux électriques.
- Les risques des réseaux faibles et les modes de défaillance suivants doivent être pris en compte lors de l'évaluation de l'interconnexion des IBR :

- Défaut de résister aux perturbations temporaires
- Interactions du contrôleur du convertisseur
- Instabilité du contrôleur du convertisseur
- Echanges entre les modes de contrôle du convertisseur
- Effondrement de la tension en régime permanent

LES CODES DE RÉSEAU CONTINUENT À JOUER UN RÔLE DE PLUS EN PLUS IMPORTANT POUR SOUTENIR LA CROISSANCE DES RESSOURCES ÉNERGÉTIQUES DISTRIBUÉES

Les impacts de la production décentralisée sur le système électrique global continuent de gagner en importance dans de nombreuses juridictions nord-américaines à mesure que l'impact de la pénétration du DER (en particulier l'énergie solaire photovoltaïque) augmente. Cet impact peut se manifester de plusieurs manières. Ce rapport identifie les nombreuses façons dont le DER influe sur le réseau de transport global, décrit certains des risques et des pratiques pour identifier et atténuer ces risques et formule des recommandations, lorsque cela est possible, pour que les codes au Canada abordent ces problèmes, notamment :

- Promouvoir les exigences relatives à la stabilité du contrôle des onduleurs, à l'arrêt momentané et au déclenchement du DER lors de perturbations du réseau
- Variabilité régionale et incertitude de la production d'électricité en raison de la nature de l'approvisionnement en combustible
- Promouvoir des méthodes de prévision qui tiennent correctement compte de la croissance et de l'impact du DER et résoudre les difficultés de maillage de charge du DER
- Variation et flexibilité de la production et de la charge contrôlable pour s'adapter à la variabilité et à l'incertitude croissantes de l'énergie solaire PV distribuée
- Adopter les dernières pratiques de protection du système d'alimentation à l'interface T-D, en tenant compte des flux bidirectionnels, des changements de niveau de court-circuit, des impacts sur la protection de distance basée sur l'impédance et la détection de l'îlotage.
- Promouvoir les dernières pratiques en matière de modélisation appropriée de la charge. Les derniers modèles de charge composites représentant un comportement DER explicite (u-DER et r-DER) doivent être utilisés dans les analyses de grille.
- Envisager un rôle élargi de l'analyse de la capacité d'absorption pour identifier les risques de fiabilité du réseau.
- Tenir compte de la planification intégrée du T&D et des pratiques opérationnelles
- Tenir compte des paramètres politiques / du marché et des initiatives pour le déploiement et la croissance du DER à mesure que la production synchrone est effacée.

LES DERNIÈRES NORMES EN ÉBAUCHE ET CELLES RÉCEMMENT PUBLIÉES JOUENT UN RÔLE POUR FAÇONNER LES CODES DE RESEAUX

Il existe diverses normes actuellement en cours d'élaboration ou d'autres activités récentes de l'industrie qui aident à façonner les exigences en fonction des dernières technologies, de la modélisation et des pratiques de planification. Ces dernières normes et activités comprennent :

- Comité technique 8 de la CEI, qui se concentre sur les normes relatives aux aspects des systèmes énergétiques, y compris l'intégration au réseau de la production d'énergie renouvelable (sous-comité 8A), les systèmes d'énergie électrique décentralisés (sous-comité

8B) et la gestion du réseau (sous-comité 8C). Ensemble, ces sous-comités abordent les besoins de normalisation pour divers sujets liés à la fiabilité et à la stabilité du réseau, aux performances des équipements, à l'exploitation et aux prévisions du système, à la modélisation, à l'évaluation des plans d'urgence, aux tests de conformité et à l'intégration DER.

- IEEE std P2800 est une nouvelle norme de « jonction » qui se concentre sur « l'interconnexion et l'interopérabilité des ressources basées sur les onduleurs (IBR) interconnectés avec les systèmes de transport d'électricité associés ». La norme vise à établir la capacité d'interconnexion requise et les critères de performance pour les ressources basées sur des onduleurs interconnectés avec des systèmes de transmission et de sous-transmission. Alors que le P2800 est en cours de développement, il est probable que la version finale spécifiera les performances et les capacités fonctionnelles de l'IBR, spécifiera les paramètres de fonction par défaut de l'IBR, spécifiera les plages fonctionnelles des paramètres autorisés, spécifiera les données de modélisation et les données de mesure pour le suivi et la validation des performances, et spécifiera les exigences requises, les tests et vérifications (mais pas leurs procédures détaillées).
- D'autres normes récemment adoptées, comme IEEE 1547, et des activités industrielles récentes menées par la North American Electric Reliability Corporation, le Energy Systems Integration Group et le Global Power Systems Transformation Consortium se concentrent sur la spécification de critères de fiabilité pour les ressources énergétiques distribuées, ainsi que sur l'intégration de ces nouvelles technologies, telles que les centrales électriques hybrides avec stockage d'énergie, le contrôle des réseaux et l'interopérabilité de toutes les ressources et appareils.

LES CODES DE RÉSEAU DOIVENT CONSIDÉRER LES DERNIÈRES CAPACITÉS ET PRATIQUES DE MODÉLISATION POUR ÉVALUER LES BESOINS DU RÉSEAU ET LES TECHNOLOGIES DISPONIBLES

Les pratiques de modélisation du réseau continuent d'évoluer à mesure que la combinaison de ressources se diversifie, intégrant des ressources basées sur des onduleurs plus variables qui nécessitent des modèles plus détaillés et intégrés sur de nombreuses échelles de temps. Ces modèles comprennent des modèles de transitoires électromagnétiques (EMT), des modèles de fréquence fondamentale à séquence positive de nouvelle génération et des modèles de coûts de production intégrés qui tiennent compte de la stabilité et du fonctionnement des équipements. De plus, de nouvelles méthodes de modélisation pour la caractérisation des courts-circuits et les harmoniques (comme le modèle de source de courant Norton Equivalent) sont nécessaires et évoluent.

LES MARCHÉS DE L'ÉLECTRICITÉ JOUENT UN RÔLE DE PLUS EN PLUS IMPORTANT POUR MAXIMISER LES SERVICES AUXILIAIRES ET ÉLIMINER LES OBSTACLES À LA PARTICIPATION DES RESSOURCES DISTRUBUÉES À BASE D'ONDULEUR

Le rôle des marchés de l'électricité continue d'évoluer pour inciter les services auxiliaires des ressources pour répondre aux besoins du réseau en matière de support de fréquence, d'équilibrage et de montée en puissance, de flexibilité, de démarrage dans le noir et de restauration. Il y a des exemples clefs du monde entier (comme le Texas et l'Irlande) où ces services paient pour la performance via un marché de prix dédié ou co-optimisés. Dans les réseaux en évolution (non traditionnel à répartition centralisée), la production par onduleur (le plus souvent la production solaire et éolienne ainsi que le stockage sur batterie) est de plus en plus en mesure de fournir des services de fiabilité. Il s'agit d'un nouvel entrant en tant que fournisseur de services auxiliaires et les meilleures pratiques actuelles évoluent rapidement. Bien que les ressources basées sur les onduleurs puissent fournir un certain nombre de capacités de réserves différentes, il reste un certain nombre d'obstacles à leur participation. Dans certaines régions du monde, les DER sont également autorisés à participer à des marchés auxiliaires, si leurs performances satisfont aux exigences minimales. De nouvelles règles de politique, telles que la FERC 2222, prévoient maintenant de payer le DER pour fournir des services auxiliaires.

À MESURE QUE LE CANADA SE DECARBONNISERA, LES RESEAUX DE PRODUCTION MARITIMES ET TERRESTRES EXIGERONT DES NIVEAUX RECORDS D'ENERGIES RENOUVELABLES

À la fin de 2020, le ministre canadien de l'Environnement et du Changement climatique a proposé une loi pour faire passer le Canada à une économie à émissions nettes nulles d'ici 2050 avec des objectifs provisoires juridiquement contraignants à compter de 2030. Bien que la décarbonisation du secteur électrique sera probablement mineure par rapport à la décarbonisation globale de secteurs comme l'industrie, la part électrique sera probablement l'une des principales voies de décarbonisation. Cette part électrique n'aura un avantage « carbone » que si le mixage électrique la soutient et soit compatible.

Le mixage de production électrique du Canada est déjà à environ 80% sans carbone. Cependant, si vous explorez le mixage électrique de chaque province, vous verrez que les productions Maritimes (NS, NB) et les productions Terrestres (SK, AB) sont beaucoup plus carbonées. De nouvelles options de transfert de provinces riches en hydraulique peuvent également aider, mais cela pourrait-il suffire à combler le fossé fossile ? **La décarbonisation des productions Terrestres et Maritimes nécessitera probablement des quantités records d'énergie éolienne et solaire.**

UNE PLANIFICATION INTÉGRÉE HOLISTIQUE SERA NÉCESSAIRE POUR PLANIFIER DE NOUVEAUX NIVEAUX D'ENERGIES RENOUVELABLES VARIABLES À TRAVERS LE CANADA

La planification de nouveaux niveaux d'énergie éolienne et solaire met au défi les opérateurs de système de trois manières :

1) Une transformation opérationnelle : énergie disponible de manière permanente en énergie dépendant des conditions météorologiques.
2) Une transformation économique : des prix de l'énergie fossile vers des prix de l'énergie à coût nul.
3) Un défi de physique : transition de machines synchrones aux ressources basées sur des onduleurs.

La planification de ces trois transformations nécessite l'intégration des méthodes de planification de chacune. GE Energy Consulting recommande une approche intégrée qui répète les étapes de planification suivantes :

Étape 1 : Formuler des scénarios de référence qui supposent une future combinaison de ressources pour atteindre les objectifs de décarbonisation

Étape 2 : Optimiser ces scénarios en identifiant et en atténuant les risques grâce à l'approche itérative suivante :

a) Simulation et criblage de la répartition de la production pour identifier les intervalles de risque non maximaux. (Par exemple, charge nette de pointe, rampe de pointe, faible niveau de présence des unités synchrones.)
b) Simulations de réseau pour identifier les besoins de fiabilité et les mesures d'atténuation. Il y a le plus souvent six domaines de risque de réseau à évaluer : les limites thermiques, la stabilité de fréquence, la stabilité de la tension, la faiblesse du réseau, la stabilité sur défaut transitoires larges et la stabilité sur petites perturbations. Grâce à l'analyse de ces zones de risque, nous pouvons ensuite identifier les atténuations que nous intégrerons ensuite dans nos scénarios optimisés.
c) Suffisamment de simulations pour identifier les besoins en ressources supplémentaires
d) Refléter les contraintes et incorporer des plans de replis dans des scénarios optimisés et répéter le processus

Les provinces canadiennes peuvent utiliser une planification holistique pour se préparer à des changements importants de décarbonisation où les opérations, l'économie et la physique du système se transforment toutes en même temps. L'approche de planification linéaire traditionnelle n'est plus suffisante et nous suggérons qu'une nouvelle approche itérative et intégrée avec un couplage plus étroit entre les environnements de simulation économique et technique est nécessaire, les résultats de chaque catégorie de simulation ayant un impact les uns sur les autres.

3 REVIEW AND SUMMARY OF CANADIAN PROVINCIAL GRID CODES

An in-depth review has been conducted of all Canadian provincial grid codes by GE Energy Consulting. This review accounts for the case where the province of Newfoundland and Labrador consists of two interconnected but distinct electrical grids, one on the island of Newfoundland and the other in Labrador. Some aspects of the grid code differ between the two. This review primarily focuses on transmission system considerations in addition to distribution-level considerations that could affect the bulk electrical system, such as fault ride-through. An examination of the existing interconnection requirements of energy storage technologies was included in this review. The technical aspects listed below will be analyzed both in the broader context of NERC requirements and more specific regional balancing area requirements as applicable.

The technical aspects of the codes that will be reviewed, compared and commented upon include:

- Momentary Cessation
- Phase jump immunity including phase-locked loop ride-through.
- Capability Curve
- Active Power-Frequency Controls
- Fast Frequency response
- Reactive Power-Voltage control
- Reactive Current-Voltage control
- Reactive Power at no Active Power Output
- Inverter current injection during faults
- Return to Service Following Tripping
- Balancing including ancillary services such as AGC (automatic generation control)
- Monitoring and data reporting requirements such as data points and update intervals
- Operation in low short-circuit ratio (weak) systems
- Fault ride through capability including low/high voltage and low/high frequencies and reactive power requirements during faults (including a comparison with US States)
- Grid forming capability and performance
- Anti-islanding protection and island mode operation
- System restoration and black start
- Protection settings including overvoltage ride-through
- Power quality
- Where applicable, generation forecast requirements, measured meteorological data reporting
- Battery energy storage – behavior during under frequency load shedding
- Power system damping and small signal stability
- Sub-synchronous resonance (SSR) and sub-synchronous control interaction (SSCI)
- Control stability, control interactions and weak grid connection
- Modeling requirements for various timeframes and applications

This review encompasses all ten (10) Canadian provinces and has a technical focus on the above list of subjects. It covers transmission system codes and requirements, including special requirements, such as the case where Nova Scotia has a single point of connection to the continental grid and may operate islanded.

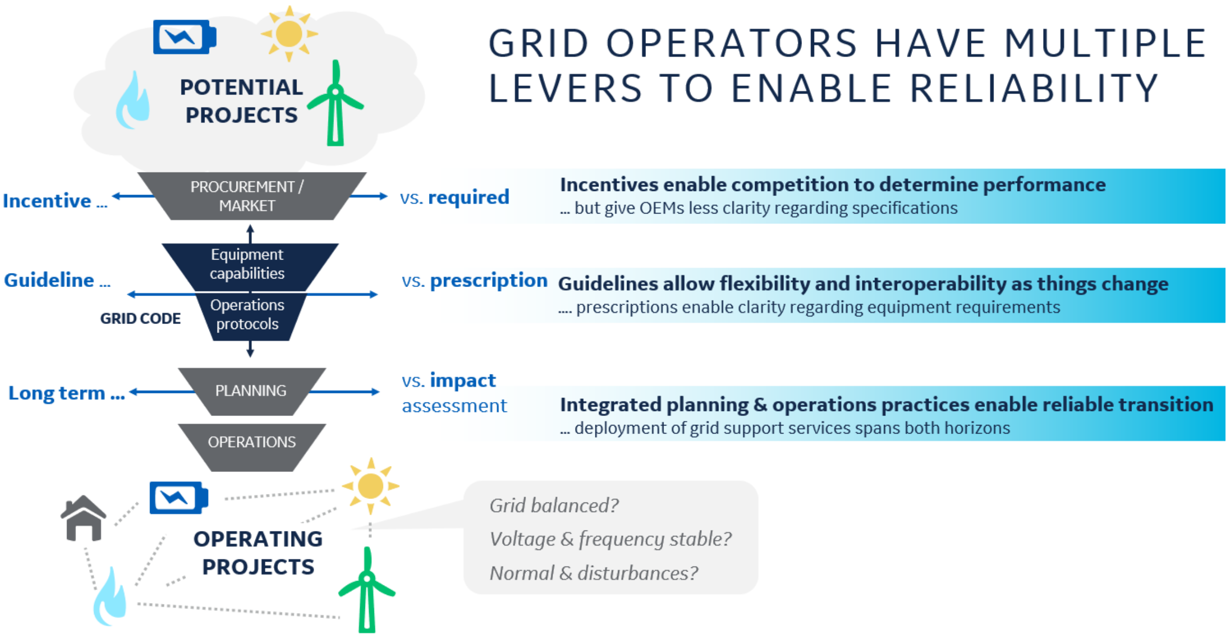


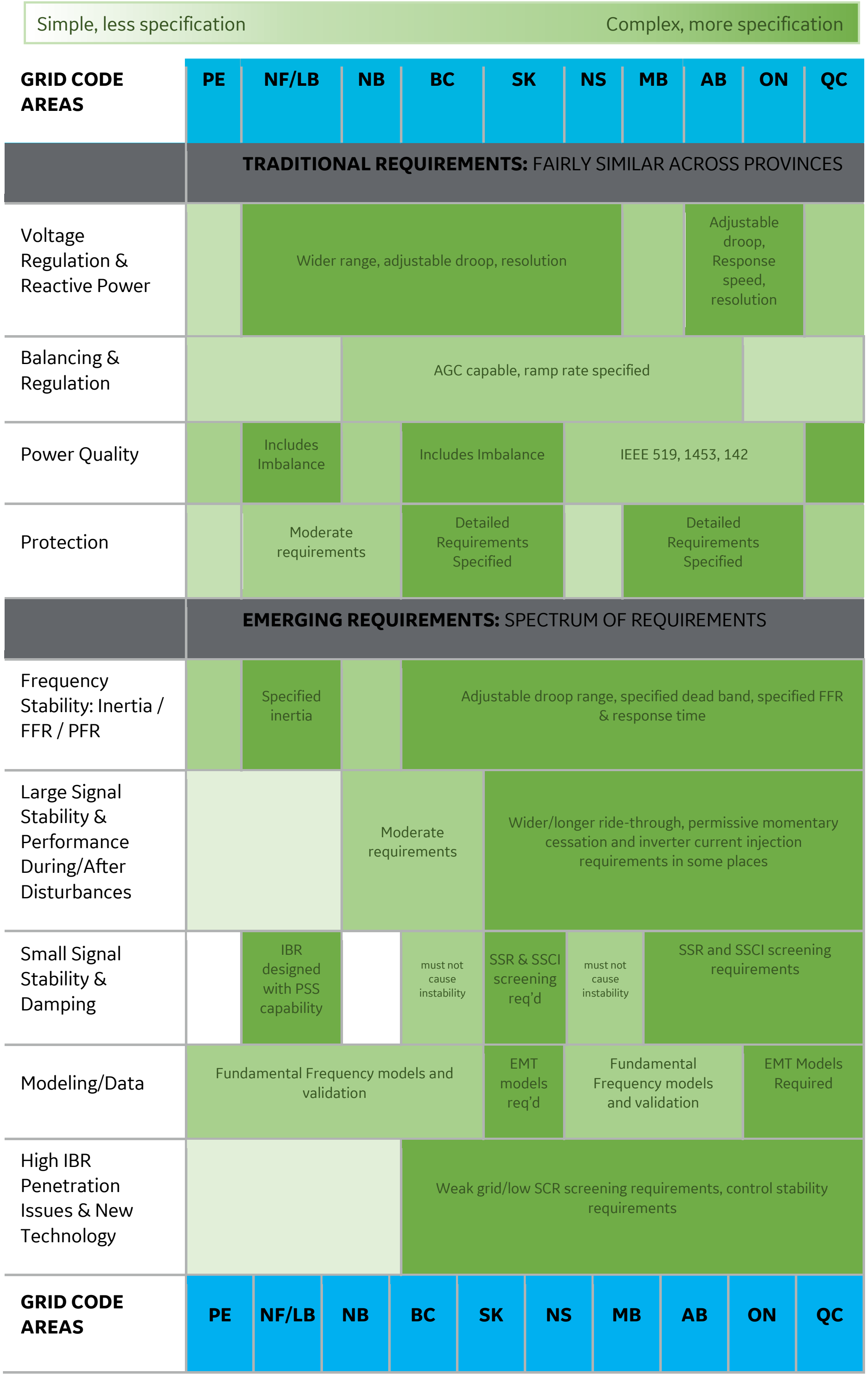
Figure 1: Levers for Grid Reliability

There are various levers that grid operators may adjust to enable grid reliability. Grid codes, interconnection requirements and certain energy trading mechanisms (ancillary services markets or tariffs) play a crucial role to define performance needs of the grid and unlock the capabilities of equipment. These aspects are called out in Figure 1 and include mechanisms for procurement and markets, Grid Code requirements to define equipment capabilities and operational protocols as well as defining planning and operational practices and assessments.

Grid operators use these levers in different ways to incentivize or require a minimum level of performance from all grid assets to meet grid needs and reduce stability and operational risk. This report will outline the benefits and tradeoffs to each aspect of developing requirements, codes and standards as system needs and technologies rapidly evolve. Incentives, such as ancillary services market mechanisms to support voltage and frequency, balancing, ramping, flexibility and grid resiliency are an efficient means to pay for preferred performance. These incentives enable competition to determine preferred performance but often lack the clarity or specificity to support system needs on their own. Codes, interconnection requirements and reliability guidelines are positioned to address specific performance needs of the grid by specifying capabilities and behavior from resources and grid-connected equipment, controls, automation software and communications functionality, as well as planning and operating practices that promote coordinated interoperability of all aspects of the power system.

Table 1 shows a summary and comparison of grid code requirements across all Canadian provinces. It weighs the relative complexity and specificity of requirements across all grid codes, with darker green indicating more detailed or prescribed performance and lighter green indicating simpler or generalized requirements.

Table 1: Comparison of Requirements in Canada



Simple, less specification — Complex, more specification

GRID CODE AREAS	PE	NF/LB	NB	BC	SK	NS	MB	AB	ON	QC
	TRADITIONAL REQUIREMENTS: FAIRLY SIMILAR ACROSS PROVINCES									
Voltage Regulation & Reactive Power		Wider range, adjustable droop, resolution						Adjustable droop, Response speed, resolution		
Balancing & Regulation			AGC capable, ramp rate specified							
Power Quality		Includes Imbalance		Includes Imbalance		IEEE 519, 1453, 142				
Protection		Moderate requirements		Detailed Requirements Specified			Detailed Requirements Specified			
	EMERGING REQUIREMENTS: SPECTRUM OF REQUIREMENTS									
Frequency Stability: Inertia / FFR / PFR		Specified inertia		Adjustable droop range, specified dead band, specified FFR & response time						
Large Signal Stability & Performance During/After Disturbances			Moderate requirements		Wider/longer ride-through, permissive momentary cessation and inverter current injection requirements in some places					
Small Signal Stability & Damping		IBR designed with PSS capability		must not cause instability	SSR & SSCI screening req'd	must not cause instability	SSR and SSCI screening requirements			
Modeling/Data	Fundamental Frequency models and validation				EMT models req'd	Fundamental Frequency models and validation			EMT Models Required	
High IBR Penetration Issues & New Technology				Weak grid/low SCR screening requirements, control stability requirements						
GRID CODE AREAS	PE	NF/LB	NB	BC	SK	NS	MB	AB	ON	QC

Each category of requirements listed in Table 1 is broken out and summarized below in slightly more detail. Extensive research has been performed on all provincial grid code requirements across Canada based on publicly available documents in English. These requirements have been compared regarding their specificity, range and applicability to all resources. A minimum subjective requirement has also been reported in the tables below to indicate a minimum level of system support, where requirements have been specified. The tables below capture the aspects of the code requirements that are specified in each province. There are also many aspects that are unspecified throughout the codes. If a province is not listed in the tables below, there is no specified requirement.

3.1 Voltage Regulation & Reactive Power

Voltage regulation and reactive power requirements are fairly consistent across Canada. A power factor requirement of +0.85 or +0.90 to -0.95 is common to synchronous generation most provinces (such as the example shown for Manitoba in Figure 3), while ±0.95pf is common in Quebec, Ontario, Saskatchewan (for wind generation), British Columbia and Nova Scotia (for wind & solar generation) and Prince Edward Island. In all provinces, a portion of the reactive power must be dynamic. This portion widely varies between provinces. In Alberta, Ontario and Quebec, reactive power requirements are specified above a minimum active power output. In Saskatchewan, full reactive power is required above 10% rated power, per Figure 2. Provision of reactive power during zero active power output is allowed in Ontario and Saskatchewan. Reactive capability curves for Hydro Quebec are found in Figure 4 and Figure 5.

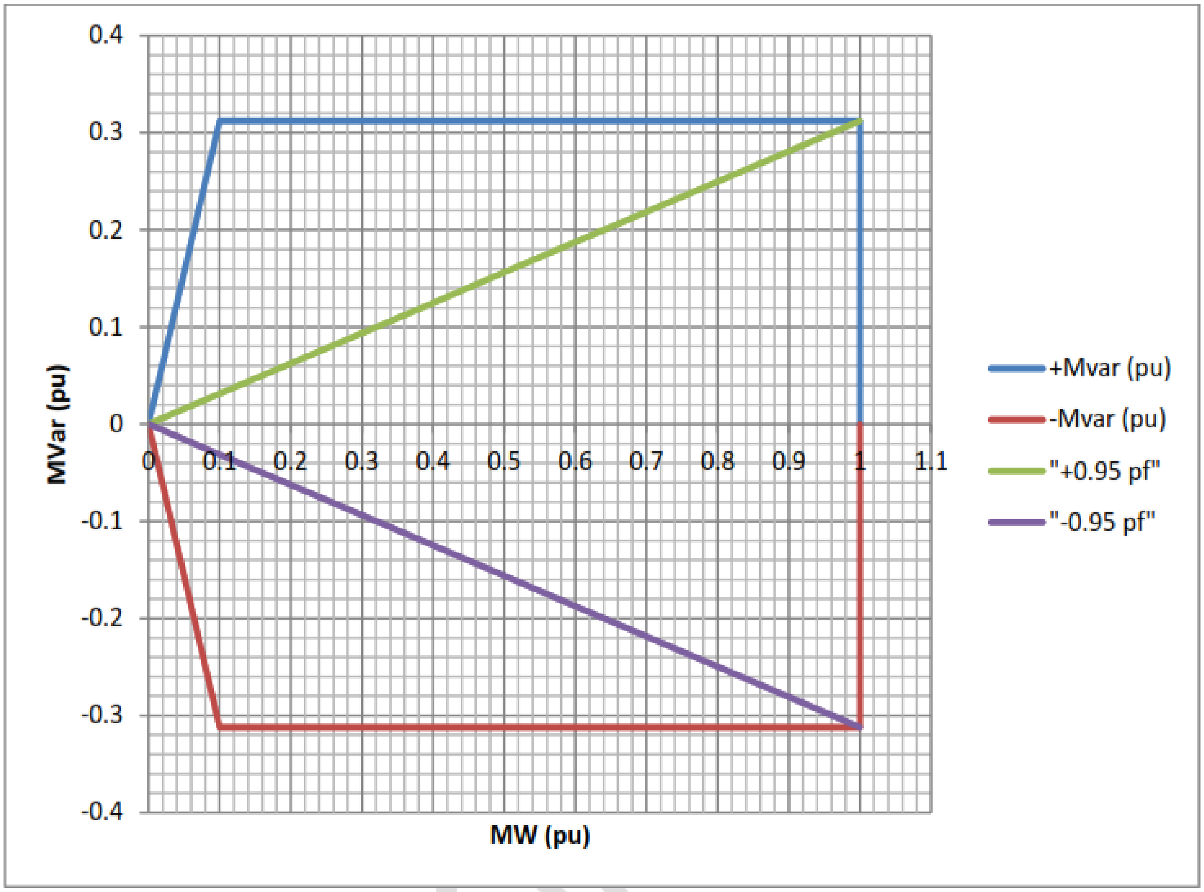


Figure 2: Saskatchewan Reactive Capability

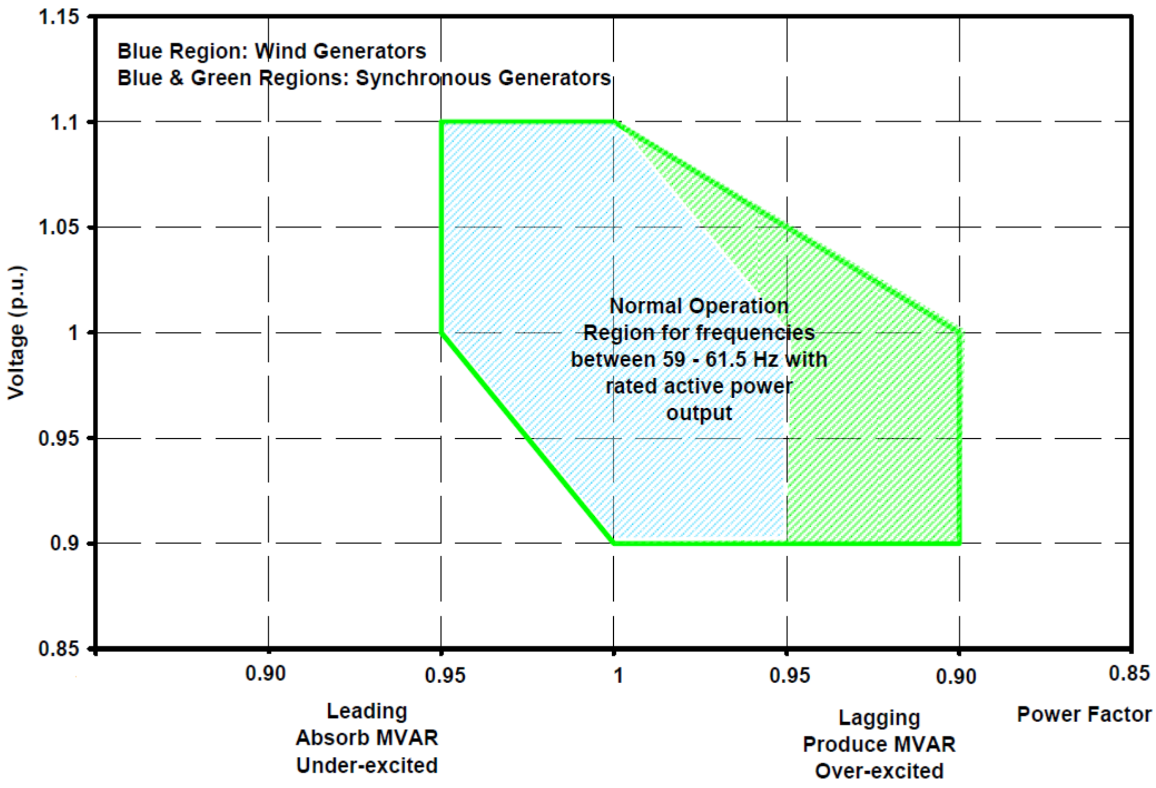


Figure 3: Minimum Reactive Capability Requirements for Generators in Manitoba

Closed-loop voltage regulation is required across all provinces, either explicitly in grid codes or via the NERC VAR-001 and -002 requirements. Continuous voltage regulation is specified in Nova Scotia, New Brunswick and Prince Edward Island codes. ±5% voltage range is specified in Alberta, Ontario and Manitoba, ±10% voltage range is specified in Quebec, Saskatchewan, Newfoundland and Labrador, while +10% to -20% voltage range is specified in British Columbia.

Droop control settings are required to be adjustable in Ontario, adjustable in the range of 0-10% in Quebec, Newfoundland and Saskatchewan and in the range of 0-60% in Nova Scotia. Regulation accuracy is required within ±0.5% in Alberta, Ontario and Nova Scotia and ±0.1% in British Columbia. Requirements for response time varies widely between provinces, ranging from fast response speed in Ontario to no specification in other provinces.

A summary of voltage and reactive power requirements with reported minimums may be found in Table 2 and Table 3 below.

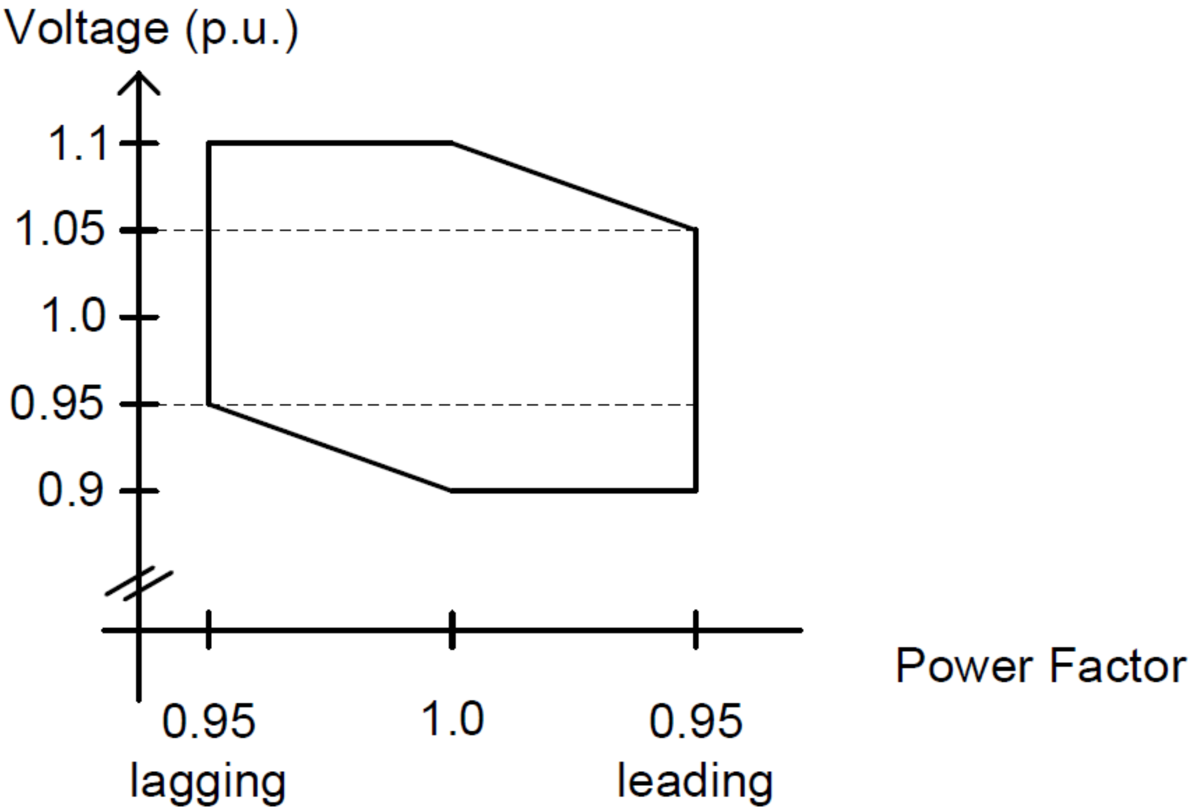


Figure 4: HQ Voltage-dependent Reactive Capability

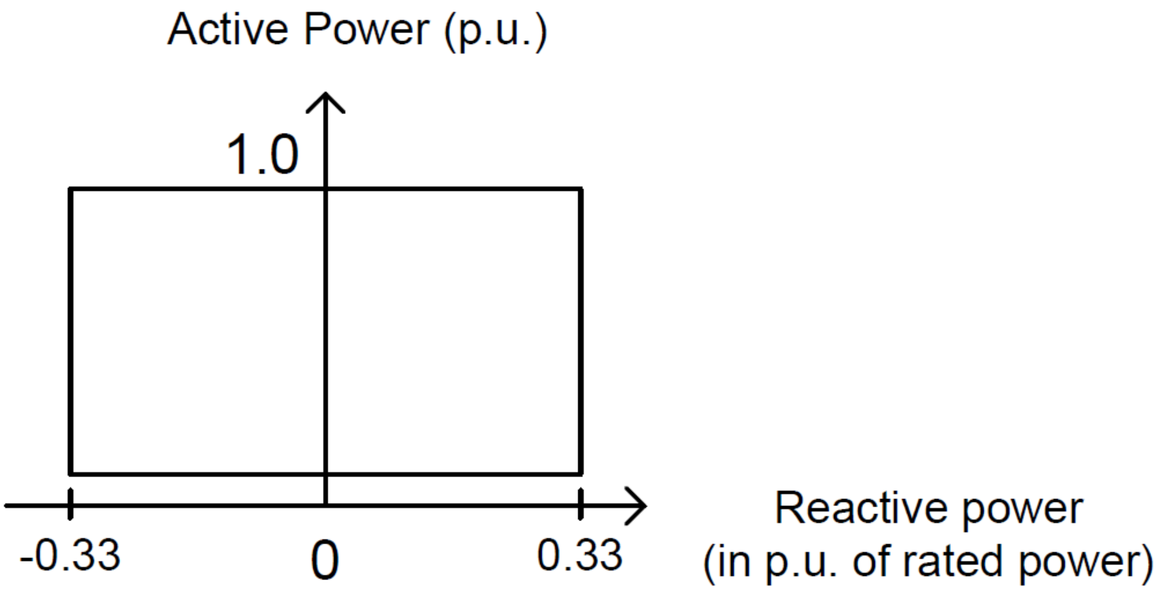


Figure 5: HQ Reactive Capability Curve

Table 2: Canadian provincial requirements for voltage regulation

Grid Code Requirement	Attribute	Minimum Requirement	Summary
Voltage Regulation	Range	±5% Vrated	±5% Vrated: AB, ON, MB ±10% Vrated: QC, SK,NF, LB +10%--20% Vrated: BC Continuous Vreg: NS, NB, PE
	Droop	Adjustable	Adjustable: ON Adjustable 0-10%: AB, QC, SK Adjustable up to 60%: NS
	Resolution	±0.5%	±0.5%: AB, ON, NS ±0.1%: BC
	Response Time	Depends on SIA	<= 1sec: AB, SK Equivalent to Synch Machine: ON, NS Depends on SIA (SIS), >100ms: MB
Point of Regulation		Based on Contract	High Voltage: AB, QC, SK, ON (w/ droop) Medium Voltage: NS (HV allowed) Contractual: MB, NB, PE, BC

Table 3: Canadian provincial requirements for reactive power capability

Grid Code Requirement	Attribute	Minimum Requirement	Summary
Reactive Power Capability	PF/VAR Range	±0.95	+0.90 to -0.95: AB, MB, NF, LB, NS, NB, BC +0.85 to -0.95: NS (>75MW) +/-0.95 pf: QC, ON, SK (wind), BC & NS (wind/solar), PE Must be dispatchable: NS A portion of reactive power must be dynamic everywhere.
	Active Power Range	Continuous, Studies Determine	P ≥ Pmin: AB, ON, QC Continuous Rated, Studies determine: MB Rated Q over entire P range: NS 'P>0.1*Pmax: SK
	Zero Active Power	Allowed	Allowed: ON, SK

3.2 Balancing & Regulation

AGC is generally required on dispatchable plants, but specific requirements in each province are widely variable. Maximum ramp rate control varies widely but is generally required to be adjustable within a range. Forecasting is required in Manitoba and Saskatchewan. Forecasting and metrological data is required to be provided for variable energy plants everywhere except Newfoundland and Labrador.

A summary of balancing and regulation requirements may be found in Table 4.

Table 4: Canadian provincial requirements for balancing, regulation and forecasting

Grid Code Requirement	Attribute	Minimum Requirement	Summary
Balancing including ancillary services such as AGC (automatic generation control)	AGC	AGC Capable	AGC Capable: AB, MB, NS, NB, BC Provide upon request: SK
Maximum ramp rate control		2-60 Min adjustable	1MW resolution, 5-20%: AB, SK 2MW/sec: MB 2-60 Min adjustable: NF, LB 10% of Prated or 80MW/Min: BC
Generation forecast requirements		Required	Required in MB, SK NF
Measured meteorological data reporting	Forecasting & Meteorological Data	Required	Required except in: NF, LB Forecasting data not required in NS

3.3 Power Quality

Power quality requirements across Canada are grouped into three main attributes, flicker, harmonic distortion and unbalance. IEEE standard 519 is the most commonly referenced power quality standard across Canada for Flicker and harmonic distortion. More specific flicker requirements are listed in Alberta's and Manitoba's grid codes. IEEE 1453 specifies flicker withstand in Newfoundland and Labrador. Nova Scotia calls upon various IEEE standards for distortion. Imbalance is specified in Newfoundland, Labrador, Saskatchewan and British Columbia, with a range of 2-5%.

A summary of power quality requirements may be found in Table 5.

BC Hydro's voltage flicker withstand curve is found in Figure 6.

Table 5: Canadian provincial requirements for power quality

Grid Code Requirement	Attribute	Minimum Requirement	Summary
Power Quality	Flicker	IEEE 519	IEEE 519: SK, NB, BC IEEE 1453: NF, LB IEC61400-21: MB, NS IEC61000-3-7: NS Pst = 0.8, Plt = 0.6: AB, MB (based on CAN/CSA-C61000-3-7)
	Harmonics	IEEE 519	IEEE 519: AB, SK, NF, LB, NB, BC IEEE 142, 519, 1100, 1159: NS ANSI C84.1 & IEC61000-3-6: NS
	Imbalance	<2%	<2%: NF, LB <3%: SK <1%Voltage, <5% Current: BC

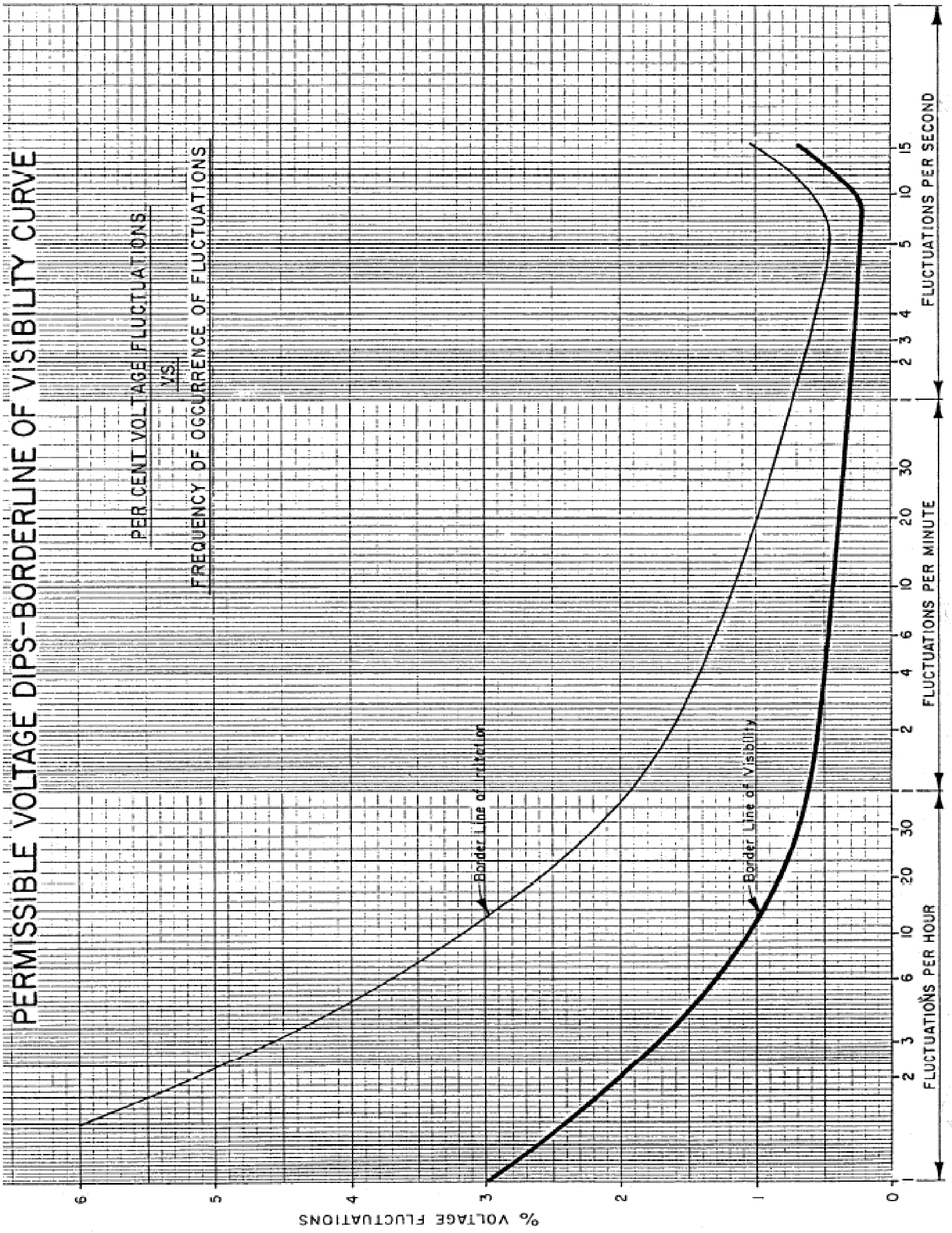


Figure 6: BC Hydro Flicker Curve

3.4 Protection

Protection requirements vary widely throughout Canada and are generally specified in every province. Protection is generally required to be reliable, selective and secure, tripping appropriately for disturbances and avoiding false trips for all disturbance types. Black start and system restoration is also generally specified in all provinces but is not specified for inverter-based resources. In addition to local requirements, NERC standards EOP-005 and EOP-006 also specify black start and system restoration provisions and establishment of cranking paths.

A summary of protection requirements across Canada may be found in Table 6.

Table 6: Canadian provincial requirements for protection

Grid Code Requirement	Minimum Requirement	Summary
System Restoration & Black Start	If Requested	Generally specified in all provinces. Not specified for IBRs.
Protective relaying	Must cover all fault types	Generally specified, widely varies by province.

3.5 Frequency Stability & Recovery

Requirements for Frequency control are evolving as system needs and generation mix evolves. The requirements across Canada for frequency regulation vary widely and include attributes such as droop characteristics, dead band, control resolution, response time and inertial (or Fast Frequency) response. Frequency droop is specified in every province, but the range widely varies. Most provinces require an adjustable frequency droop setting. Frequency dead band varies from ±36 mHz in Alberta, Ontario, Saskatchewan, Manitoba and British Columbia to a maximum of ±500 mHz adjustable in Quebec. Control resolution is specified in Alberta, Saskatchewan and Ontario. Response time is specified in Ontario. Inertial response (or Fast Frequency Response) is specified in Ontario, Quebec, Saskatchewan, Newfoundland, Labrador and Nova Scotia with widely varying performance requirements.

A summary of frequency response requirements may be found in Table 7.

Figure 7 shows recommended frequency control performance guidelines specified in Saskatchewan.

Table 7: Canadian provincial requirements for frequency stability & recovery

Grid Code Requirement	Attribute	Minimum Requirement	Summary
Frequency Response	PFR Droop range	Adjustable	Widely varies by Province Up regulation required only asych gen curtailed: NS
	PFR Dead band	Widest DB setting: ±500mHz	Max ±36 mHz: AB, ON, SK, MB, BC Max ±500 mHz: QC Synch Speed Gov ±0.06Hz & Asych. ±0.2Hz: NS Range to 0Hz adjustable: NF
	PFR Resolution	±0.06%	±0.004 Hz: AB, SK ±0.06%: ON IEEE 125/122: MB Immediate and sustained response: BC
	PFR Response Time	≥0.1xPrat after 10 sec	≥0.1xPrat after 10 sec: ON
	Inertial Response	≥0.06xPrat for 9 sec	Required in: ON, QC, SK, NF, LB, NS Widely varies by Province

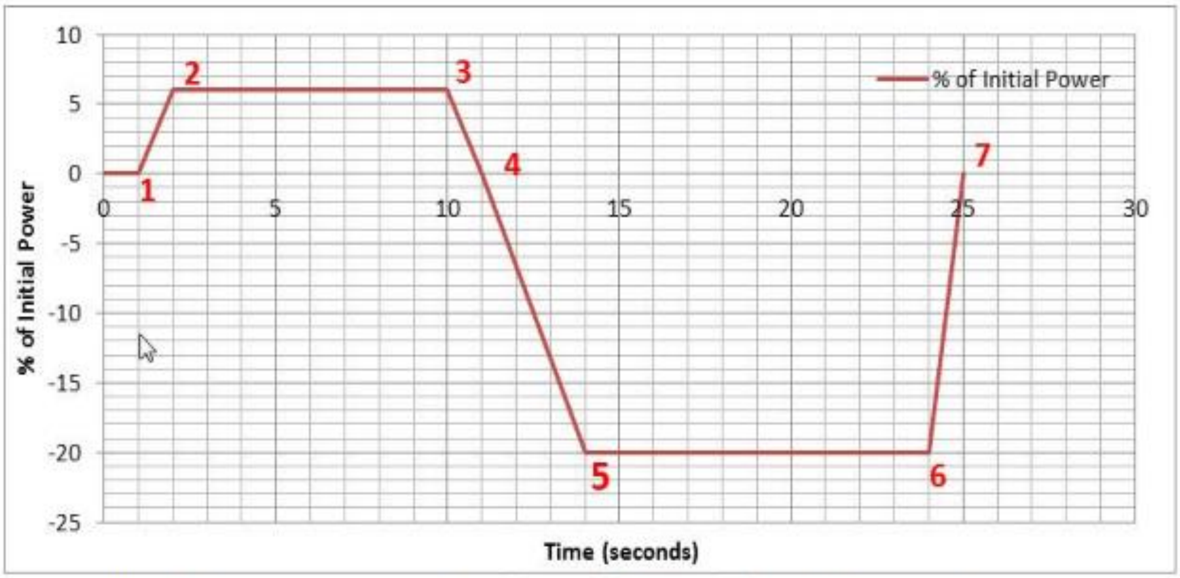


Figure 4: Recommended Performance Guidelines for Inertial Response[23]

Figure 7: Saskatchewan Inertial Response Capability: Wind and PV Solar

3.6 Large Signal Stability & Performance During and After Faults

There are extensive and well-defined requirements in all Canadian grid codes for large signal stability and performance during and after disturbances. This includes voltage and frequency ride-through, management of active and reactive power and current injection during and after faults, momentary cessation and islanding.

Figure 8 and Figure 9 compare voltage ride through requirements across Canada and selected international requirements in Ireland (EIRGRID), U.K. (National Grid), Australia (AEMO), USA (NERC) as well as with the curves specified in IEEE-1547-2018. Generally, all provinces have a continuous voltage withstand requirement at ±10% at the point of connection and zero voltage ride-through for 150-160ms. HVRT requirements vary widely from 120% to unbounded instantaneous (< 33ms) V_{POI} withstand.

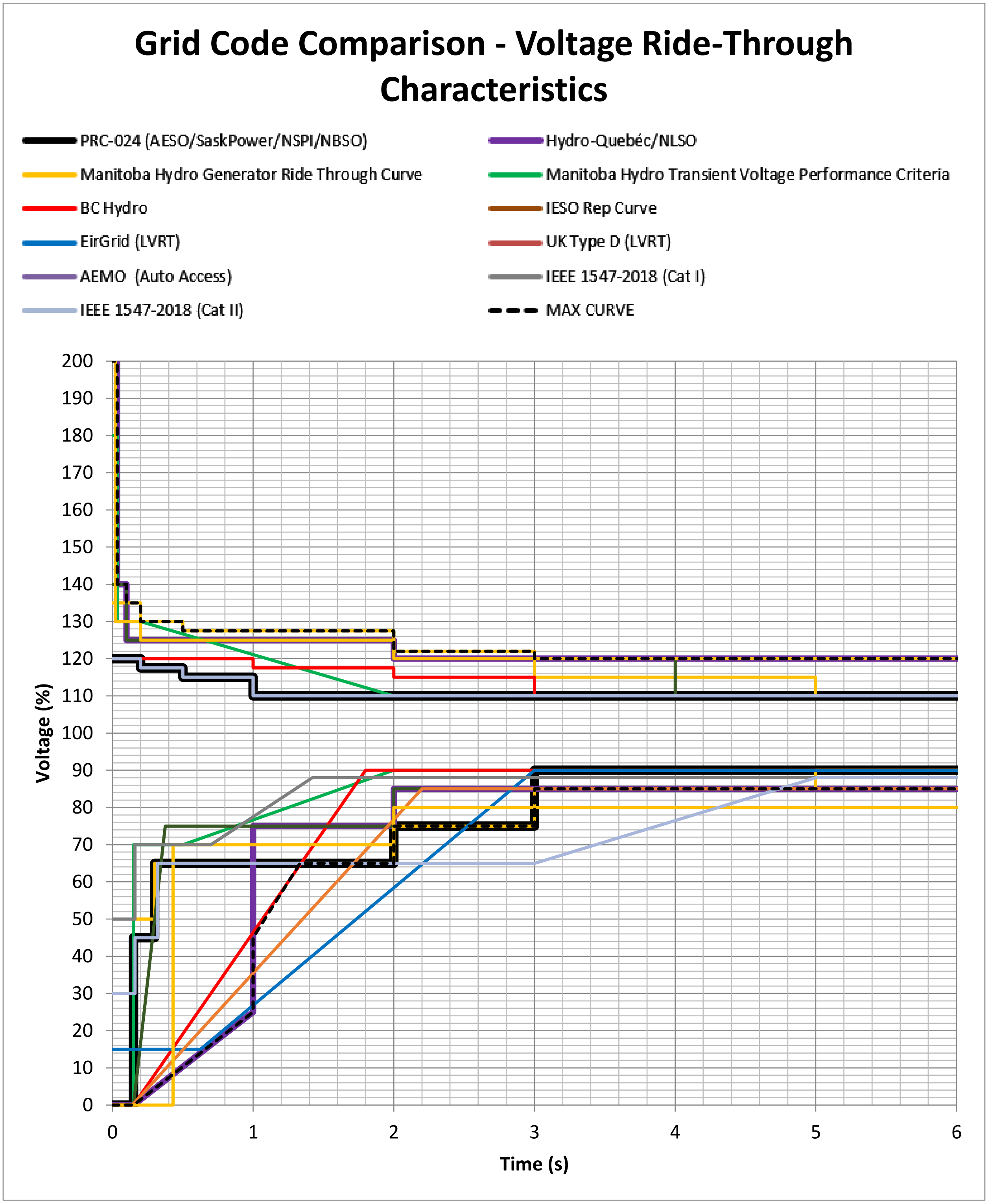


Figure 8: Canadian and international voltage ride-through requirements

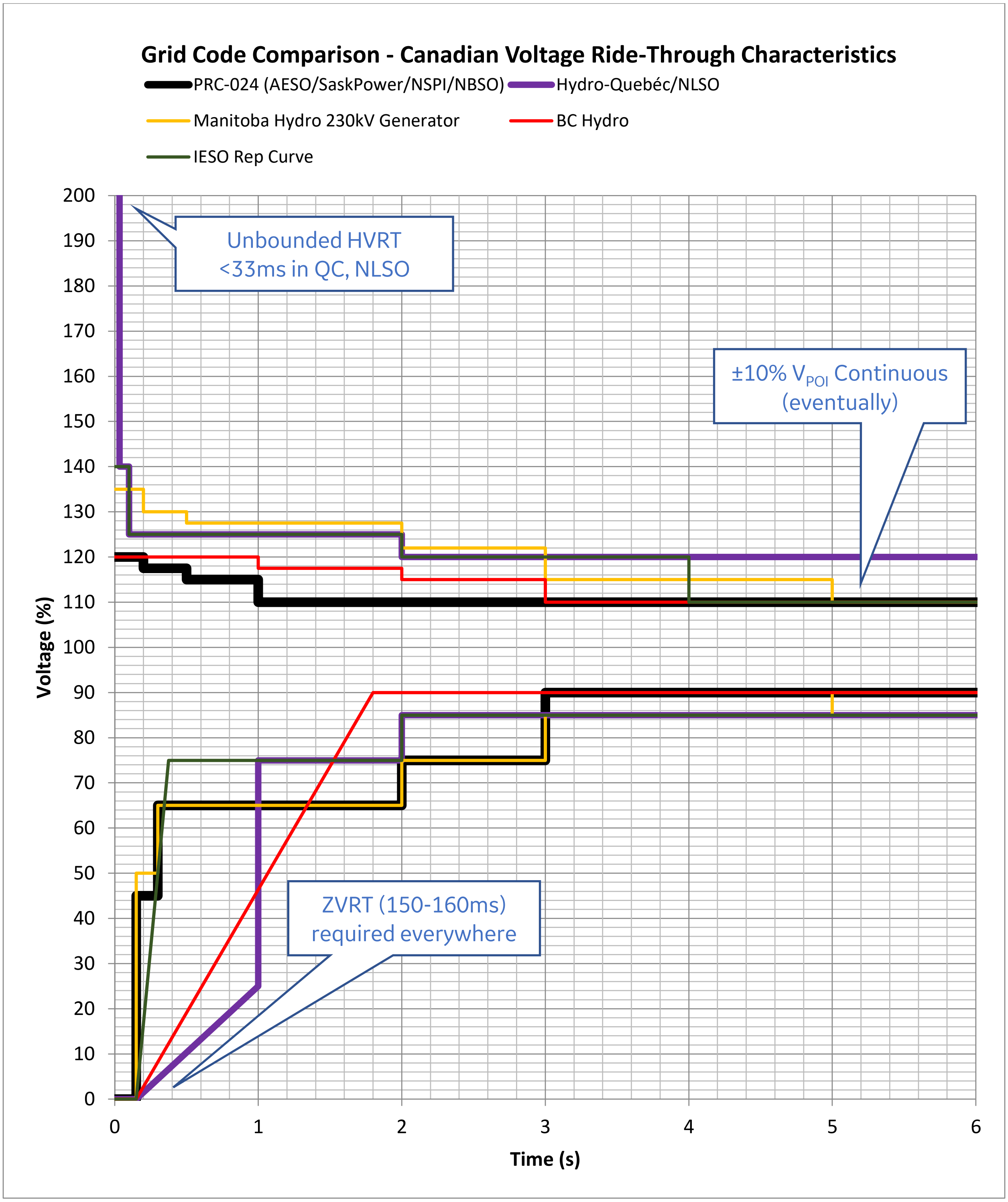


Figure 9: Canadian voltage ride through requirements

Figure 10 and Figure 11 compare frequency ride through requirements across Canada and selected international requirements. Most provinces have a continuous frequency withstand capability of ±0.5Hz and Manitoba has ±1Hz. Instantaneous withstand range varies, at minimum, between 58.7Hz – 60.5Hz (HFRT in Ontario and LFRT in Saskatchewan), and at maximum, 55.5Hz – 66Hz in Quebec.

The minimum voltage ride through and interconnection frequency ride-through requirements specified in NERC PRC-024 are well captured and coordinated with the Canadian grid code requirements and may be considered a good base requirement to harmonize across the provinces. Wider voltage ride-through requirements in each of the provincial codes may augment the specific needs in each provincial grid. Conversely, the dotted black line labeled MAX CURVE in

Figure 8 represents the maximum composite voltage ride-through requirement across Canada. There are specific requirements in some provinces, such as Nova Scotia where wind energy is required to provide reactive power during a grid fault "to the greatest extent possible" and also to recover at a rate of 0.1 to 5.0 pu/second once the fault is cleared.

Table 8 summarizes various other requirements related to large signal stability and performance during disturbances from the list proposed earlier in this report. Momentary cessation, a performance characteristic when IBRs block current output due to voltage or frequency transients caused by grid faults, is called out in Saskatchewan, Quebec and Labrador codes. It is prohibited for voltage and frequency perturbations that fall inside the NERC PRC-024 ride-through curves in Saskatchewan, and only allowed as a means to avoid equipment damage if voltages exceed 125% in Quebec and Labrador. Phase jump immunity and phase-locked-loop ride-through are not specifically called out in any Canadian codes. Requirements specifying return-to-service following a plant or unit tripping event is specified in Ontario, Alberta and British Columbia, where, at minimum, the plant or generation units must reconnect after fault clearing. Operating in an electrical island mode (separated from the bulk electrical grid) is not allowed in New Brunswick, Nova Scotia or Newfoundland. Islanding is allowed with prior coordination with the grid operator in Saskatchewan, Alberta, Ontario and Quebec. In cases where studies indicate the reliability of the electric grid may be jeopardized, Manitoba may require the generator to install anti-islanding protection. Finally, inverter current injection during faults is specified in Saskatchewan to have a reaction time after fault inception within 16ms and control action rise time of 100ms. In Manitoba, the reactive power output if the generator shall respond in a controlled fashion to help system voltage recovery following a disturbance.

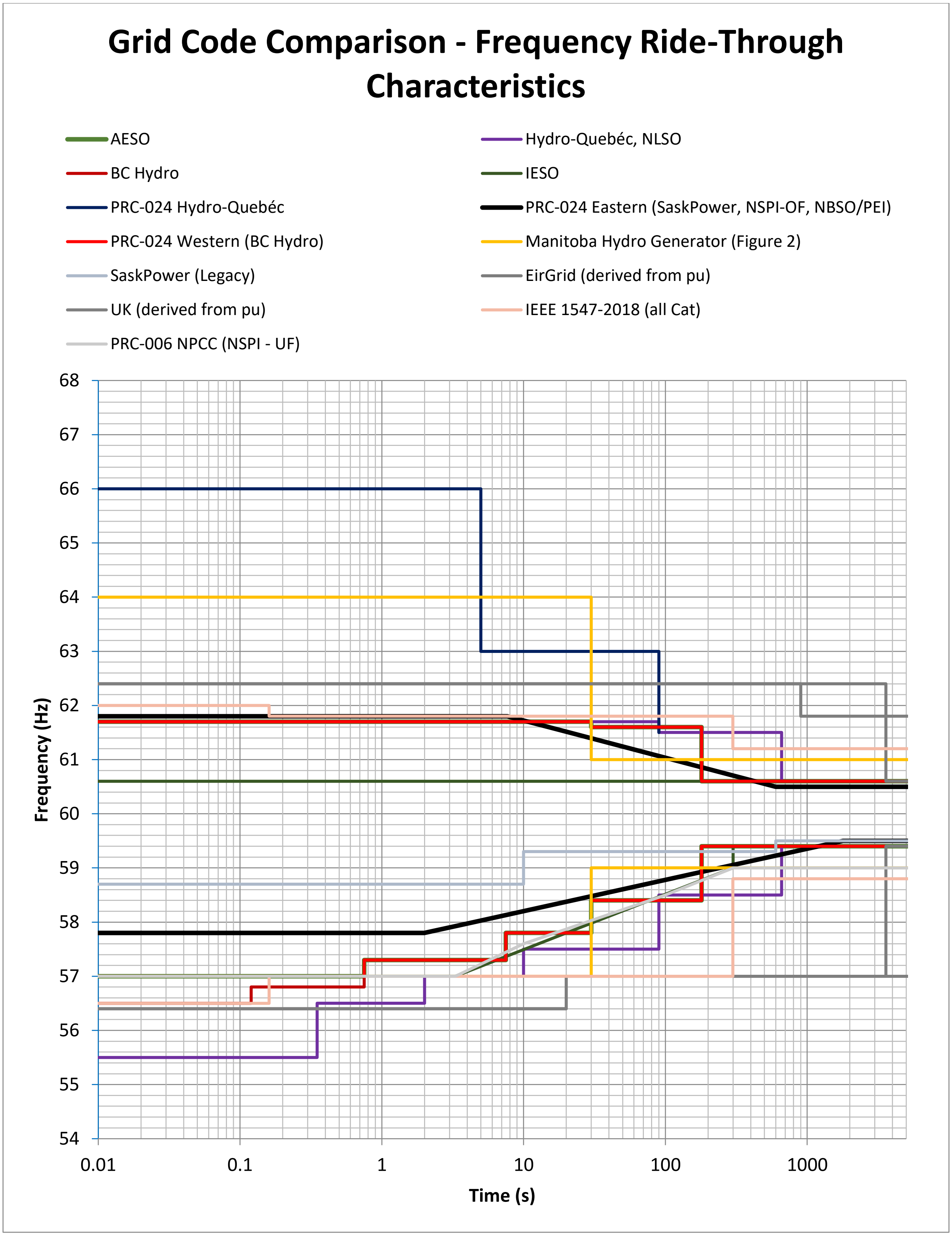


Figure 10: Canadian and international frequency ride-through requirements

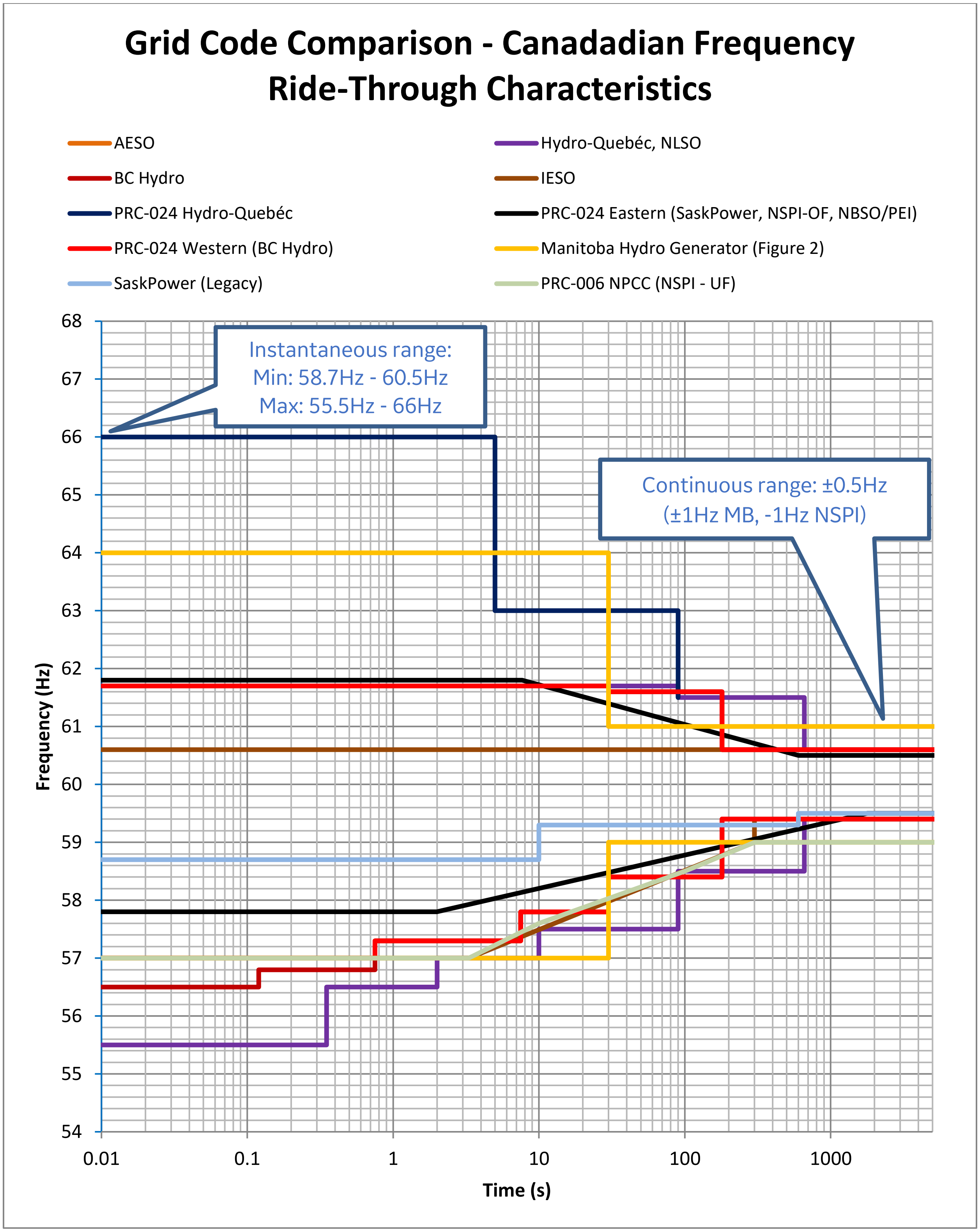


Figure 11: Canadian frequency ride-through requirements

Table 8: Canadian provincial requirements for large-signal stability and performance during disturbances

Grid Code Requirement	Minimum Requirement	Summary
Momentary Cessation	Prohibited inside PRC-024 curve	Permissive > 1.25puV: QC, LB Prohibited inside PRC-024 curves: SK
Phase jump immunity including phase-locked loop ride-through	Not specified	Not specified
Return to Service Following Tripping	May reconnect upon satisfaction of grid operator and provide proof that reason for disconnection no longer exists	Mostly unspecified except in ON and AB
Anti-Islanding protection and island mode operation	Additional protection required	Not allowed in NB, NS, NF In coordination with system operator: SK, AB, ON, QC Additional studies required and protection may be required: MB
Inverter current injection during faults	Respond in a controlled fashion	reaction time <16ms rise time <100ms: SK respond in a controlled fashion : MB

3.7 Small Signal Stability & Damping

A summary of small signal stability and damping requirements may be found in Table 9. Power system stabilizers required in all provinces except PE and NB for Synchronous Machines. Power oscillation damping (POD) capability is required for wind plants in Newfoundland and Labrador and may be required in Alberta if WECC requires it. Additionally, Alberta, Ontario, Quebec, Saskatchewan, Nova Scotia and Manitoba grid codes require that generation or grid controls must not cause instability under defined grid operating conditions. Screening is required via system study to determine the risk of sub-synchronous resonance or sub-synchronous control interaction in Alberta, Quebec, Saskatchewan and Manitoba. Additional requirements to avoid instabilities due to low frequency resonance and application of additional plant protection are called for in these provinces.

Table 9: Canadian provincial requirements for small signal stability & damping

Grid Code Requirement	Minimum Requirement	Summary
Power System Stabilizer	Synchronous Generation Only	Synch Gen only: SK, MB, NS, BC Asynch required if WECC does: AB Designed to be equipped with PSS: NF, LB
Power System Damping and small signal stability	Must not cause instability	Must not cause instability: AB, ON, QC, SK, MB, NS Min damping ratio of 0.04, requires mitigation <0.04: MB 30% max overshoot, max 2 swings and settle within 2 sec: SK
Sub-synchronous resonance (SSR) and Sub-synchronous control interaction (SSCI)	Screening Required	Specific requirements in AB, QC, SK, MB

3.8 Modeling & Data

A summary of modeling and data requirements may be found in Table 10. Generally, validated Positive Sequence Fundamental Frequency models required in PSS/e in all provinces. EMT models required in Quebec (EMTP-RV), Saskatchewan and British Columbia (PSCAD). Manitoba and Nova Scotia generally call for transient models if required by the grid operator. WECC Generic GENII models preferred in Ontario and Nova Scotia. All provinces require validated positive sequence models per NERC MOD-025 (MW, MVAr), -026 (excitation and plant volt/var control dynamic models) and -027 (governor and frequency control dynamic models). Each province has specific monitoring and data reporting requirements, but at a minimum, real power (MW), reactive power (MVAr), phase voltage quantities are required across Canada and 10-min data for weather quantities are specified everywhere except Newfoundland, Labrador and Prince Edward Island.

Table 10: Canadian provincial requirements for modeling & data

Grid Code Requirement	**Minimum Requirement**	**Summary**
Data Reporting and Monitoring	MW, MVAr, phase voltage quantities	Each province has specific data reporting requirements.
Modeling	Validated PSS/e models per NERC MOD	PSS/e: NF, LB PSS/e + PSCAD, EMTP-RV or other: QC, SK, MB, NS, BC Generic WECC Models: ON, NS
Generation forecast requirements	Required	Required in MB, SK NF
Measured meteorological data reporting	Required	Required except in: NF, LB Forecasting data not required in NS

3.9 High IBR Penetration

A summary of requirements related to high IBR penetration may be found in Table 11. These requirements address control stability due to high-impedance or low short circuit ratio networks and newer technologies to mitigate effects of high penetration, such as grid forming controls and battery energy storage. Presently, there are no specific requirements for grid forming capabilities or battery energy storage called out in Canadian codes, absent a reference in Alberta that battery energy storage must adhere to the same requirements as other inverter-based resources.

Table 11: Canadian provincial requirements for system needs related to high IBR penetration

Grid Code Requirement	Minimum Requirement	Summary
Control stability, control interactions & weak grid connection	SCR Screening	Weak System Analysis or performance requirements specified in: AB, QC, MB, NS Provide Minimum SCR: SK, NS
Grid Forming Controls	No specific Requirements	No Specific Requirements
Battery Energy Storage Requirements	Same as renewable Generation	Not independently specified, except in AB – same as renewable generation.

4 REVIEW AND SUMMARY OF SELECTED INTERNATIONAL GRID CODES

Like in the previous section, an in-depth review has been conducted of selected global grid codes by GE Energy Consulting. This review focuses on transmission system and distribution-level considerations that could affect the bulk electrical system, such as fault ride-through. An examination of the existing interconnection requirements of energy storage technologies was included in this review. The technical aspects listed in the previous section were also compared for global codes and are summarized in this section.

The global codes, requirements, recommendations and practices reviewed for this report include[2]:

- **North American Electric Reliability Corporation (NERC) standards and reliability Guidelines**
- **Electric Reliability Council of Texas (ERCOT) Nodal Protocols and Operating Guide**
- **California Independent System Operator (CAISO) Open Access Transmission Tariff**
- **Eirgrid grid code for Ireland**
- **National Grid Electric System Operator (NGESO)[3] grid code for Great Britain**
- **Australian Electricity Market Operator (AEMO) grid code for Australia**

Table 12 shows a summary and comparison of grid code requirements across for selected countries and areas around the world. It weighs the relative complexity and specificity of requirements across all grid codes, with darker green indicating more detailed or prescribed performance and lighter green indicating simpler or generalized requirements.

A general trend is that grid codes from AEMO, Eirgrid and NG ESO tend to be more detailed, complex and prescriptive relative to North American codes. Requirements are written there to specify a very specific response to mitigate specific issues they may be facing. This is largely due to the fact that Australia, Ireland and Great Britain are smaller systems with limited to no interconnection with neighbors. Islanded electrical systems tend to have more challenging conditions and needs. These systems are also experiencing higher penetration of IBR and have high decarbonization targets that will drive even higher IBR penetration in the future. Prescriptive codes may help achieve specific needs, but they may also limit the capabilities of new technologies and methods to resolve those needs. They also may limit penetration of a particular class of resources due to the cost of interconnecting and successfully deploying equipment in each project to meet the requirements.

As previously stated, North American requirements are less prescriptive. NERC sets overall reliability requirements as to what is required from each entity but does not specify details regarding how those requirements are met. Each region, ISO, RTO or utility decides if more detailed requirements are necessary and what those requirements are. Texas and California have different system needs due to different grid challenges and this is reflected in ERCOT's nodal protocols and operating guide and CAISO's Open Access Transmission Tariff (OATT).

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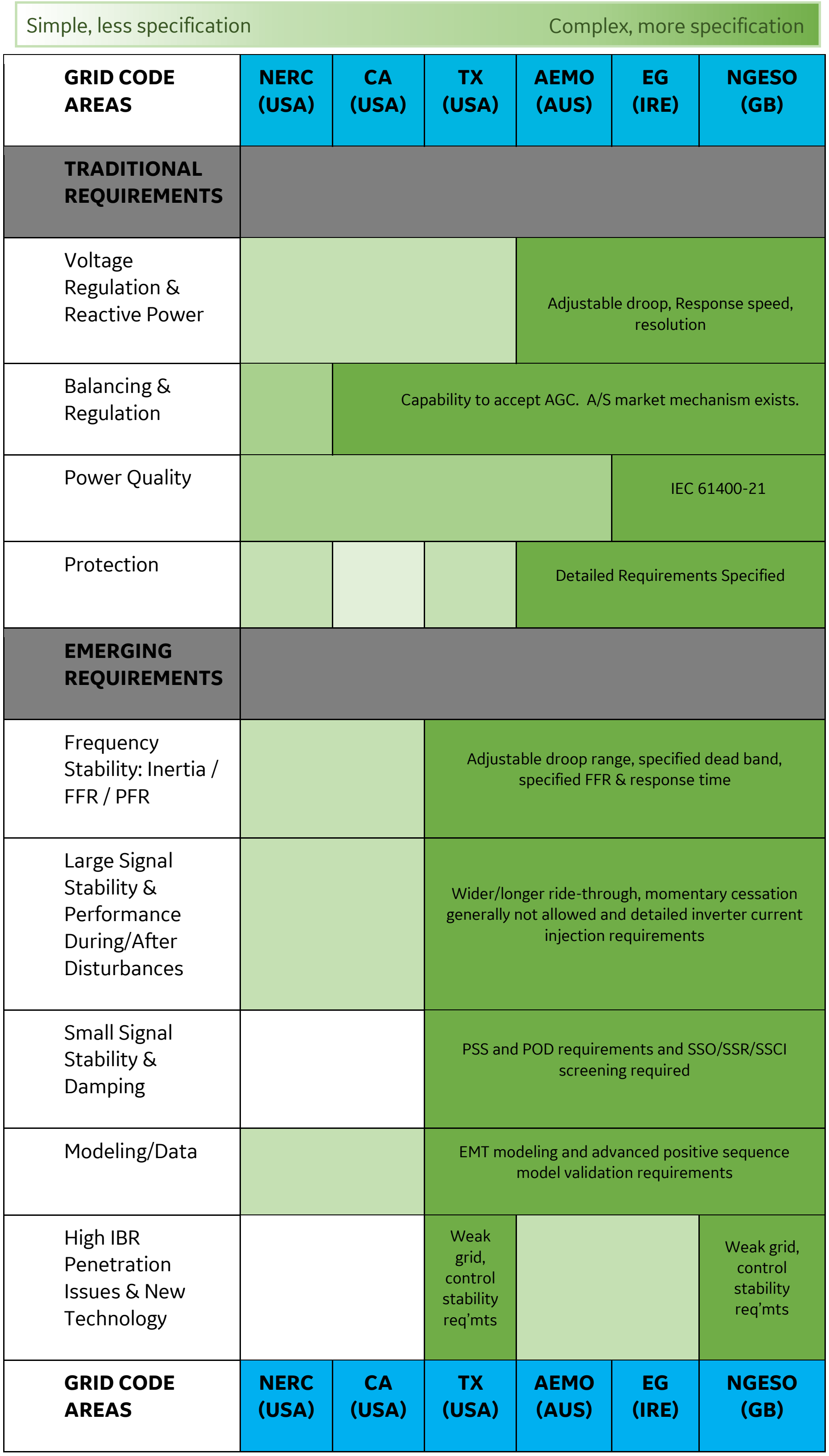
[2] Information in this section is accurate as of the publication date of this report.

[3] Does not apply to Northern Ireland.

Table 12: Comparison of requirements outside of Canada



Simple, less specification — Complex, more specification

<table>
<tr><th>GRID CODE AREAS</th><th>NERC (USA)</th><th>CA (USA)</th><th>TX (USA)</th><th>AEMO (AUS)</th><th>EG (IRE)</th><th>NGESO (GB)</th></tr>
<tr><td>TRADITIONAL REQUIREMENTS</td><td colspan="6"></td></tr>
<tr><td>Voltage Regulation & Reactive Power</td><td colspan="3"></td><td colspan="3">Adjustable droop, Response speed, resolution</td></tr>
<tr><td>Balancing & Regulation</td><td></td><td colspan="5">Capability to accept AGC. A/S market mechanism exists.</td></tr>
<tr><td>Power Quality</td><td colspan="4"></td><td colspan="2">IEC 61400-21</td></tr>
<tr><td>Protection</td><td></td><td></td><td></td><td colspan="3">Detailed Requirements Specified</td></tr>
<tr><td>EMERGING REQUIREMENTS</td><td colspan="6"></td></tr>
<tr><td>Frequency Stability: Inertia / FFR / PFR</td><td colspan="2"></td><td colspan="4">Adjustable droop range, specified dead band, specified FFR & response time</td></tr>
<tr><td>Large Signal Stability & Performance During/After Disturbances</td><td colspan="2"></td><td colspan="4">Wider/longer ride-through, momentary cessation generally not allowed and detailed inverter current injection requirements</td></tr>
<tr><td>Small Signal Stability & Damping</td><td colspan="2"></td><td colspan="4">PSS and POD requirements and SSO/SSR/SSCI screening required</td></tr>
<tr><td>Modeling/Data</td><td colspan="2"></td><td colspan="4">EMT modeling and advanced positive sequence model validation requirements</td></tr>
<tr><td>High IBR Penetration Issues & New Technology</td><td colspan="2"></td><td>Weak grid, control stability req'mts</td><td colspan="2"></td><td>Weak grid, control stability req'mts</td></tr>
<tr><td>GRID CODE AREAS</td><td>NERC (USA)</td><td>CA (USA)</td><td>TX (USA)</td><td>AEMO (AUS)</td><td>EG (IRE)</td><td>NGESO (GB)</td></tr>
</table>

4.1 Voltage Regulation & Reactive Power

Voltage regulation and reactive power requirements are somewhat consistent across the global standards reviewed in this report. A power factor requirement of ±0.95pf is common across Republic of Ireland, Great Britain, Texas and California. In Australia, a ±0.93pf is required with 50% of that reactive capability being dynamic. Active power range for reactive capability is specified for all power levels in Ireland, Australia and California, above 20% Pgen in Great Britain and in a range of 10%-100% for Texas. Voltage must be regulated in a range of ±5% except for Texas, which specifies ±4%. Voltage droop is required in Ireland and Great Britain within a range of 2-7% and in Texas where the droop and voltage offset is less than 2%. Accuracy resolution is required to be within 0.5% in Australia and Great Britain and within 1% in Ireland. There are specific and extensive response time requirements in Ireland, Australia and Great Britain. All codes generally specify the point of connection as the high voltage terminals of the power plant substation or generator step-up transformer. In California, this is specified at the time of plant interconnection registration.

Table 13 summarizes global requirements for voltage regulation and Table 14 summarizes global requirements for reactive power capability. Figure 12 - Figure 16 show the minimum and voltage-constrained reactive capability requirements at various voltage levels in Eirgrid and Great Britain.

Table 13: Global requirements for voltage regulation

Grid Code Requirement	**Attribute**	**Summary**
Voltage Regulation	Range	±5% Vrated: IE, AU, GB, CA ±4%: TX
	Droop	Adjustable 2-7%: IE, GB Vdroop + V <2%: TX
	Resolution	0.5%: AU, GB 1%: IE
	Response Time	specific requirements in IE, AU, GB
Point of Interconnection		Generally at HV side of GSU or Plant Transformer. Specified at registration for CA.

Table 14: Global requirements for reactive power capability

Grid Code Requirement	Attribute	Summary
Reactive Power Capability	PF/VAR Range	±0.95: IE, GB, TX, CA ±0.93: AU, 50% dynamic
	Active Power Range	All power levels: IE, AU, CA >20% Pgen: GB 10%-100% Pgen: TX
	Zero Active Power	Capability required in: IE, TX, GB

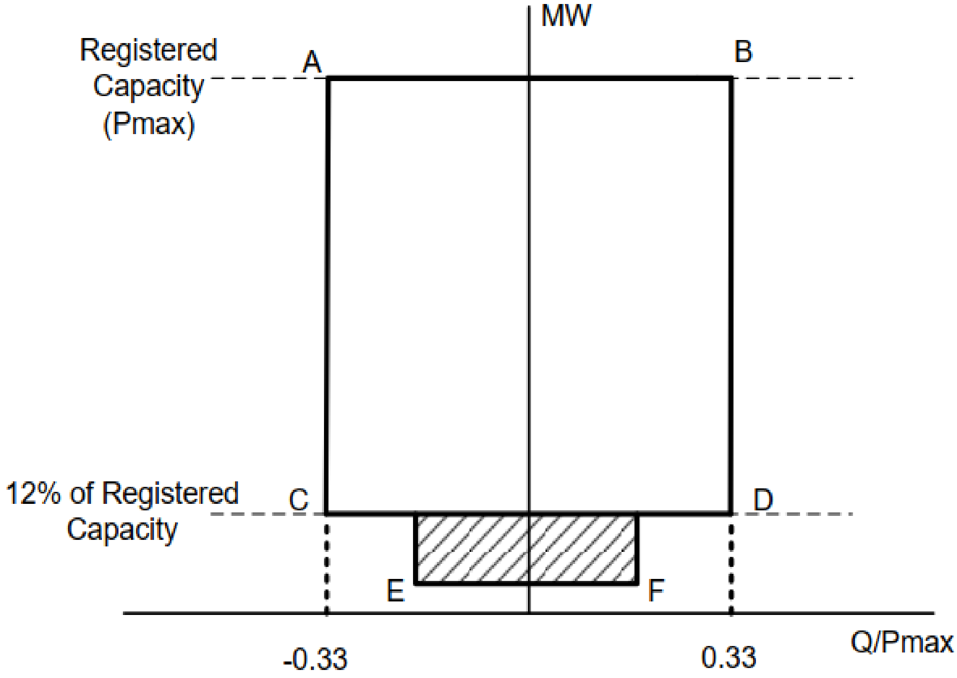


Figure PPM1.4– Minimum **Reactive Power** Capability of **Controllable PPM**

Figure 12: EIRGRID Reactive Capability

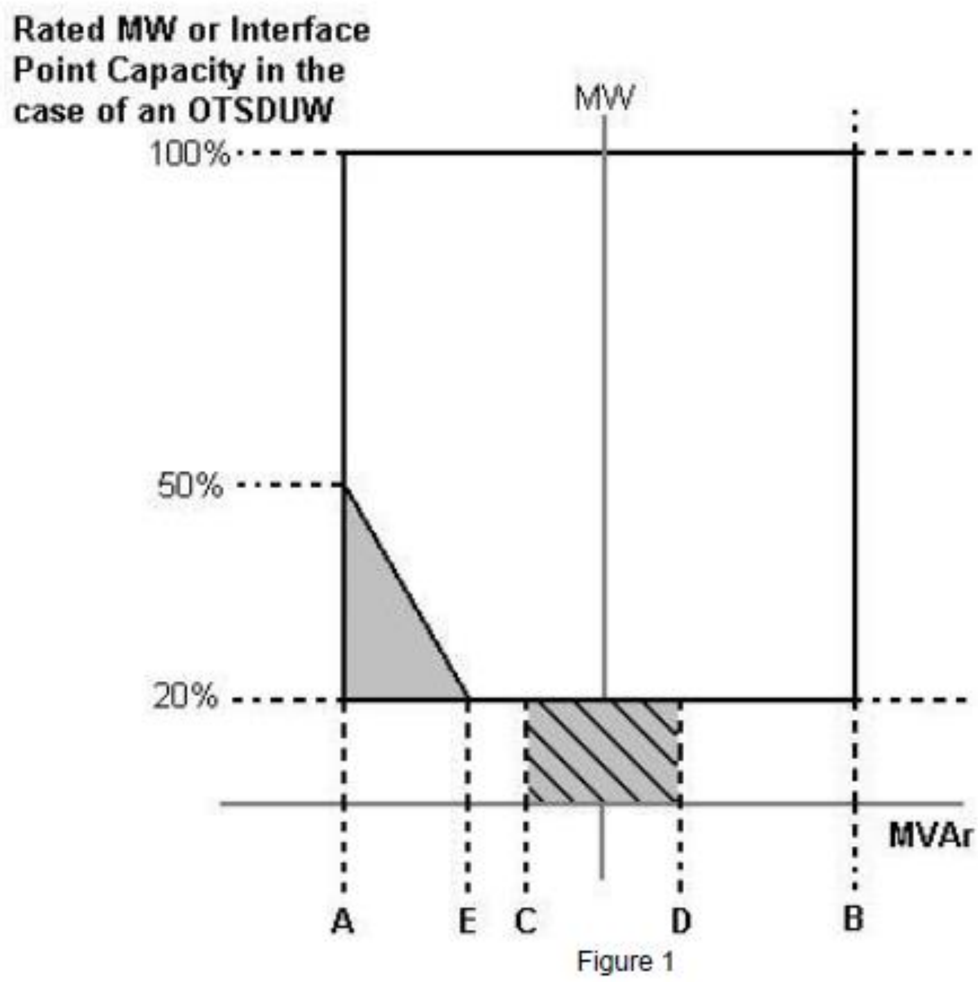


Figure 13: National Grid ESO reactive capability requirement

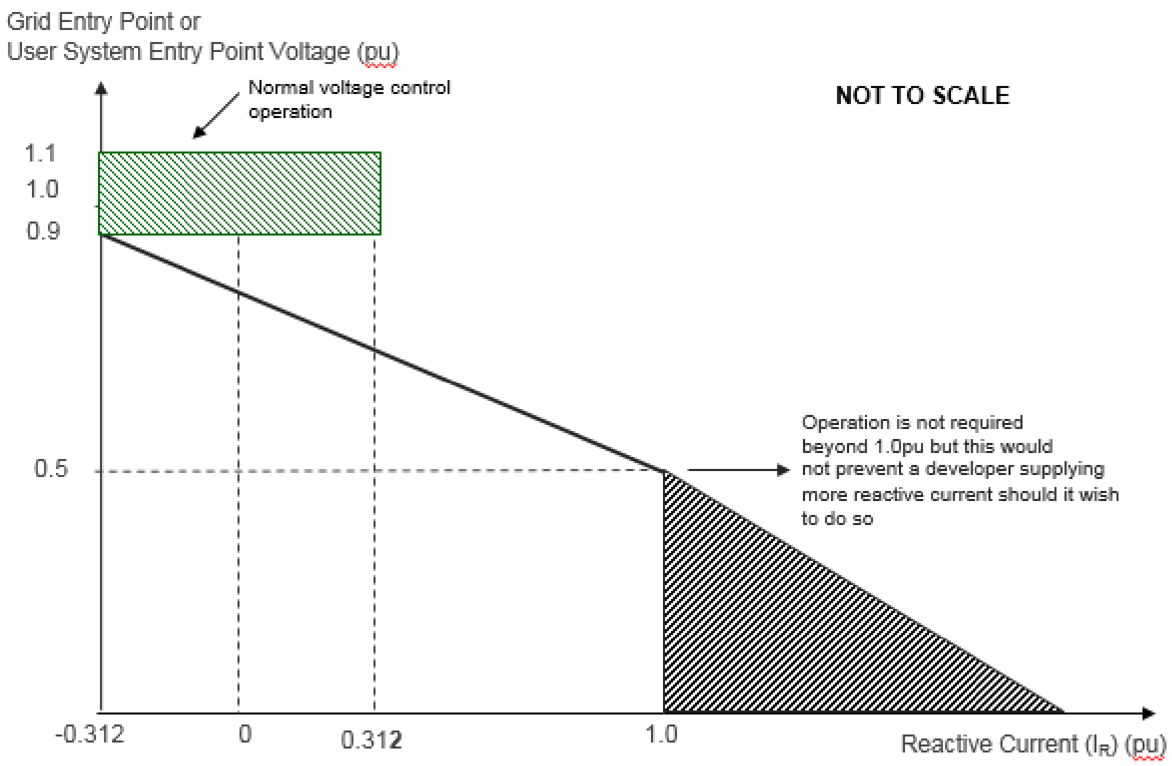


Figure 14: EIRGRID voltage-dependent reactive current capability

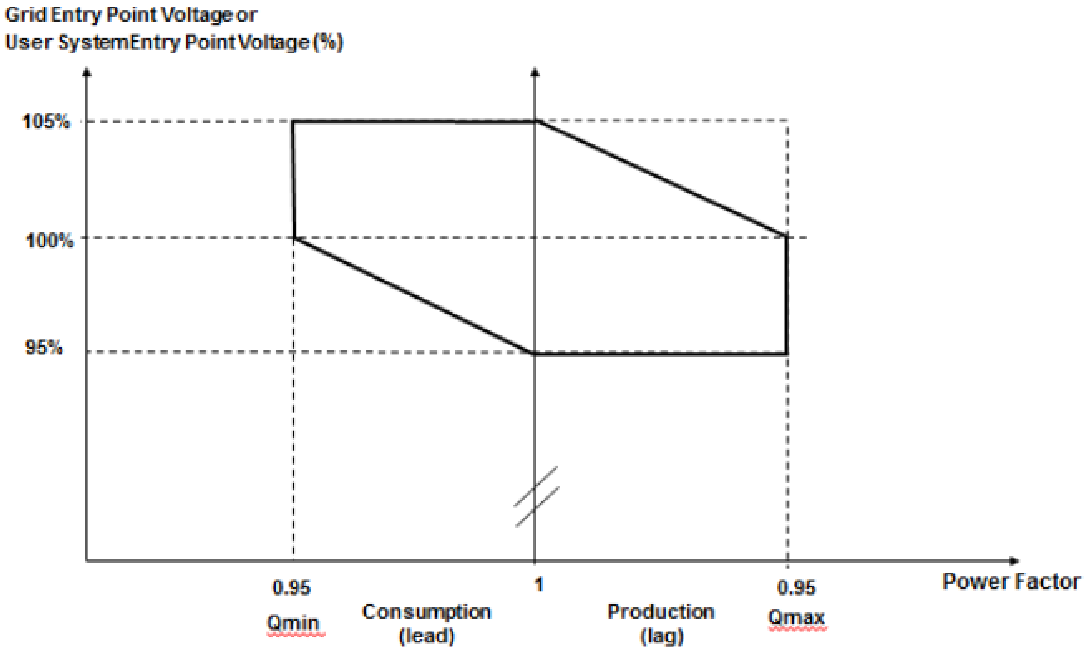


Figure ECC.6.3.2.4(a)

Figure 15: National Grid ESO voltage constrained reactive capability for IBR connected below 33kV

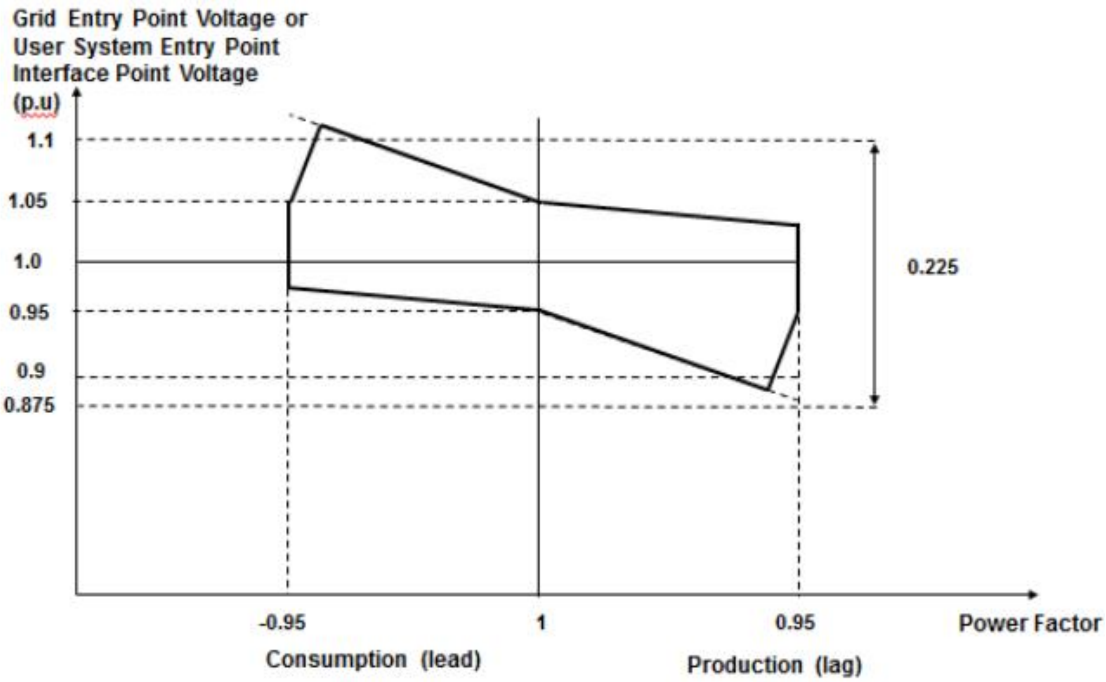


Figure ECC.6.3.2.4(a)

Figure 16: National Grid ESO voltage constrained reactive capability for IBR connected above 33kV

4.2 Balancing & Regulation

AGC capability is generally required on all plants in all regions, with a coupled ancillary services market mechanism to pay for frequency regulation in Ireland, Australia, Great Britain, Texas and California. Ramp rate control is specified in Ireland, Australia, Great Britain, Texas and California, with specific requirements in each region. Wind forecasting and meteorological data is required in Great Britain and Wind and Solar forecasting and data is required in Texas and California.

A summary of global balancing and regulation requirements may be found in Table 15.

Table 15: Global balancing and regulation requirements

Grid Code Requirement	Attribute	Summary
Balancing including ancillary services such as AGC (automatic generation control)	AGC	Capability to accept AGC required in all regions. A/S market mechanism for balancing in: IE, AU, GB, TX, CA
Maximum ramp rate control		Ramp rates required in EI, AU, GB, TX and CA. Widely varies per region.
Generation forecast requirements		Wind and solar forecasts required in TX and CA. Load forecasting required in EI, AU
Measured meteorological data reporting	Forecasting & Meteorological Data	Wind Forecast: GB Wind & Solar Forecasts: TX & CA

4.3 Power Quality

Three main aspects of global power quality requirements have been compared. These include voltage flicker, harmonics and unbalance. Generally, all power quality requirements are specific to each region, with heavy reference to IEC guidelines in Europe and Australia (such as IEC 61400-21) and IEEE guidelines in North America (such as IEEE 519). Maintaining <1% imbalance is specifically called out in Ireland's code.

A summary of global power quality requirements may be found in Table 16.

Table 16: Global power quality requirements

Grid Code Requirement	Attribute	Summary
Power Quality	Flicker	Specific to each region. Generally, IEC guidelines in EU and AU. IEEE standards in US.
	Harmonics	Specific to each region. Generally, IEC guidelines in EU and AU. IEEE standards in US
	Imbalance	Specific to each region. Generally, IEC guidelines in EU and AU. 1% unbalance in IE. IEEE standards in US.

4.4 Protection

Global protection requirements are very specific to each region or country. There are general trends throughout. The codes in Europe and Australia call out very specific protection requirements regarding coordination, selectivity and security to be sure proper protective action is taken to isolate a disturbance or abnormal operation but avoid mis-tripping. Black start and system restoration is also widely specified for each region and Australia and Great Britain have ancillary services markets to support black start capability. These requirements are set to establish minimum capabilities for black start resources, and in some areas (such as North America established by NERC CIP and EOP standards) requirements are set for evaluation and establishment of restoration cranking paths.

A summary of global protective relaying requirements may be found in Table 17.

Table 17: Global protective relaying requirements

Grid Code Requirement	**Summary**
System Restoration & Black Start	Black Start and restoration practices established for all regions. AU, GB have A/S markets for black start.
Protective relaying	Protection Requirements specific to each region/country. Generally requires selectivity & security.

4.5 Frequency Stability & Recovery

Frequency response requirements vary by global region. Several aspects of frequency response have been reviewed in global requirements, including frequency droop setting range, dead band setting range, control resolution, response time and inertial response provision and performance. Droop range is specified to be adjustable in all regions within ranges that span 0-4% in North America to 2-12% in Ireland. Dead band settings range generally from ±15mHz to ±36mHz in North America and Europe, and Australia requiring capability of an adjustable range within ±1Hz. Response time is specific to each region but is generally required in a range of 5-15 sec where specified. Inertial response (or fast frequency response for IBR) is required in Australia and Texas. Various levels of Frequency Sensitive Mode are required in Ireland and Great Britain.

A summary of global frequency response requirements may be found in Table 18.

An example of Eirgrid's power-frequency response requirements for resource following and frequency sensitive modes may be found in Figure 17 and Figure 18.

Table 18: Global frequency response requirements

Grid Code Requirement	Attribute	Summary
Frequency Response	Droop range	Adjustable in all regions. Min Range 0-4%: TX, CA. Max range 2-12%: IE
	Dead band	Adjustable to ±1Hz: AU Settings range from ±15 mHz to ±36 mHz: EI, NERC, TX, CA
	Resolution	Not Specified
	Response Time	Specific response requirements in EI, AU, GB, CA Where required, generally 5-15sec response time.
	Inertial Response	Specified everywhere except CA and NERC Reliability Standards. Paid A/S in AU. 15 cycle response and 15min deployment in TX as part of Responsive Reserve Requirement.

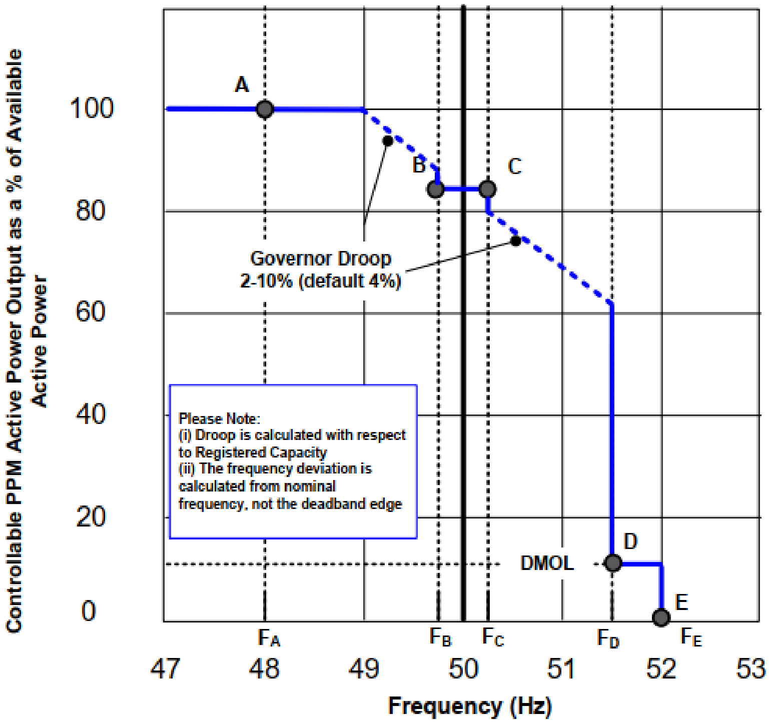


Figure 17: EIRGRID power-frequency response curve for Resource Following Mode

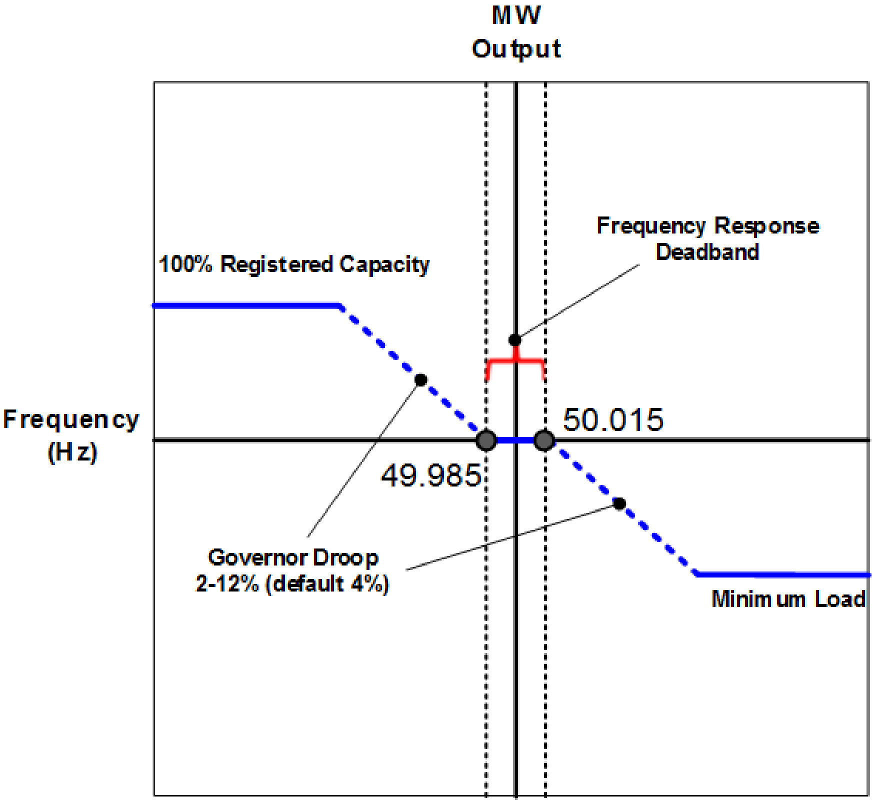


Figure 18: EIRGRID power-frequency response curve for Frequency Sensitive Mode

4.6 Large Signal Stability & Performance During and After Faults

There are extensive and well-defined requirements in all global grid codes investigated for large signal stability and performance during and after disturbances. This includes voltage and frequency ride-through, management of active and reactive power and current injection during and after faults, momentary cessation and islanding.

Figure 19 compares voltage ride through requirements across global requirements in Ireland (EIRGRID), U.K. (National Grid), Australia (AEMO), USA (NERC) as well as with the curves specified in IEEE-1547-2018. Generally, all areas have a continuous voltage withstand requirement at ±10% at the point of connection and zero voltage ride-through for 150-430ms. HVRT requirements vary widely from 120% to 200% instantaneous (< 20ms) V_{POI} withstand.

Figure 20 compares frequency ride through requirements across Canada and selected international requirements. Continuous frequency withstand capability ranges from ±0.5Hz to ±1Hz. Instantaneous withstand range varies and maximum range is -3.5Hz to +2Hz.

The span of Canadian ride through requirements is well aligned with the span of global requirements.

In addition to ride-through, Table 19 summarizes other aspects of large signal stability for global requirements. These aspects include momentary cessation, phase jump immunity, return to service following tripping, anti-islanding protection and inverter current injection during faults. Generally, momentary cessation is not allowed in North America per NERC guidelines. In Great Britain, it is allowed but must be modeled and evaluated during stability studies. Inverter tripping due to PLL instability or erroneous frequency measurement is addressed in North America through NERC guidelines and “should not be allowed”. Generally, return to service following a tripping event is specified in various ways in all locations except Australia. Islanding is not permitted Australia, Great Britain and US. There are specific requirements in each region for inverter current injection during grid faults. All regions are required to inject real and reactive current suitably to maintain grid stability.

Figure 21 shows an example reactive current injection capability requirement from Eirgrid.

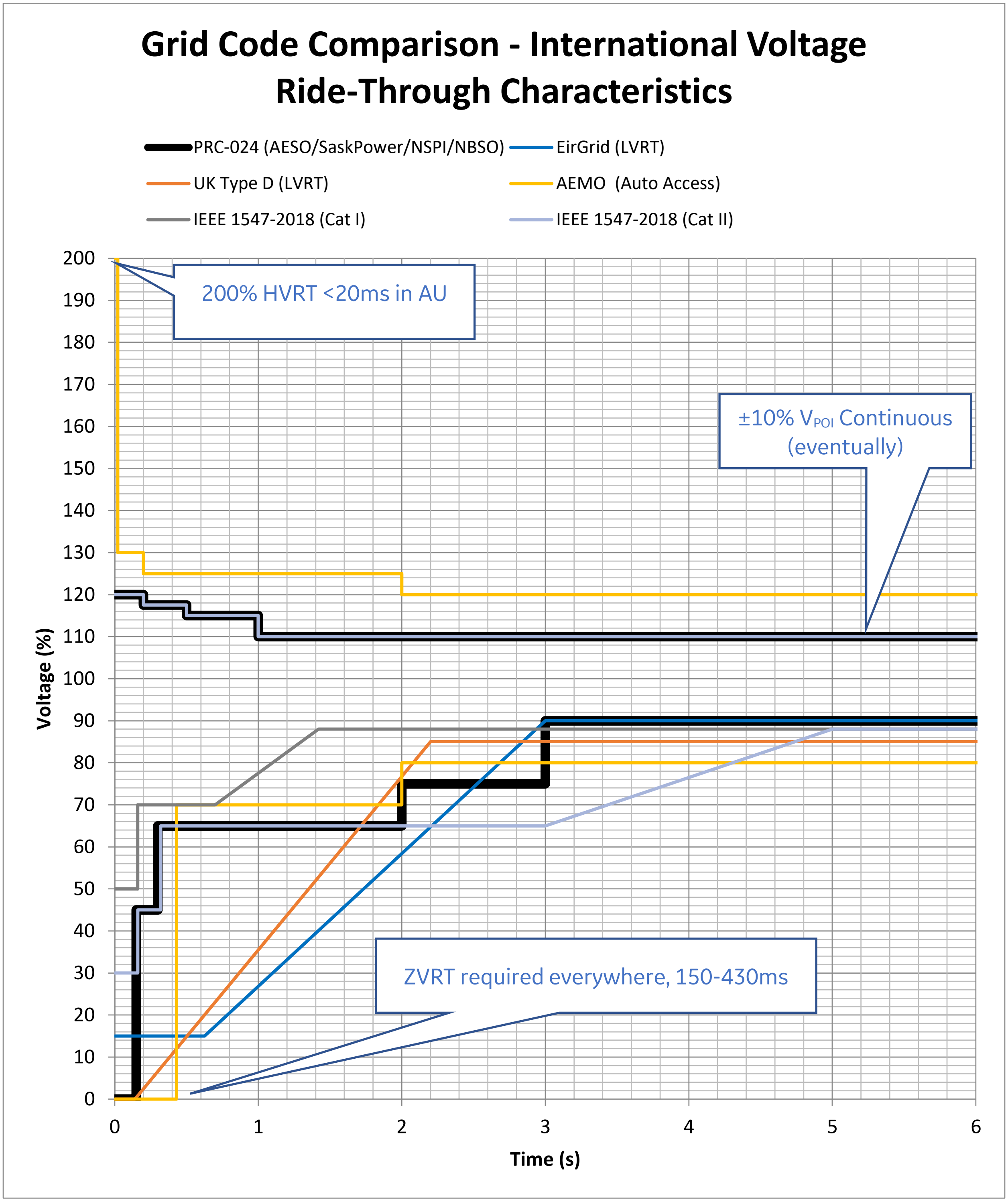


Figure 19: Comparison of voltage ride through requirements outside of Canada

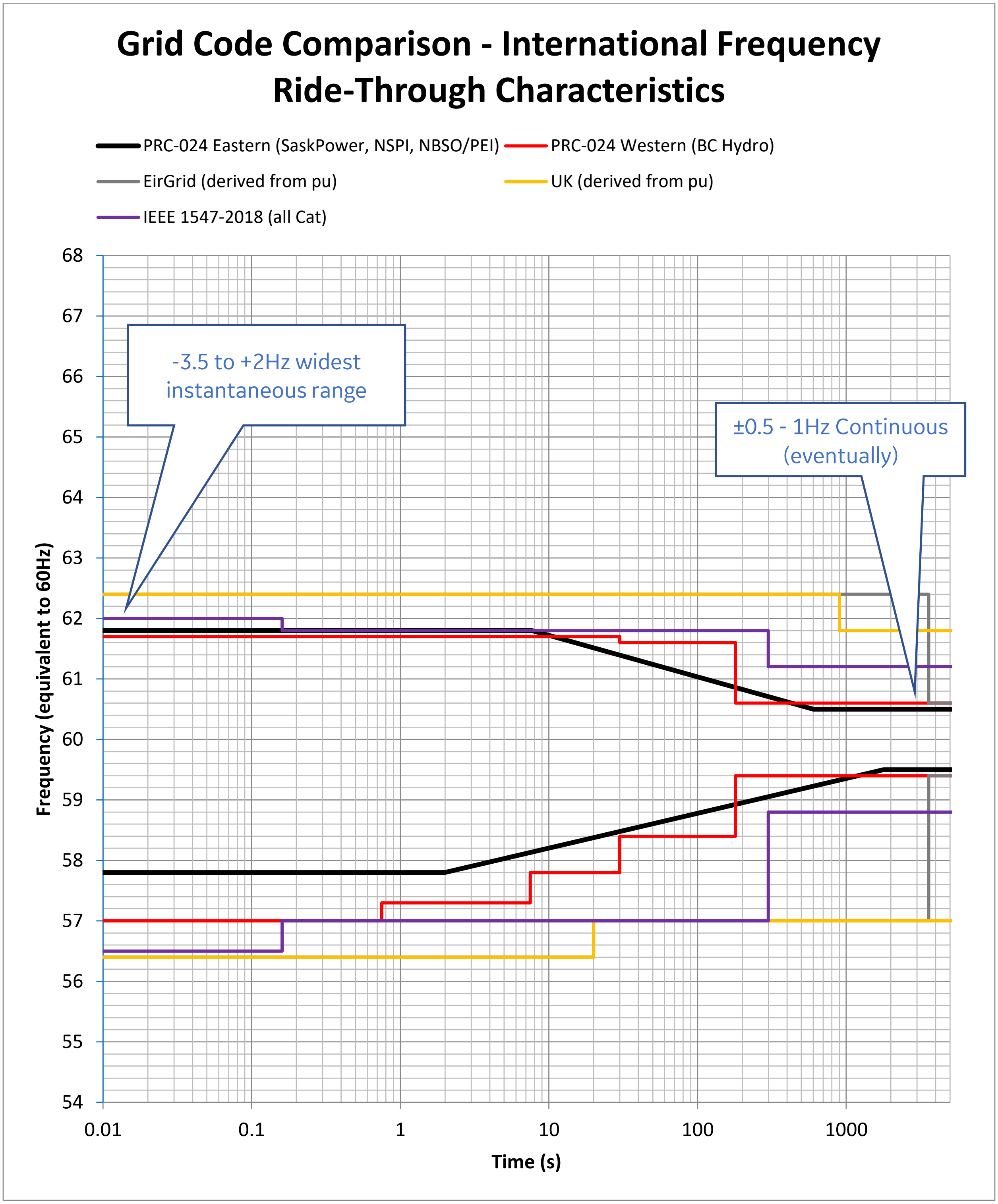


Figure 20: Comparison of frequency ride through requirements outside of Canada

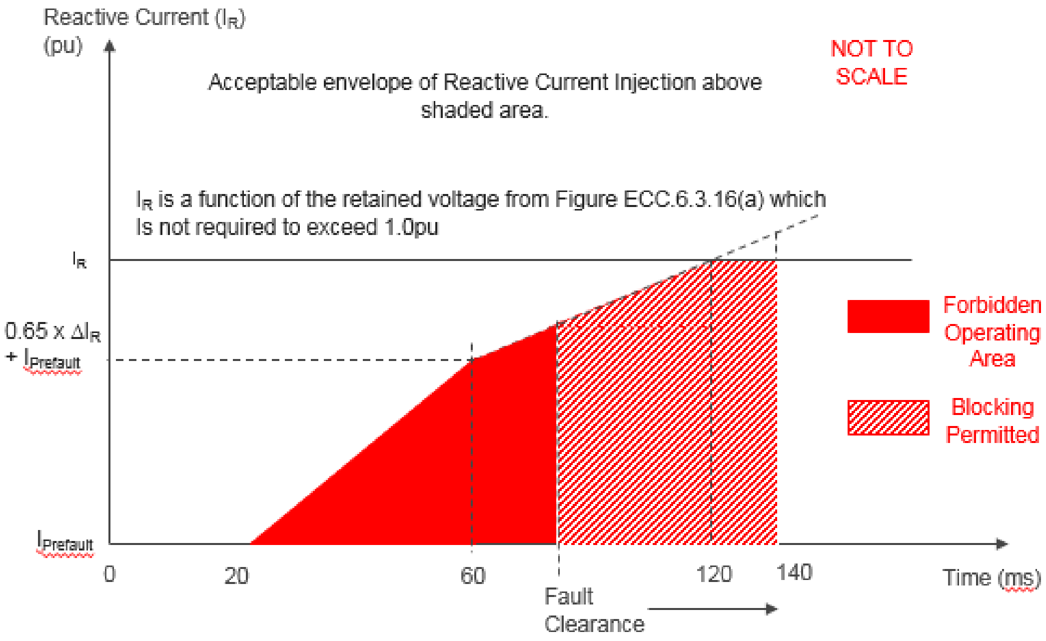


Figure 21: EIRGRID reactive current injection during disturbances

Table 19: Global large-signal stability requirements

Grid Code Requirement	Summary
Momentary Cessation	Not allowed in US per NERC, TX and CA. Must be modeled in GB.
Phase jump immunity including phase-locked loop ride-through	Inverter tripping due to phase jumps not allowed in NERC, TX, CA.
Return to Service Following Tripping	Based on BA reconnection requirements: NERC, TX, CA Reconnect when network is restored: IE SPS for timely restoration after faults: GB
Anti-Islanding protection and island mode operation	Avoid Islanding: AU, GB Avoid islanding due to UFLS due to PRC-006, UL1741, IEEE1547 in US.
Inverter current injection during faults	Specific requirements per region. All regions required to support real/reactive current to maintain grid stability.

4.7 Small Signal Stability & Damping

Capability to provide power swing damping via power system stabilizer is generally required on synchronous machines everywhere. Power oscillation damping may be required on wind plants in Ireland and Australia. There are specific requirements to evaluate and avoid SSR and SSCI in GB. In Texas, EMT models are required from the generator owner to evaluate the risk of sub-synchronous control interaction between IBR in weak and series compensated networks.

A summary of global small signal stability and damping requirements may be found in Table 20.

Table 20: Global small signal stability and damping requirements

Grid Code Requirement	Summary
Power System Stabilizer	Generally required on Synchronous Machines in IE, AU, GB, NERC, TX and CA. May be required on wind plants in IE.
Power System Damping and small signal stability	PSS required or capable for all regions on Synch generation. Damping requirements set in AU for wind generation.
Sub-synchronous resonance (SSR) and Sub-synchronous control interaction (SSCI)	Specific SSO/SSR/SSCI requirements in GB (via IA). TX requires EMT models for SSCI evaluation. NERC Reliability Guideline recommends EMT evaluation to assess SSO risk.

4.8 Modeling & Data

Modeling and data reporting requirements vary widely by region. Generally, modeling requirements are extensive and explicit and include provision and validation of positive-sequence fundamental-frequency and EMT models. There is an extensive validation and certification process in Europe and Australia to assure simulation models match as-installed equipment, and that those as-installed models meet the requirements of the grid code. Generally, there are also requirements for monitoring & data reporting in all locations that specify voltage, frequency, real and reactive power and status monitoring. Wind forecasting monitoring and data is required in Great Britain and wind and solar monitoring and data is required in Texas and California.

A summary of global modeling and data requirements may be found in Table 21.

Table 21: Global modeling & data requirements

Grid Code Requirement	Summary
Data Reporting	Specific to each region. Data Reporting called out in IE, GB, NERC, TX and CA.
Modeling	Modeling and Validation generally required, more extensive validation requirements in IE, AU and GB.
Monitoring & Data Reporting Requirements	Specific requirements per region. Generally, voltage, frequency, P/Q and status monitoring required in all regions.
Generator Forecast	Real-time Wind Forecast: GB Day-Ahead/Hour-Ahead Wind & Solar Forecasts: TX & CA
Measured Meteorological data reporting	Wind speed, direction, irradiance, barometric pressure: TX and CA. Real time wind data: GB

4.9 High IBR Penetration

There is great and growing interest globally to update codes and requirements to address new system needs and technologies to accommodate higher penetration of IBR. As penetration of IBR grows and displaces synchronous machines, grids get weaker and it becomes increasingly difficult to maintain stability between controls and across the network. The next section talks extensively about the issues and possible new technologies to resolve them. There is a consensus that codes need to rapidly evolve to accommodate these needs. Practices in many jurisdictions today address screening techniques and detailed modeling methods to predict when interactions and instabilities will occur. NERC, through the Inverter-based Resource Performance Task Force, has established many reliability guidelines for inverter-based resources[4], how new requirements should evolve to accommodate them[5] and specific practices to evaluate risks of weak grid connection[6]. These guidelines offer the best guidance regarding evaluation and integration methodology for detecting and mitigating control and network instability due to weak grids.

Grid forming resources is a new technology that utilizes control methodology to avoid control interactions and support grid needs with high penetration of IBRs. This new technology is discussed in detail in the next section, in conjunction with battery energy storage. Today, grid codes have not evolved to specifically address this type of control methodology, except for a proposed set of requirements under review by National Grid ESO in Great Britain. The GC0137 drafting team has drafted a proposed requirement called 'Minimum Specification Required for Provision of GB Grid Forming Capability'[7].

Various metrics may be used to assess risks due to weak grid and short circuit ratio. These metrics and their application are shown in Figure 22. If the result of these calculations reveals a low ratio, EMT modeling is highly recommended to determine the risk of instability or interaction. This is a best practice that should be considered in grid codes for screening interconnection risk of GFL resources. More details about how to perform the calculations may be found in the reliability guideline.

Figure 23 shows a summary of capabilities from four resources to provide essential grid services, particularly when IBR penetration increases. These resources include a synchronous machine, a grid forming inverter following the definition of GC0137 (GBGFC), a virtual synchronous machine with zero inertia (VSM0H) and a conventional GFL converter. All resources can provide essential services but the GBGFC control, as defined, may support the grid in the closest manner to a synchronous machine. The requirements outlined in the GC0137 proposed code cover very specific needs to the UK grid and while the functionality is useful elsewhere, specific quantities recommended in this draft standard likely need to be adjusted to be useful in other areas.

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[4] NERC IRPWG Reliability Guideline on Inverter-based Resource Performance, September, 2018, https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Inverter-Based_Resource_Performance_Guideline.pdf

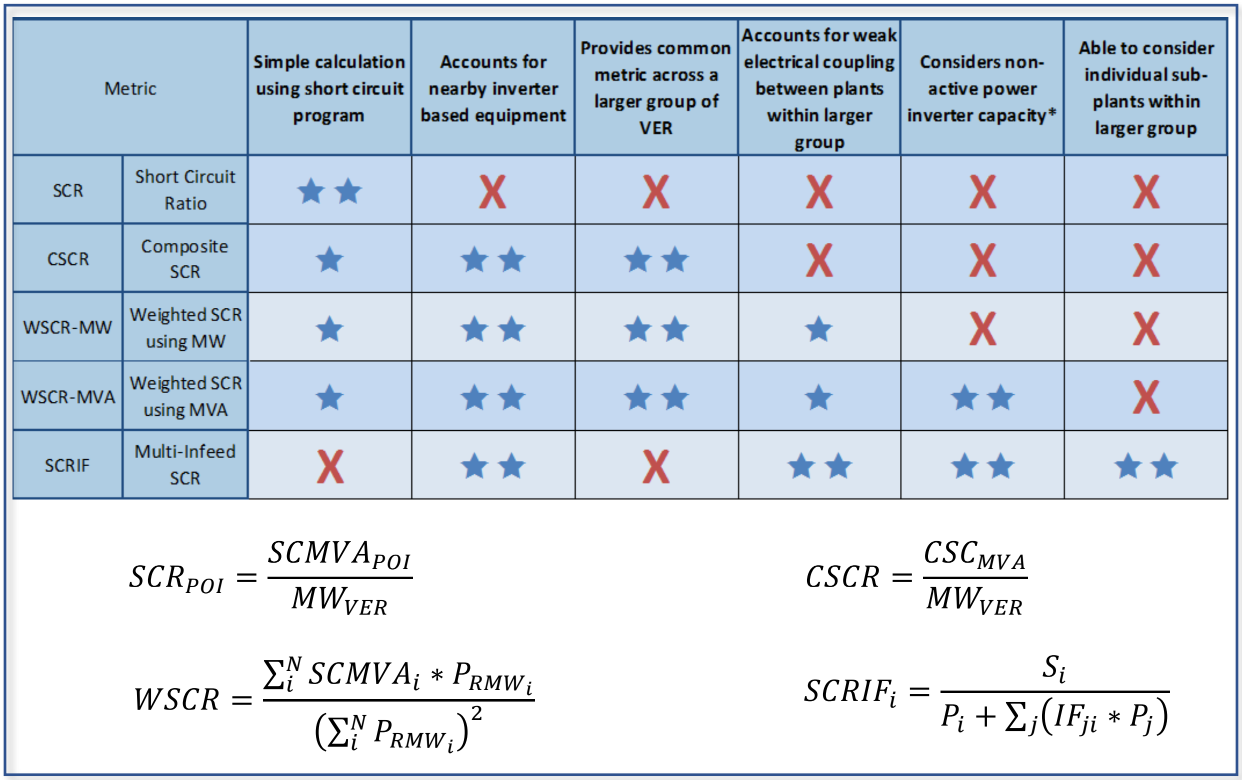
[5] NERC IRPWG Reliability Guideline on Improvements to Interconnection Requirements to IBRs, September, 2019, https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability_Guideline_IBR_Interconnection_Requirements_Improvements.pdf

[6] NERC Reliability Guideline on Integrating Variable Energy Resources into Weak Power Systems, July, 2017 https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf

[7] Minimum Specification Required for Provision of GB Grid Forming Capability https://www.nationalgrideso.com/industry-information/codes/grid-code-old/modifications/gc0137-minimum-specification-required

Table 22: Global requirements addressing grid needs for high IBR penetration

Grid Code Requirement	Summary
Control stability, control interactions & weak grid connection	No specific requirements but practices in TX and NERC identify when EMT models are needed to assess control stability risk via SCR metrics.
Grid Forming Controls	Initial requirements being formed in GB (GC0137). NERC, ESIG and GPST also developing definitions and identifying system needs/control functions of Grid Forming.
Battery Energy Storage Requirements	Automatic low frequency disconnection in GB. NERC Reliability Guideline on Hybrid power plants and ES. Distributed storage shall not be connected to circuits subject to UFLS disconnection in TX.



Metric		Simple calculation using short circuit program	Accounts for nearby inverter based equipment	Provides common metric across a larger group of VER	Accounts for weak electrical coupling between plants within larger group	Considers non-active power inverter capacity*	Able to consider individual sub-plants within larger group
SCR	Short Circuit Ratio	★★	X	X	X	X	X
CSCR	Composite SCR	★	★★	★★	X	X	X
WSCR-MW	Weighted SCR using MW	★	★★	★★	★	X	X
WSCR-MVA	Weighted SCR using MVA	★	★★	★★	★	★★	X
SCRIF	Multi-Infeed SCR	X	★★	X	★★	★★	★★

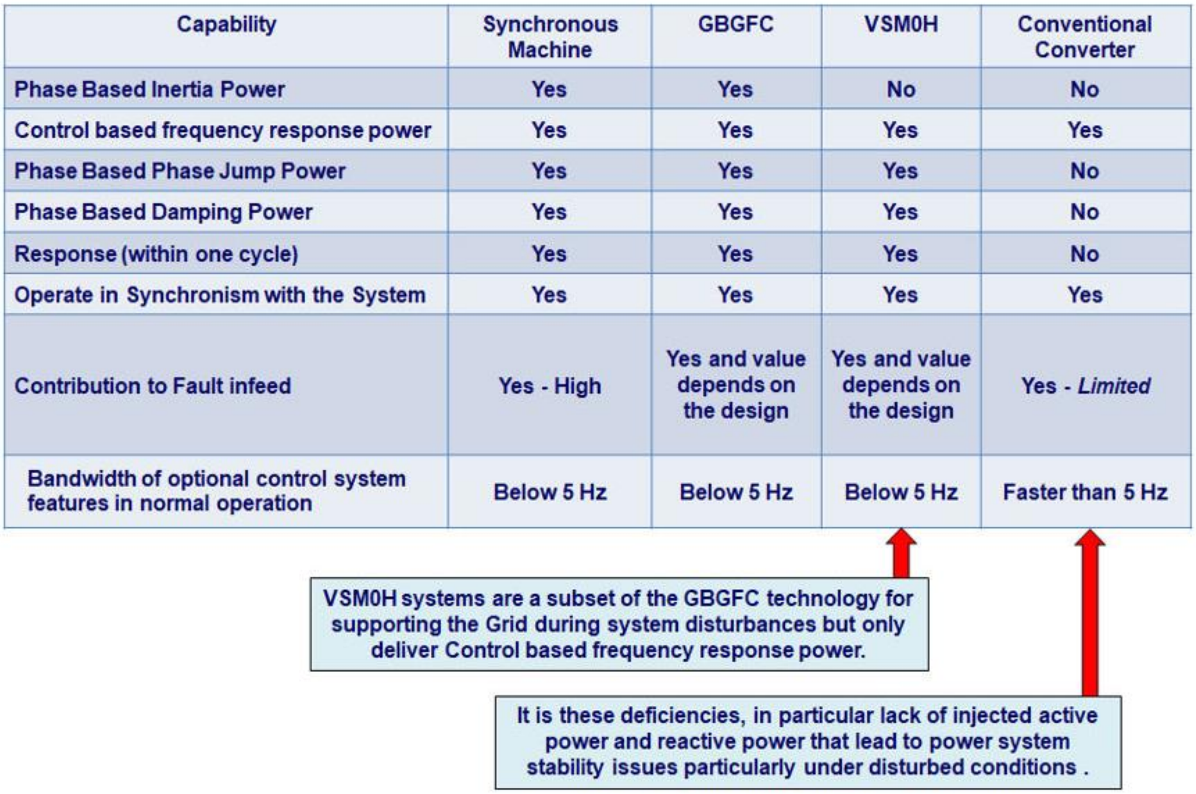
$$SCR_{POI} = \frac{SCMVA_{POI}}{MW_{VER}}$$

$$CSCR = \frac{CSC_{MVA}}{MW_{VER}}$$

$$WSCR = \frac{\sum_i^N SCMVA_i * P_{RMW_i}}{\left(\sum_i^N P_{RMW_i}\right)^2}$$

$$SCRIF_i = \frac{S_i}{P_i + \sum_j \left(IF_{ji} * P_j\right)}$$

Figure 22: Comparison of metrics to determine weak grid risk and types of models to use (courtesy NERC Reliability Guideline)



Capability	Synchronous Machine	GBGFC	VSM0H	Conventional Converter
Phase Based Inertia Power	Yes	Yes	No	No
Control based frequency response power	Yes	Yes	Yes	Yes
Phase Based Phase Jump Power	Yes	Yes	Yes	No
Phase Based Damping Power	Yes	Yes	Yes	No
Response (within one cycle)	Yes	Yes	Yes	No
Operate in Synchronism with the System	Yes	Yes	Yes	Yes
Contribution to Fault infeed	Yes - High	Yes and value depends on the design	Yes and value depends on the design	Yes - *Limited*
Bandwidth of optional control system features in normal operation	Below 5 Hz	Below 5 Hz	Below 5 Hz	Faster than 5 Hz

VSM0H systems are a subset of the GBGFC technology for supporting the Grid during system disturbances but only deliver Control based frequency response power.

It is these deficiencies, in particular lack of injected active power and reactive power that lead to power system stability issues particularly under disturbed conditions .

Figure 23: National Grid ESO GC0137 Grid Forming Definitions

5 CONSIDERATIONS AND RECOMMENDATIONS FOR FUTURE CANADIAN PROVINCIAL GRID CODES

This section outlines a set of recommendations to account for latest needs in grid codes and interconnection requirements to minimize grid reliability risks, maximize benefit of technology and performance from every asset and harmonize requirements across Canada. These recommendations are consistent with and largely reflect contents of the latest industry practice and latest NERC reliability guidelines referenced on previous pages. Additional recommendations on modeling, DER impact, ancillary services market mechanisms and integrated planning are found in later sections of this report.

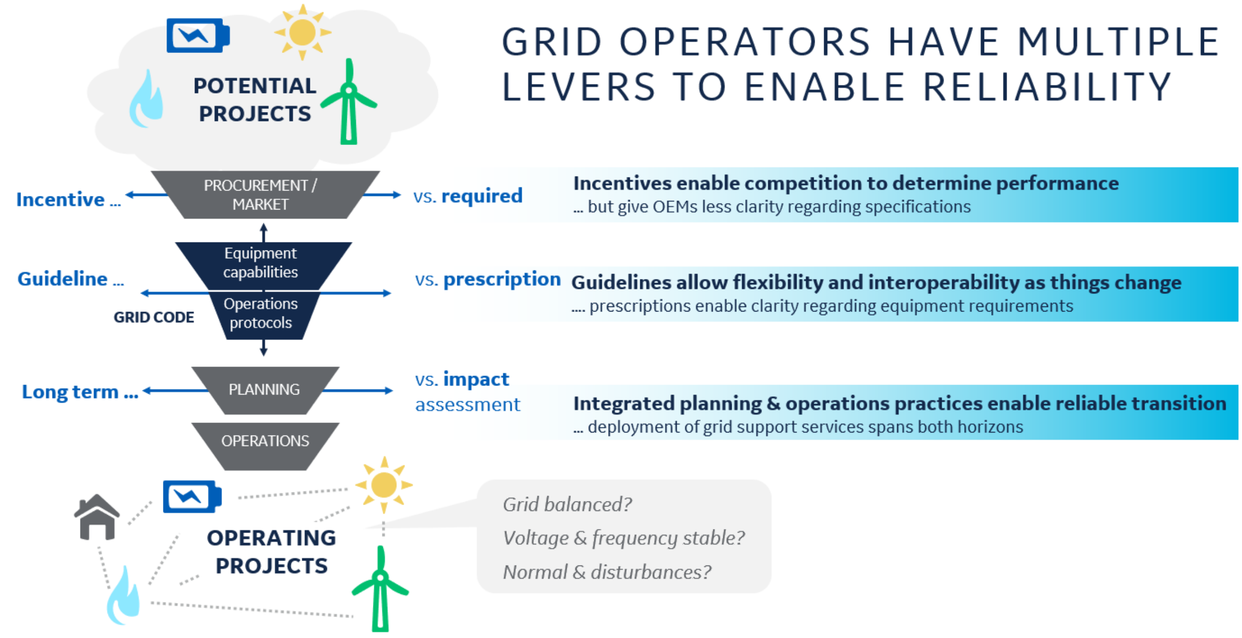
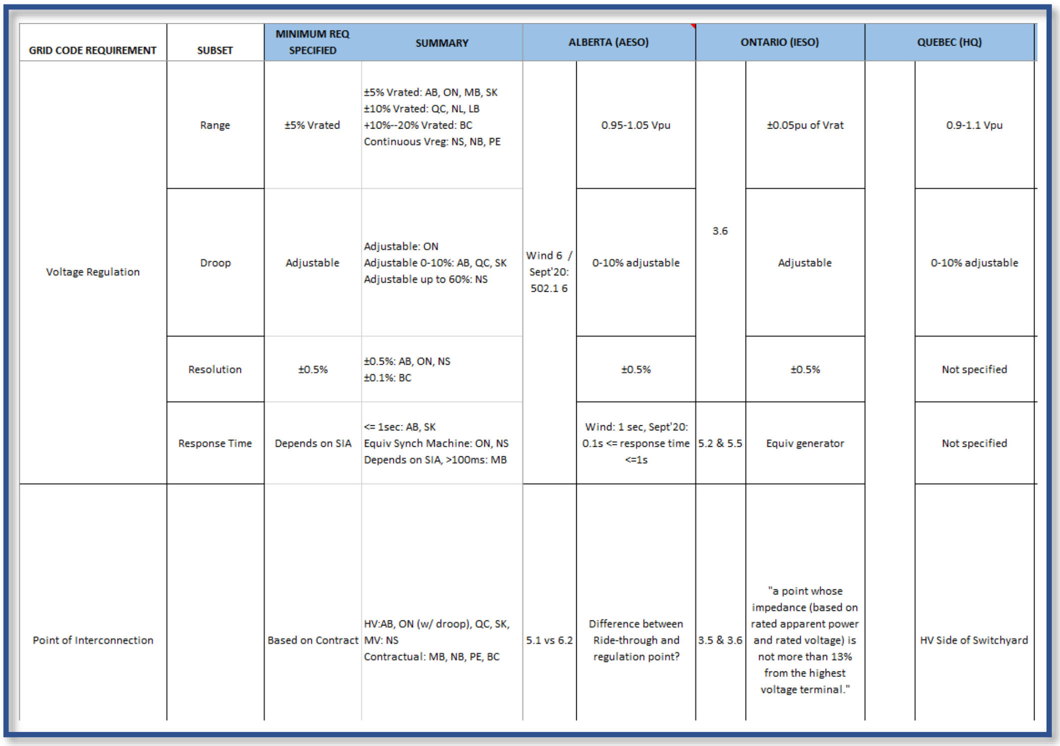


Figure 24: Tradeoffs for harmonizing grid requirements

General recommendations

When developing and harmonizing system-level integration standards or grid codes, there should be a balance among the needs of grid operators for reliable service, the needs of customers for minimal costs, and the needs of society for a sustainable future, as Figure 24 points out. Requirements should be no more specific than they need to be to avoid over-designed equipment and reduced efficiency but should be specific enough to maintain adequate system reliability. All three of these needs are rapidly changing. Market design and system requirements should promote performance needs so that any provider using any technology can support the grid on an equal cost-sensitive playing field. To the extent possible, maintaining a single code that neutrally addresses all technologies is preferable. However, performance and attributes that are specific to a technology or class of resource (e.g. synchronous machines or inverter-based resources) may be addressed in dedicated sections of each code, as needed.

Create and maintain a common form or **“Application Guide”** for requirements across Canada. The application guide is a spreadsheet that compares requirements across the provinces and is included with this project. It may be used to compare requirements and, together with the recommendations in this report, may be updated to track the iterations on grid codes and interconnection requirements. A sample of this application guide is seen in Figure 25. A form may be used to collect information on a periodic (e.g. annual) basis from all grid operators to track updates to requirements. An example form is included with this report in Appendix A.



GRID CODE REQUIREMENT	SUBSET	MINIMUM REQ SPECIFIED	SUMMARY	ALBERTA (AESO)		ONTARIO (IESO)		QUEBEC (HQ)	
Voltage Regulation	Range	±5% Vrated	±5% Vrated: AB, ON, MB, SK ±10% Vrated: QC, NL, LB +10%--20% Vrated: BC Continuous Vreg: NS, NB, PE	Wind 6 / Sept'20: 502.1 6	0.95-1.05 Vpu	3.6	±0.05pu of Vrat		0.9-1.1 Vpu
	Droop	Adjustable	Adjustable: ON Adjustable 0-10%: AB, QC, SK Adjustable up to 60%: NS		0-10% adjustable		Adjustable		0-10% adjustable
	Resolution	±0.5%	±0.5%: AB, ON, NS ±0.1%: BC		±0.5%		±0.5%		Not specified
	Response Time	Depends on SIA	<= 1sec: AB, SK Equiv Synch Machine: ON, NS Depends on SIA, >100ms: MB		Wind: 1 sec, Sept'20: 0.1s <= response time <=1s	5.2 & 5.5	Equiv generator		Not specified
Point of Interconnection		Based on Contract	HV:AB, ON (w/ droop), QC, SK, MV: NS Contractual: MB, NB, PE, BC	5.1 vs 6.2	Difference between Ride-through and regulation point?	3.5 & 3.6	"a point whose impedance (based on rated apparent power and rated voltage) is not more than 13% from the highest voltage terminal."		HV Side of Switchyard

Figure 25: Sample portion of Canadian Grid Code Harmonization Application Guide

Appropriate modeling of load using the latest composite load models representing explicit DER behavior (u-DER and r-DER) should be used in grid analyses. These models should be validated against recorded field events and data collected from each utility regarding the composition of DER resources (type, location, aggregation, etc.).

Every inverter-based resource should be **equipped with the capability for high-resolution data recording** to sufficiently capture voltage and current waveforms during any fault or large grid disturbance. High-resolution data should also be captured at the plant high voltage grid connection and medium voltage with a digital fault recorder or plant controller. IEEE P.2800[8] Table 2, at the time this report was published, recommends that, at a minimum, measurements of 3-phase fundamental frequency voltage, current and derived frequency be captured via transient measurements at the inverter-based resource unit, Plant and supplementary support devices at the point of connection. The draft standard recommends that voltage, current and frequency measurement accuracy,

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[8] "IEEE Draft Standard for Interconnection and Interoperability of Inverter-Based Resources (IBR) Interconnecting with Associated Transmission Electric Power Systems," in IEEE P2800/D6.0, March 2021 , vol., no., pp.1-170, 11 March 2021. https://ieeexplore.ieee.org/document/9416323

measurement window and sampling rate. Note that IEEE P.2800, at the time this report is published, is in the drafting cycle and is subject to change. Time stamped sequence of events recorder logs should be available at all voltage levels within the plant and should have at least 1ms resolution to support analysis of disturbance events. Typical high-speed disturbance data recorded during large grid disturbances (faults) is 1-2 seconds in duration, limited by the memory storage capability of the equipment to store data files. It is recommended to follow IEEE P2800 regarding transient event recording upon publication of the standard.

Frequency stability and support

Inverter-based resources should have the capability of providing **Fast Frequency Response (FFR) and Primary Frequency Response (PFR)** with an adjustable droop range and tunable control characteristics.

IEEE P.2800[8 above] Sections 6.1 and 6.2, at the time this report was published, specifies performance requirements for PFR and FFR in inverter-based resources. In summary, the draft standard recommends that primary frequency response shall include the capability to respond to under-frequency disturbances (by active power increase) and over-frequency disturbances (by active power decrease). The PFR controller should have fixed droop characteristics with default values. It should be possible to set different level of droop for over- and under-frequency conditions. Frequency droop settings should have constant droop slopes. Primary frequency response characteristics are specified where over/under frequency deadband and droop slope should be adjustable within a range in Figure 9 and Table 9 of the standard. The standard also recommends maximum, minimum and default values for PFR reaction time, rise time, settling time, damping ratio and settling band in Table 10 of the standard.

For FFR, response characteristics are specified by parameters in Table 12 of the standard from non-wind IBR for under-frequency trigger and droop setting. FFR from wind turbines is also specifically addressed to define the minimum active power injection and duration, settling characteristics and decrease in power to for recovery and energy payback. The standard also addresses multiple successive FFR event capability and coordination with PFR functionality. Note that IEEE P.2800, at the time this report is published, is in the drafting cycle and is subject to change. It is recommended to follow IEEE P2800 regarding PFR and FFR performance for IBRs upon publication of the standard.

Large signal stability and performance during disturbances

Inverters should avoid using protection settings that trip or block output due to **instantaneous frequency excursions or phase-jumps**. Adding sufficient time delay to inverter frequency tripping that will allow the inverter to ride-through the transient event and distorted waveform is recommended.

New inverters should not **momentarily block or cease current injection** for disturbances with voltage profiles within the required time-voltage envelope set in the voltage ride-through requirement for grids above a minimum prescribed cSCR level (e.g. 3.0). Existing inverters should be configured to not momentarily block or cease current injection outside of continuous operating range unless equipment damage would result from excessive DC or AC voltage or AC overcurrent. The inverter should manage the transition of real and reactive current during and after the disturbance as needed to support ride-through, grid stability and voltage recovery. If the inverters must momentarily block some or all current injection to avoid permanent equipment damage during the transient outside of the expected operating range set in the ride-through requirements, they should be configured to restore active current output with a delay no greater than what is needed to maintain grid stability (typically no greater than 0.5-1sec). Weak grids may exacerbate transient voltage levels and phase angle excursions during large disturbances. Active power reduction, slower response and recovery in weak grid environments should be expected and allowed to avoid control instabilities and voltage collapse. Momentary cessation during short term transient over-voltage conditions above 120% -180% nominal voltage should be allowed per IEEE P2800.

Existing inverters where **momentary cessation** cannot be eliminated should not be impeded from restoring current injection following a momentary cessation by plant-level ramp rates meant for operational adjustments. The inverter should recover active power injection quickly and stably, commensurate with the grid strength and fault type and duration to maintain grid stability and avoid a voltage collapse. In low short-circuit level (weak) grids with higher penetration of inverter-based resources (say, below 3.0 SCR), EMT analysis may be necessary to determine appropriate current injection and active current recovery characteristics.

Inverter voltage **protection should be set based on physical equipment and stability limitations** and not set to trip based on any time-voltage ride-through curve. IEEE P2800[8 above] draft specifies voltage performance criteria and ride through performance during disturbances, including transient performance in the first 15 cycles of an electrical fault. It is recommended to follow these specifications for voltage regulation, equipment protection and ride-through.

Inverter **protective functions should use an appropriately filtered voltage input** for overvoltage protection (e.g. assessing fundamental frequency voltage) when compared to time-voltage ride-through curves to avoid mis-operation during grid disturbances.

Inverters should not trip due to PLL loss of synchronism caused by waveform distortion or phase jumps caused by switching or large disturbances. Please note that this PLL loss of synchronism due to phase jumps should not be confused with an appropriate protection action to quickly reduce active power in weak grid situations to avoid grid instability. The latter is not a loss of synchronism fault; rather an intended protection action to maintain grid stability and plant recovery in low SCR grids and should be allowed. Such protection action is implemented in the inverter (vs. plant protection or control) and may result in partial tripping or blocking to avoid instability; a favorable and desired characteristic.

DC reverse current detection and protection should be coordinated to avoid tripping for DC reverse currents that result from high-frequency transients that will not pose risk of equipment damage.

Collector system design and **ride-through capability** should account for voltage drop and reactive loss/gain across the collector network to appropriately assess compliance with plant-level ride through requirements. Also, **grid codes should clearly state the measurement point (e.g. Point of Interconnection) and measurement quantity (e.g. positive sequence voltage of a single phase) when specifying ride-through curves. Additionally, the following aspects on ride-through are recommended:**

- NERC PRC-024 should be considered a minimum requirement.
- Given the varying characteristics of each province's grid, a general recommendation can be made for each province to specify an "envelope" curve which stipulates the extreme limits of expected

voltage excursions, similar to Manitoba Hydro's approach, if PRC-024 is deemed insufficient. This provides the framework for requiring additional ride-through capability above and beyond the NERC PRC-024 characteristic. It is expected that each province will prefer to shape its own requirements, and the envelope concept allows flexibility for this while also providing a common, constructive framework.

- When specifying a VRT curve, it is recommended that the initial HVRT transient should be clearly bounded and defined, similar to how IEEE P2800 manages this issue. The P2800 standard addresses transient overvoltage ride-through by stating that all IBR plants shall be capable to ride-through the higher of each phase-phase or phase-ground instantaneous voltages up to 180% for 1.6ms. During the transient period up to 15ms, momentary cessation is allowed above 120% V_{POM}.
- Regarding validation of VRT compliance, the following methodology is suggested:
    - A simplified model can be constructed of the windfarm, with the utility connection modeled by a voltage source connected to the windfarm POI through a Thevenin equivalent impedance. The model should include aggregation of the machines and collector system equivalencing techniques commonly performed in the industry.
    - The dynamic model of the windfarm should be based on a typical configuration, including its protection characteristics.
    - A so-called voltage "playback" function can be used to the model the voltage source dynamics. Pass/fail criteria is simply whether the windfarm generator rides through or trips.
    - IMPORTANT: the playback function should ONLY be used to evaluate compliance with the ride-through characteristic. It should NOT be used to assess dynamic behavior of the machines or of the plant controller, given that the playback function allows the user to operate the model in an open-loop fashion, which is not a realistic operating condition.

AC overcurrent, DC and AC overvoltage protection should be explicitly included in ride-through standards where tripping on these elements shall not occur for credible disturbances with voltage profiles within the specified ride-through time-voltage curves.

Small signal stability & damping

Plant developers and owners should screen plant interconnection design for **TOV, shunt resonance and other high-frequency phenomena** caused by MV-connected shunt compensation, selection and layout of buried collector system cable, transformer saturation and capacitive coupling, etc. Insulation coordination and appropriate grounding analysis should also be performed. EMT modeling is commonly needed to assess the risk and mitigation measures for this phenomenon.

Use screening criteria to classify **grid strength through metrics of SCR, cSCR, WSCR and SCRIF**, as recommended by the NERC Reliability Guideline to Integrate VER into Weak Power Systems (2017), to determine when EMT modeling is necessary to assess risk of control interaction or stability issues due to weak power grids. If the SCR is below the recommended values in the guideline, more detailed EMT modeling is recommended to appropriately assess and address stability risk.

High IBR Penetration Technologies

Grid Forming Controls (GFM) are a relatively new and recently commercialized technology designed to mitigate certain attributes of stability due to high penetration of inverter-based resources. Today's fleet of installed commercial IBRs deploy grid following (GFL) controls. That is, the inverter or converter injects real and reactive current into the grid at a phase angle relative to the grid voltage, within the limits of equipment capabilities. It does this most typically through a phase-lock-loop (PLL) control, where the voltage waveform is measured and current waveform is injected via switched-mode power electronic control at a phase angle suitable to deliver power with the given grid condition. Grid following controls need an existing grid to work; they cannot form or black start the grid on their own. As mentioned above, grid following controls also have limitations for stability in weak grid conditions. That is, they are susceptible to various modes of instability and tripping in grids with low short circuit ratios. The following **Weak Grid Risks and Failure Modes** should be screened and evaluated with EMT models when composite or weighted short circuit ratio (cSCR or wSCR) at the POI is low (e.g. cSCR<3) upon interconnection of GFL inverter-based resources:

- **Failure to ride through disturbances:** Weak systems make ride-through more difficult, especially following a network disturbance, leading to wider system issues, such as under-frequency or loss of voltage support
- **Converter control interactions:** The weaker the interconnection, the more likely controls will be to influence each other and interact negatively with each other
- **Converter control instability:** If the network is weak enough, controls may enter unstable region with no external influence needed (small signal instability)
- **Cycling between converter control modes:** For example**,** If system is weak, various wind turbine control modes may cycle multiple times as the wind turbine attempts recovery, introducing severe transients into the system. Similar concerns for other converters (e.g. solar or battery) exists.
- **Steady-State Voltage Collapse:** Voltage collapses more sensitively as real & reactive power flows through weak grid (non-source dependent)

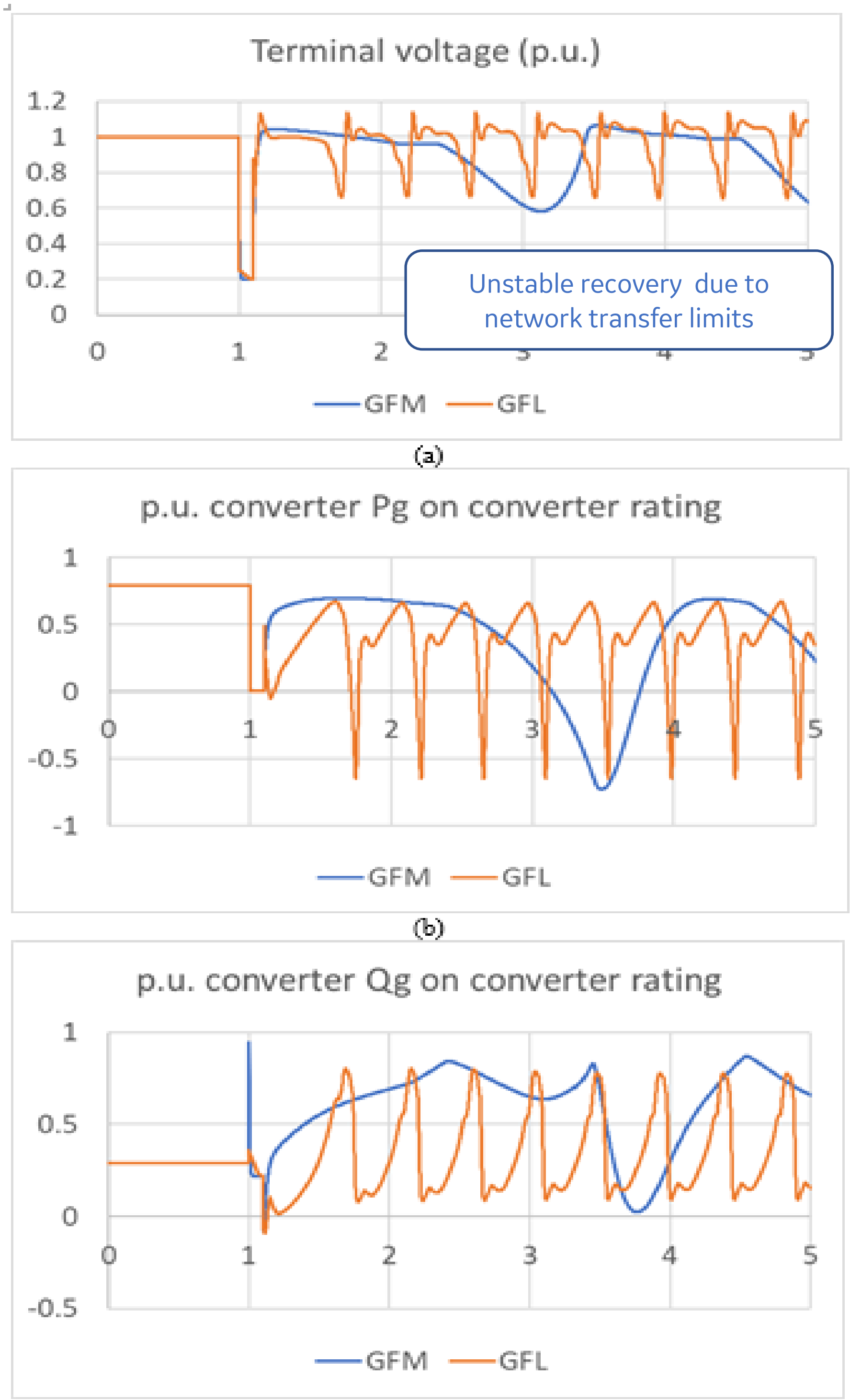
GFM controls do not require an established grid to operate. GFM is a class of controls, most often utilizing a voltage-regulated voltage source converter, that acts similar to a synchronous machine in that it behaves as a voltage source within the limits of its power electronic controls. Their primary objective is to maintain an internal voltage phasor. This phasor may be held constant to perform black start functionality or may follow a grid reference to maintain synchronism with other resources when connected to the bulk grid. There are many types of grid forming control, all subject to physical and control constraints including voltage, current and energy limits as well as system level power transfer limits. If the controls are set to mimic all aspects of a synchronous machine (e.g. excitation, inertial response, short circuit behavior, etc.), it is classified as a virtual synchronous machine. The objectives of the GFM control do not necessarily have to mimic all aspects of a synchronous machine, but their general nature make the resource behave as a Thevenin source. With sufficient energy buffer, they could potentially reduce the minimum inertia requirements that the grid needs (derived from synchronous machines) for secure power system operation and allow restoration in the event of blackout. GFM converters are also less susceptible to sub- and super- synchronous frequency control interactions even under weak grid conditions.

While there are many ways GFM controls may be implemented, they generally can support grid needs in the following ways:

- **Maintain control stability** at low or zero short circuit ratio (such as the case with black start). This allows these resources to operate in very weak grids without losing control stability. GFM controls may also provide enhanced phase-jump immunity and ride through capability since the controls are not bound by PLL stability. These controls make the system stronger by slowing down angle variations in system voltage, with a response similar to a synchronous machine without the swing dynamics or physical rotor angle stability limits.
- **Support frequency and inertia during grid disturbances**. Depending on control design, arresting energy may be provided by GFM sources to maintain frequency stability and support containment and restoration upon loss of generation or system separation.
- **Maintain voltage and angular stability** without limitations due to rotor angle, critical clearing time and transient stability common to synchronous machines.
- If coupled with an energy source such as **battery energy storage, GFM resources may provide black start and restoration services**. There are now commercially available GFM battery solutions providing black start capability to heavy-duty gas fired power plants in the USA and Europe. This proven technology not only can provide black start and system restoration services but also augment other grid support needs.

While GFM controls offer many benefits over GFL controls, they still don’t resolve all issues relative to weak grids or high IBR penetration. While GFM can maintain stable controls in weak grids, there is still a power transfer limitation associated with high impedance networks. Voltage collapse will still occur if power is pushed through a high-impedance and long-distance transmission path if unsupported. This type of voltage instability would happen even if power is sourced from a synchronous machine. The limitation is of the network circuit and not the source. However, as more GFM resources are integrated, rotor angle stability limitations become less prevalent, but they are displaced by network angular stability concerns that could still cause a grid collapse. Dynamic reactive support from Synchronous Condensers and FACTS across a high impedance path will help to a degree to support the voltage but are still subject to more severe changes in grid voltage, given changes in real and reactive power in these paths.

Figure 26 (a) though (c) shows the voltages, real and reactive power at the converter terminal for an example simulation case with power being transferred over a long line upon recovery of a disturbance. Both GFM and GFL IBR plants recover in a different manner but both are unstable due to network limitations to transfer power. In this scenario, even though the controls were stable, such network instability would trip the resource or cause tripping of other equipment. In this example, power sourced from a synchronous machine would exhibit similar network instability as the GFM source.



Unstable recovery due to network transfer limits

(a)

(b)

(c)

Figure 26: GFM vs. GFL behavior during recovery into high impedance network[9]

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[9] Rao, SD; Dutta, S., Lwin, M., Howard, D., Konopinski, R., Achilles, S., MacDowell, J, "Grid-forming Inverters – Real-life Implementation and Lessons Learned", IET 9th International Conference on Renewable Power Generation, March 2021

Grid forming resources are just beginning to be widely commercially available and the industry (OEMs, grid operators, equipment owners) are rapidly learning how to enable and deploy this technology. Grid forming capabilities in battery energy storage has been proven through several projects to support black start services. Grid forming controls in wind turbines and solar inverters is still largely being developed by manufacturers, and some early-adoption pilot projects in Europe exist. This new technology deployment is very much a chicken-egg issue. Which comes first? The equipment capabilities or the requirements? How do equipment manufacturers design controls and what functionality and behavior is needed? How do grid operators and policy makers know what equipment capabilities are possible to draft new requirements? This is a conundrum that is immensely difficult to solve on its own if specifying the GFM technology itself.

Instead of specifying GFL or GFM technology explicitly, the authors believe it is best and most effective to break this conundrum by specifying system needs as the generation mix evolves to be more inverter-based. Equipment performance may be designed and deployed to cost effectively meet those needs in various ways.

System needs are continuing to evolve as mix and technology evolves. Grid codes should account for the trends in grid needs with high shares of inverter-based technologies, higher integration of DC and AC coupled energy storage and hybrid power plants. They should also account for greater demand for flexibility and visibility to manage the variability and uncertainty of fuel supply from wind and solar resources. Finally, as complexity of the grid grows, it is critical that grid codes account for the interoperability of controls and capabilities between all resources and devices across transmission, distribution and load.

The first step to achieve the above may be taken by considering the following recommendations:

Draft requirements for **battery energy storage** to:

- Have black start capability and operate stably in a very low to zero short circuit ratio environment. This requirement is most deployable when coupled with an ancillary services market mechanism to provide an economic incentive to provide this service.
- Have capability to provide primary and fast frequency response to arrest the decline of frequency after contingencies with performance at least as good as an equivalently rated synchronous machine
- Be rated to provide required services (e.g. frequency response, regulation, peak shifting, etc.) while maintaining state-of-charge

Draft requirements for **all resources** to:

- Have capability to accept and respond to AGC signals.
- Have capability to withstand wider bands of frequency without tripping offline under normal operation and during disturbances since electrical frequency will continue to be more decoupled from machine speed and less indicative of supply-demand balance as IBR penetration grows. As the grid evolves, frequency ride-though curves are expected to evolve.
- Provide reactive power under all operating conditions if the equipment is capable of doing so, including zero active power delivery.
- Have the capability to provide power system stabilizer or power oscillation damping functionality with adjustability of tuning.

- Have adjustable voltage/reactive droop functionality and coordinate volt/var regulator hierarchy to avoid inter-plant and intra-plant interactions and instabilities.
- Have capability to provide primary and fast frequency response with adjustable droop and gain settings.
- Avoid creating instabilities due to control interaction, resonance, electro-mechanical interactions, voltage constraints or angle separation during normal operation or disturbances.
- Upon request from the system operator, have black start capability and operate stably in a very low to zero short circuit ratio environment. This requirement is most deployable when coupled with an ancillary services market mechanism to provide an economic incentive to provide this service.
- Specify capability to enhance operational flexibility from all resources with minimum ramping requirements, fast start-ups, minimum load capability to accommodate variability and uncertainty of net load. These requirements should be a qualifier to, and coupled with, ancillary services market mechanisms to provide an economic incentive for providing these services.

Draft requirements for **Protective Relaying** to:

- Not rely on overcurrent protection if provision of short circuit current for proper coordination, selectivity & security is inadequate.
- Prioritize communications-based differential protection in place of overcurrent protection when practical
- Prioritize communications-based POTT or PUTT distance protection with load encroachment blocking for transmission line protection
- Allow islanding if resources are capable of maintaining voltage and frequency support in low to zero short-circuit ratio environment

Draft requirements to support **integrated planning practices** (per section 9 below) to:

- Have compatibility of data between positive-sequence fundamental-frequency models and electromagnetic transients models to perform stability analysis with higher penetration of IBRs
- Have compatibility for data between positive-sequence fundamental-frequency models and production cost models to allow iterative security constrained economic dispatch and stability assessments

6 IMPACT AND CONSIDERATIONS OF GRID CODES FOR DISTRIBUTED ENERGY RESOURCES

Distributed generation impacts to the bulk electric system continue to grow in importance in many North American jurisdictions as the impact of the penetration of DER (especially PV solar) increases. This impact may manifest in several ways. This section of the report identifies the many ways that DER impacts the bulk transmission grid, outlines some of the risks and practices to identify and mitigate those risks and makes recommendations, where practical, for codes in Canada to address these issues.

6.1 INVERTER CONTROL STABILITY AND LOSS OF SUPPLY EVENTS

Since August 2016, there have been five major events where transmission system faults caused loss of substantial PV solar generation, creating a significant supply deficit to the bulk grid. These transmission faults were all normally cleared events that resulted in the loss of 205MW-1200MW of PV solar generation. These events are described as follows:

- 1200MW fault-induced PV solar interruption due to Blue Cut wildfire on 16 AUG 2016
- 900MW fault-induced PV solar interruption due to Canyon II wildfire on 9 OCT 2017
- 877MW fault-induced PV solar interruption due to Angeles Forest disturbance on 20 APR 2018
- 711MW fault-induced PV solar interruption due to Palmdale Roost disturbance on 11 MAY 2018
- 205MW and 1000MW fault-induced PV solar interruptions due to San Fernando Disturbance on 7 JUL 2020

Based on extensive investigation with equipment manufacturers, plant developers/owners, utility companies and consultants through NERC Inverter-based Resource Performance Task Force and Event Analysis committee, the causes of these events were found to be the following:

- Erroneous instantaneous tripping of some inverters during transient events based on near instantaneous frequency measurements
- Momentary cessation (a temporary blocking of electric current delivery to the power grid) of some PV inverters upon fault inception for voltages outside of +/- 10% of nominal inverter rating. Some inverters exhibited momentary cessation upon fault-induced voltage depression and returned to service at a slow ramp rate over many minutes.
- Ramp rate limits implemented in some plant-level controls caused inverter-based resources to return to service slower than desired following momentary cessation due to a large disturbance. These plant-level ramp rate limits are intended for ramping during normal (undisturbed) operation upon entry or release to a curtailment or operator instruction to balance generation and load. It was found that these limits were also imposed when the voltage recovered sufficiently to a “normal” operating range following a disturbance and restrained the inverters from quickly recovering to pre-disturbance current injection.
- An incorrect Interpretation by some PV solar OEMs of the PRC-024 voltage ride-through protection requirements is that the plant must trip for a disturbance where the voltage exceeds the time-voltage envelope. The correct interpretation of the PRC-024 requirement is that the inverters may trip if needed to avoid equipment damage or inability to remain stable or synchronized.

- Some inverters are configured to trip on instantaneous overvoltage protection, set based on PRC-024 high voltage ride-through characteristics. Any fault or switching-induced high-frequency voltage transients may trip the inverters for a normally-cleared disturbance if such instantaneous voltage protection is used without voltage measurement filtering.
- One inverter manufacturer reported fault codes for PLL synchronization that resulted in protective action to trip the inverter. This PLL synchronization fault may happen as a result of waveform distortion or phase-jumps caused by grid faults or switching events.
- One inverter manufacturer reported fault codes for DC reverse current, which caused inverter tripping and resources to remain offline until they were manually reset.
- In some instances, plants with shunt capacitor banks caused a higher instance of momentary cessation and inverter tripping.
- Implementation of POI-level time-voltage protection curves at the inverter. Due to substantial reactive loss or gains (depending on collector system design and operating point), the terminal voltage profile at each inverter/converter is typically different than at the POI.
- Lack of high-resolution data to capture voltage and current waveforms during and after a disturbance made it extremely difficult to investigate the root cause of some tripping or cessation events.
- Behind-the-meter DER-connected solar exhibited characteristics of momentary cessation and tripping due to bulk-transmission disturbances based on SCADA analysis. For some events, an increase in net load of 100MW-130MW was observed.
- During the latest event, three causes of tripping have been identified: 1) AC overcurrent protection 2) DC low voltage protection and 3) AC low voltage protection. While these events were not explicitly captured in PRC-024, all resulting inverter tripping was considered abnormal since this disturbance was a normally-cleared fault with no resources disconnected as a result of isolation of faulted elements.

6.2 ROLE OF CODES AND STANDARDS IN PROMOTING FORECASTING METHODS THAT PROPERLY ACCOUNT FOR DER GROWTH AND IMPACT

Forecasting distributed energy resources (DER) has proven to be a difficult task, as the behind-the-meter nature of DER inherently nets out system load, making it difficult for planning entities such is ISOs and utilities to accurately predict their respective future loads with accuracy. More specifically, DER operation and promulgation within a given community is generally not visible to system operators, at least by traditional forecasting standards, which thereby increases the uncertainty in the status of system-wide supply and demand that system operators must deal with. Due to these difficulties in netting out DER when forecasting load, system operators often find that their forecasts have under-estimated or over-estimated generation requirements to meet their system's load. Additionally, as DER are mostly non-dispatchable assets for system operators, they do not effectively contribute to the controllable balancing capabilities of supply and demand within the system. Facility forecasts can create major headaches for system operators, not to mention bring about tremendous financial costs. One study performed for the U.S. DOE's Grid Modernization Laboratory Consortium estimates that it would cost approximately $70 million from severe under-forecasting of DERs and approximately $20 million from severe over-forecasting of DERs for a utility with sales of more than 10 TWh per year and with up to 8.5% of sales from distributed PV by the end of a 15-year period.[10]

Traditionally, system operators perform load forecasting tasks utilizing historical trends via observing historical metering at the substation-level. As stated above, this method utilizes analyzing net load, which often gives an under-representation of true load because it masks the load that DER is meeting behind-the-meter. Therefore, system operators are being forced to adapt and utilize new DER forecasting methodologies like customer adoption modeling. This type of modeling focuses on forecasting load from the top down, e.g., separately forecasting load and total quantity of DER at the system-level and then allocating the system DER forecast down to more granular, often area code-specific levels. This allocation is based on many "customer-specific" factors including cost and performance of DER, state- and local-level incentives, customer retail rates, peer effects, and customer demographics. Customer adoption models can help account for many of these factors.

System operators across the United States have begun taking new approaches to account for the shifting paradigms in their energy systems. PJM recently adjusted load forecasting methodologies to better account for behind-the-meter PV. Their original approach used the observed load to forecast future, e.g., historical trending, without adjusting for the effect of behind-the-meter distributed PV on the observed load. Based on this, PJM accounted for load reductions from distributed PV as new end uses in their load forecasting models. PJM has since revised their approach by removing their estimate of historical distributed PV before forecasting load, and then adds back a forecast of distributed PV to their new net load forecast.

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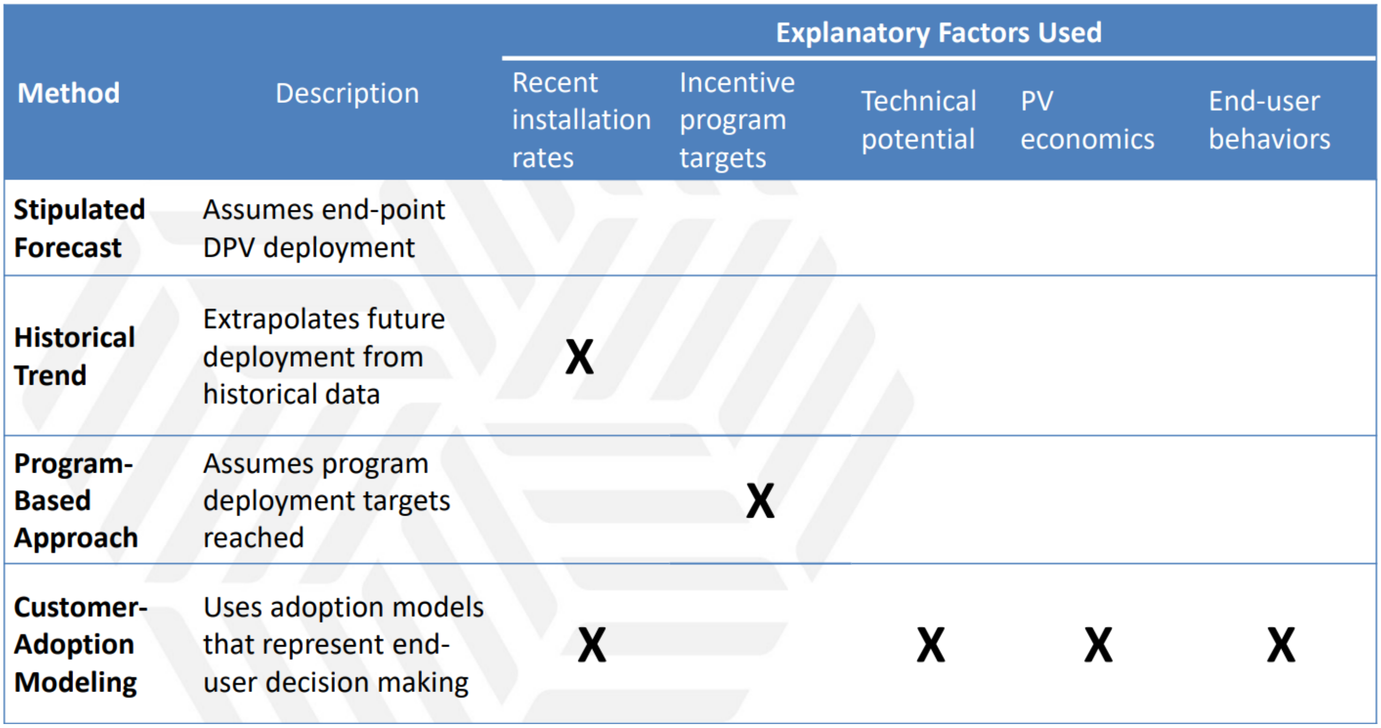
[1],[10] "Forecasting Load on Distribution Systems with DER"; *https://eta-publications.lbl.gov/sites/default/files/6_-_sigrin_forecasting_load_with_ders_1.pdf*

Figure 27 - DER Forecasting Methods as presented in U.S. Dept. of Energy's "Forecasting Load on Distribution Systems with DER" Paper



Method	Description	Explanatory Factors Used				
		Recent installation rates	Incentive program targets	Technical potential	PV economics	End-user behaviors
Stipulated Forecast	Assumes end-point DPV deployment					
Historical Trend	Extrapolates future deployment from historical data	X				
Program-Based Approach	Assumes program deployment targets reached		X			
Customer-Adoption Modeling	Uses adoption models that represent end-user decision making	X		X	X	X

[11] Source: “Forecasting load on distribution systems with distributed energy resources”, U.S. Dept. of Energy

California ISO (CAISO) opts to evaluate distributed PV as a resource option when crafting its load forecast and examining DER in its transmission plans. CAISO’s transmission planning process identifies transmission needs to meet reliability criteria, and then examines feasibility of meeting needs with distributed PV. Then, if CAISO finds it is feasible to meet needs with increased distributed PV, information is passed on to the California Public Utility Commission (CPUC) and utilities determine if programs to encourage additional distributed PV would be cost effective.

ISO New England (ISONE) and New York ISO (NYISO) opt to locate DER within their systems by using load-zone-level distributed PV forecast in their capacity markets and transmission planning efforts, where PJM adjusts the load-zone peak demand by the on-peak contribution of distributed PV for its capacity market and transmission planning.

One key tool now available to the public as of September 2020 is NREL’s opensource of their “dGen DER customer adoption model.” NREL’s goal is to work with planning staff from all seven American ISOs/RTOs to develop joint load / DER forecasts, build out model capacity, and improve modeling methodology, thus creating a more uniform, widely accepted, accurate approach to incorporating DER into load and DER forecasting.

6.3 RAMPING AND FLEXIBILITY TO ACCOMMODATE INCREASING VARIABILITY AND UNCERTAINTY OF DISTRIBUTED PV SOLAR

High penetration of DER may impact bulk power system reliability, requiring ramping and flexibility of bulk generation and controllable load to accommodate increasing variability and uncertainty. There are three main considerations here: 1) Visibility and control of the distribution system; 2) ability to control assets on the bulk grid to effectively balance the system; and 3) improving technology of traditional synchronous bulk generation to effectively balance the system.

Visibility and control of what is happening in the distribution system would help accommodate and offset issues on the larger grid, providing for increased balancing capabilities. More specifically, the ability to coordinate DER generation with demand-side management efforts and electric vehicle charging patterns. This requires sending accurate signals from the utility to DER to have the right behavior for EV charging to offset ramping when needed.

System balancing is typically handled with reg-up and reg-down automatic generation control (AGC), which is a signal that comes from the utility to re-define and re-tune system power to meet load in about 4-6 seconds. Renewable generation, such as wind and solar, have historically not followed reg signals. This is because renewable plants may not be able to follow an AGC signals requesting reg-up services. A generating unit providing reg services typically must have room to move in both directions. Wind and solar can reg-down easily enough through curtailment. However, reg-up is more challenging, as it would require renewables to operate below their full capabilities, which goes against the point of utilizing renewables as a low-cost/no-cost generating source in the first place. Some remedies for this issue include incentivizing reg-up (headroom) and reg-down (curtailment) as it will likely have increased value over time as power systems become more heavily penetrated with renewables and DER. However, these incentives will likely need to come from market design and security-constrained dispatch.

Lastly, traditional synchronous generation in the form of gas technology is being pushed more and more to be flexible, in terms of increased cycling capabilities, faster ramping, more starts, and deeper turndown. These abilities allow asset owners and system operators to maximize the flexibility out of the incumbent fleet. However, it is imperative for system operators to know more about each unit's capabilities and consider these capabilities while dispatching in order to effectively balance the system. Deploying the fastest units within the supply stack naturally provides more value, but when flexibility considerations come into play, system operators will now have to consider if they have enough room up and down to provide what is needed. Said more plainly, they will need to consider reg-up and reg-down capabilities when developing unit commitment and dispatch needs, versus simply dispatching on cost and efficiency metrics. This consideration is key in integrated planning and will be discussed in a later section in more detail.

6.4 POWER SYSTEM PROTECTION AT THE T-D INTERFACE

Distribution systems are designed for quasi-loop operation, meaning loads are normally served from one end of the feeder connected to a distribution substation interfaced with the transmission system, in a radial configuration, at any given time. This is mainly due to the difficulty in protection coordination. With high penetration of DERs, it is possible that power can flow in a substation from the distribution system to the transmission system during some operating conditions. Because of the bi-directional flow created by DER, traditional non-directional feeder overcurrent protection, either at the substation or within the reclosers, should be considered for replacement with directional overcurrent protection during any replacement/upgrade project as older relays approach end of lifecycle or as more DER customers connect and support system upgrades. This is an important issue as this transition may be required in the future and can be challenging. The cost of protection devices is significant at about 20% of the total protection replacement project cost, not to mention there is difficulty in getting permits for the required shutdown during replacement, as well as the inconvenience due to the nature of the overall project. That said, providing redundant protection for the distribution system is a good practice going forward, if not already done, as the distribution system is quickly becoming similar to the transmission system with the high penetration of DERs. Failure or unavailability of a protection system during the maintenance/replacement of any system may cause loss of valuable DER generation.

Penetration of inverter-based resources (IBR) at the transmission or sub-transmission system level can pose challenges for traditional protection systems, specifically for those protections not provided with communication. Protection engineers do not generally use electromagnetic transient (EMT) simulation programs. Short-circuit programs typically used by protection engineers do not accurately represent the transient response of IBRs during the first few cycles after fault inception. Behavior of fast protections, like Zone 1 distance protection, can be affected if not used correctly – with respect to setting and operating time.

The injection of negative sequence current from IBRs, with proper relationship between negative sequence voltage angle and negative sequence current angle, is very useful for the protection system for directional discrimination during unbalanced faults. Use of communication assisted unit protection, such as current differential protection, is very helpful for transmission lines from IBR-dominated plants. Unit protection does not have the challenges of a distance or overcurrent protection if required to trip very quickly while connected to an IBR plant. However, slower distance protection with Zone 2 and Zone 3 tripping times for those transmission lines from IBR plants can supplement current differential protection while also providing remote back-up protection.

The concept of critical clearing time, which is important for the transmission system, may need to be reconsidered and consistently studied as IBRs continue to displace synchronous generation. As synchronous generation retires, there may be opportunities to slow down protection system operation. This is particularly needed where the system is dominated by IBRs, which require some time (cycles) to determine the appropriate response based on observed (measured) terminal conditions. The impact of slowing down protection system operation on critical clearing time of remaining synchronous machines (that may have a faster acceleration/deceleration behavior) should be studied.

Unintended islands can form between an IBR plant or a DER and the related transmission or distribution system, due to the tripping of a tie line either from a fault or due to inadvertent switching. Such an island can subject connected equipment and customers to abnormal voltage and frequency, resulting in possible damage. The protective relay settings within the island may not provide adequate protection, if not provided with adaptive protection, resulting in potential equipment and safety issues. Automatic reclosing is also a concern since reclosing into an island may result in equipment damage. Many IBRs and DERs are equipped with active anti-islanding which may be disabled for ride-through concerns. Use of communication-based island detection systems such as direct transfer trip is helpful to provide unintentional islanding protection. Communication infrastructure used for line protection can be used for the unintentional islanding protection, when available.

6.5 NEED FOR CODES AND STANDARDS TO CONSIDER AN EXPANDED ROLE OF HOSTING CAPACITY ANALYSIS TO IDENTIFY RELIABILITY RISKS

Hosting capacity can be defined as the amount of DER that can be accommodated on the distribution system at a given time and at a given location, e.g. feeder, under existing grid conditions and operations and still maintain its performance, meaning ability to reverse flow and maintain reliability. Hosting capacity is dependent on a variety of things, including:

- The characteristics of the DER along the system, meaning whether advanced or “smart” inverters are being utilized, what the size of the distribution system is, and where the DER is located along the given circuit;
- The location and time-varying behavior of the DER on the circuit, such as distributed storage;
- The existing equipment on a circuit at any given time, which will evolve over time depending on upgrades made by the distribution system owners or DER owners; and
- The distribution planning practices used by the utility – especially how they determine when upgrades or other mitigations are required.[12]

Hosting Capacity Analysis (HCA) can then be defined as performing analysis to develop an estimate of the amount of DER that can be accommodated at a given feeder location without significant upgrades. Understanding the real value of hosting capacity requires a closer look at the intended objectives and the value proposition to stakeholders. If there is an issue on the transmission system and a substantial amount of DER on your distribution feeders, there is potential for all the DERs to trip off at the same time, which therein creates a big event. It is now preferable that DER rides through events to provide voltage support. This is done using “smart” inverters, which can inject reactive power back into the system and provide stability.

There are two main types of HCA. The first is called Snapshot Hosting Capacity, which is the traditional concept of HCA. Snapshot hosting capacity is based on a few snapshots in time using static device settings and behaviors. It does not consider the behavior of loads or DER performance over time or consider grid device behavior. Instead, it looks at extreme scenarios that are unlikely to occur, such as maximum energy output from all DER simultaneously with minimum system load.

The next type of HCA is called Dynamic Hosting Capacity analysis and is based on quasi-static time-series simulations. Dynamic Hosting Capacity does consider the behavior of DER, load, and grid devices over time. Additionally, it accounts for and acknowledges that some short periods of over-voltages and thermal overloads are acceptable over a limited number of time points during the year. Dynamic Hosting Capacity does not look at extreme scenarios like Snapshot Hosting Capacity. Instead, it uses probabilistic screens that consider the uncertainty around the time-series input variables.

In 2017, the state of California instituted Public Utilities Code Section 769, which required electric corporations (e.g. utilities) to file distribution resources plans to identify optimal locations for the deployment of distributed resources. Code Section 769 also required the CPUC to review each distribution resources plan proposal submitted by an electrical corporation and approve, or modify and approve, a distribution resources plan for the corporation. The commission allowed for its own modification of any plan as appropriate to minimize overall system costs and maximize ratepayer benefit from investments in distributed resources.[13] Code Section 769 was part of a larger, ongoing

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[12] NREL “Advanced Hosting Capacity Analysis”; *www.nrel.gov/solar/advanced-hosting-capacity-analysis.hmtl*

[13] *CPUC “Distribution Resources Plan (R.14-08-013)”; www.cpuc.ca.gov/general.aspx?id=5071*

effort in California to perform state-wide integration capacity analysis. During this effort, CA weighed the two aforementioned HCA types: Snapshot HCA (termed as "Streamlined" in a working group paper,) which it deemed more simple and quicker to achieve, versus Dynamic HCA (termed as "iterative" HCA in the working group paper,) which accounted for more variables and complex scenarios but was also more complicated in nature and required much more time to accomplish. At the conclusion of the study, Southern California Edison (SCE) and Pacific Gas & Electric (PG&E) ultimately decided to blend the different HCA types based on complexities (or lack thereof) in their respective systems. San Diego Gas & Electric (SDG&E) concluded that the "iterative" or Dynamic HCA approach was the most appropriate method because it yielded the most accurate results.[14]

6.6 ROLE OF CODES AND STANDARDS TO ACCOUNT FOR ADVANCEMENTS IN DER, AUTOMATION AND PROTECTION TECHNOLOGY

There are two key IEEE grid codes supported by NERC for the integration and performance requirements of DERs and IBRs in North America. The first of standard is IEEE Standard 1547-2018 for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces applicable for distribution systems. The second, which is still in development, is IEEE Standard P2800 for Interconnection and Interoperability of Inverter-Based Resources Interconnecting with Associated Transmission Electric Power Systems and is expected to be published in 2021.

Sub-transmission system interconnection is included in the P2800 standard. The 1547 and P2800 standards are complimentary for any particular jurisdiction, as they don't define distribution and transmission/sub-transmission system boundaries. The two standards mainly focus on performance requirements to be adhered to by any DER and IBR for integration with the power system. There are companion guides that discuss various aspects of IEEE 1547-2018. The focus of the guides are the interpretation of the standard, application, and testing requirements to complement the performance requirements described in the standard 1547-2018. While some the guides have been fully completed, many such guides are at different stages of completion. Most of the companion guides are updated from their original versions focusing on IEEE standard 1547-2003. Significant changes have been made in the 2018 standard from the 2003 standard to address the improvement in technology, better understanding of the of inverter-based resources and grid requirements based on years of practical implementation of IEEE 1547-2003 and associated guides – a total of seven such companion documents comprising of one standard, one recommended practice, and four guides.

Protection and automation issues are addressed in more detail in the IEEE 1547-2018 standard and the associated application guide P1547.2, expected to be published in 2021.

At the state-level, one key development is California Public Utility Commission's 2017 tariff entitled "California Rule 21." Broadly, the rule "describes the interconnection, operating and metering requirements for generation facilities to be connected to a utility's distribution system" and, "provides customers wishing to install generating or storage facilities on their premises with access to the electric grid while protecting the safety and reliability of the distribution and transmission systems."[15] The implications of this rule on the DER space, however, is that it effectively requires the use of advanced, or "smart" inverters in new solar and other distributed electricity generating projects.

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[14] Utility Dive "How California's utilities are mapping their grids for distributed resources"; *www.utilitydive.com/news/how-californias-utilities-are-mapping-their-grids-for-distributed-resource/436899/*

[15] "Rule 21 Interconnection (ca.gov)"; *www.cpuc.ca.gov/rule21*

California has a Renewable Portfolio Standard of 100% renewables by 2045 (and an interim goal of 60% by 2030). This means that DER is expanding rapidly in the state, which can create potential grid disruptions if not adequately planned for. Smart inverters can help ensure that solar and other DER do not make grid disturbances worse. Prior to the use of these smart inverters, PV systems were required to immediately disconnect when grid disruptions occurred, which could inevitably cause a large amount of DER capacity to disconnect and further destabilize the grid. Smart inverter functions allow DER systems to remain connected to the grid under a wider range of voltage and frequency levels, which in turn allows for a more flexible grid.

6.7 NEED FOR CODES AND STANDARDS TO ACCOUNT FOR INTEGRATED T&D PLANNING AND OPERATIONAL PRACTICES

For integrated T&D planning, the primary push at the moment from these industry groups I think is to model DERs appropriately in transmission studies. Primarily there is a push to use composite load model instead of ZIP models, because composite load model has several components that more accurately capture load behavior: 3-ph motor, 1-ph motor, static load, electronic load, DERs. Especially areas where FIDVR events are known issues due to 1-ph motor stalling, heavy emphasis is put on modeling loads using cmpldw and parameterizing them using tools available from entities like PNNL, NERC, and EPRI.

In addition to using composite load modeling, there is an expanded discussion of integrated planning practices in Section 10.

6.8 CONTEXTUAL DISCUSSION OF THE POLICY/MARKET DRIVERS IMPACTING DER DEPLOYMENT, GROWTH, AND PROLIFERATION

As the global trend towards decarbonization grows, there are many things impacting the speed and intensity in which DER is expanding, how it is deployed, and its overall effects on the larger grid, specifically in the form of traditional synchronous generation displacement. General attitudes around decarbonization have shifted dramatically:

- The environment and general sustainability are now mainstream concerns
- The technology required to tackle these concerns has been developed and refined
- That technology has reached the point where it can be economical, meaning it can compete with traditional, synchronous generation on cost and performance
- Financial incentives continue to be available (for now) in the form of tax credits, rebates, feed-in tariffs, net metering, and specialty electricity rates
- There has been additional innovation in business models to allow customers without the operational or financial means to obtain and make use of renewable and/or distributed energy resources
- Lastly, as is often the driving factor to any big change, is domestic and state-level policy, setting decarbonization targets and requirements via Renewable Portfolio Standards and the like.

A SELECTION OF U.S. DOMESTIC POLICIES CAUSING DECARBONIZATION FOCUS

The following FERC policies are influential to allowing coordination and interoperability of DER to participate and support bulk grid needs.

FERC policies

- **FERC Order 755:** pay for performance regulation, payment for providing frequency regulation based on capacity offered to provide regulation, mileage payment based on the accuracy of the response,
- **FERC Order 841:** passed in 2018 – "directed regional grid operators to remove barriers to the participation of electric storage in wholesale markets. By directing the regional grid operators to establish rules that open capacity, energy, and ancillary services markets to energy storage, the Order affirms that storage resources must be compensated for all of the services provided and moves toward leveling the playing field for storage with other energy resources. Order 841 creates a clear legal framework for storage resources to operate in all wholesale electric markets and expands the universe of solutions that can compete to meet electric system needs."[16]
- **FERC 2222:** allowing DER to aggregate to participate in wholesale power markets dramatic affect in growth/proliferation of der, as well as displacement of synchronous generation

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[16] "Overview of FERC Order 841 - Energy Storage Association"; *energystorage.org/policy-statement/overview-of-ferc-order-841/*

7 APPLICABILITY OF EXISTING AND IN-DRAFT STANDARDS

This section outlines some of the relevant industry standards, working group and other leadership activities related to grid resiliency, accommodating higher penetration of IBRs and the energy transition.

7.1 IEC TC8: SC8A / SC8B / SC8C

The International Electrotechnical Commission (IEC) utilizes the TC8 technical committee to develop and review international standards, technical specifications and technical reports regarding **systems aspects for electrical energy supply**. TC8's mandate is to prepare and coordinate the development of international standards and other deliverables with emphasis on overall system aspects of electricity supply systems and acceptable balance between cost and quality for the users of electrical energy. This encompasses transmission and distribution networks and generators and loads with their network interfaces. The TC8 committee's scope includes standardization in the field of:

1) Terminology for the electricity supply sector;

2) Characteristics of electricity supplied by public networks;

3) Network management from a system perspective;

4) Connection of network users (generators and loads) and grid integration; and

5) Design and management of de-centralized electricity supply systems e.g. microgrids systems for rural electrification.[17]

TC8 has three subcommittees focusing on different tasks: SC8A, SC8B, and SC8C. Each subcommittee has its own overarching topic and various focus issues that are covered in depth. Figure 28 outlines the overall structure and scope of TC8 and its subcommittees.

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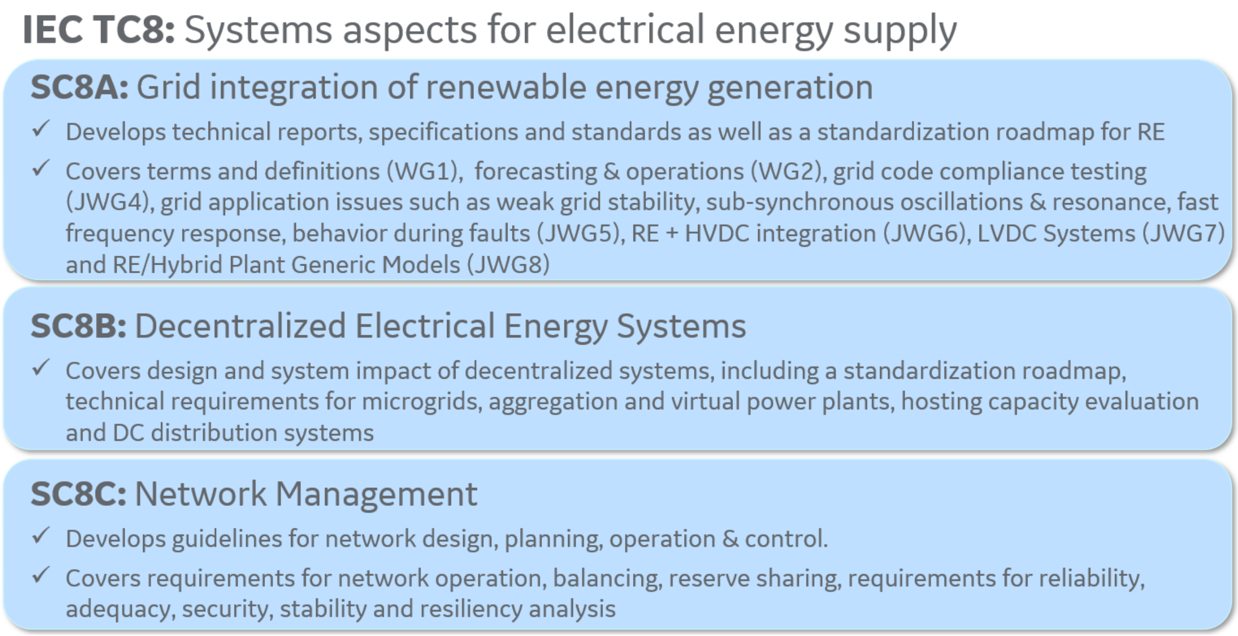
[17] "IEC - TC 8 Dashboard> Scope"; *https://www.iec.ch/dyn/www/f?p=103:7:0::::FSP_ORG_ID,FSP_LANG_ID:1240,25*



IEC TC8: Systems aspects for electrical energy supply

SC8A: Grid integration of renewable energy generation

- ✓ Develops technical reports, specifications and standards as well as a standardization roadmap for RE
- ✓ Covers terms and definitions (WG1), forecasting & operations (WG2), grid code compliance testing (JWG4), grid application issues such as weak grid stability, sub-synchronous oscillations & resonance, fast frequency response, behavior during faults (JWG5), RE + HVDC integration (JWG6), LVDC Systems (JWG7) and RE/Hybrid Plant Generic Models (JWG8)

SC8B: Decentralized Electrical Energy Systems

- ✓ Covers design and system impact of decentralized systems, including a standardization roadmap, technical requirements for microgrids, aggregation and virtual power plants, hosting capacity evaluation and DC distribution systems

SC8C: Network Management

- ✓ Develops guidelines for network design, planning, operation & control.
- ✓ Covers requirements for network operation, balancing, reserve sharing, requirements for reliability, adequacy, security, stability and resiliency analysis

Figure 28: IEC TC8 subcommittees related to grid integration of RE and network management

SC8A: Grid Integration of Renewable Energy Resources

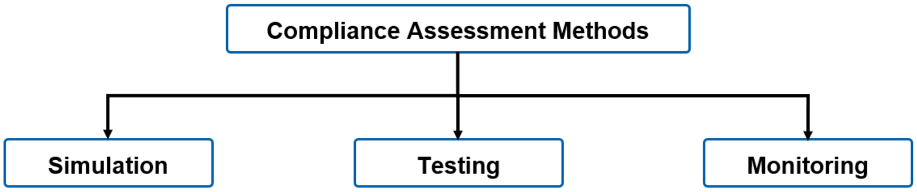
The SC8A subcommittee focuses on grid integration of renewable energy. Specifically, it works to develop technical reports, specifications, and standards, as well as a standardization roadmap for renewable energy. SC8A covers Forecasting & Operations (WG2), Grid Code Compliance Testing (JWG4) and Grid Application Issues such as weak grid stability, sub-synchronous oscillations & resonance, fast frequency response, behavior during faults (JWG5).

The "WG2" Forecasting and Operations focus covers the following in scope:

- Classify forecasting based on temporal & spatial scales, input data, forecasting model and form
- Describes typical processes for NWP, statistical and wind/solar forecasting, with detailed description of models used worldwide
- Ensemble & probabilistic forecasting covered in some details
- Identify strengths and limits of different forecasting approaches
- Develop metrics and evaluation methods
- Develop improvements to models and methods

Some recommendations to come out of this focus consist of developing standards for data instrumentation and collection for renewable energy power forecasting, developing NWP model system for synoptic processes, developing methods to adequately assess the value and performance of forecasts specific to the applications, and lastly to apply new technologies such as artificial intelligence in power forecasting.

The "JWG4" Grid Code Compliance focuses specifically on recommending technical methods of grid code compliance assessment for grid connection of wind and PV power. The studies center on electrical behavior such as operational boundaries, control performance characteristics, fault ride through, and power quality, and utilize compliance assessment methods of simulation, testing, and monitoring as depicted below.



The "JWG5" Grid Application Issues technical focus is on system issues for integration of wind and PV generation into the bulk electrical grid, and specifically centers on the subcommittee writing technical reports that address standardization of the following:

- Weak AC system connection, inverter control stability and short circuit ratio (SCR) as a metric to represent the voltage stiffness of a grid, which covers performance, modeling, testing, Composite Short Circuit Ratio (CSCR) screening
- Special Application issues and analysis: Super and Sub-Synchronous Control Interaction, power system damping, which covers SSCI phenomenon, modeling & analytical techniques, mitigation & damping
- Fast Frequency Response and Inertial Support Capability of IBRs, which covers performance, procurement and coordination of SIR, FFR and PFR
- Performance during faults (current injection during balanced and unbalanced disturbances)
- Covers fault current and current injection behaviour of IBRs during disturbances, ride through and impact on protection

The "JWG6" Interconnections of HVDC and RE Systems group is focused on defining technical reports, specifications and standards on interconnecting wind and solar rich areas via HVDC lines.

The "JWG7" LVDC systems is focused on a newer concept of creating a compete DC distribution network.

The proposed "JWG8" is focused on developing generic RMS and EMT models for wind, solar and hybrid power plants. This is a new joint working group that is still establishing its charter and scope relative to other areas and working groups in IEC.

SC8B: Decentralized Energy

The SC8B subcommittee focuses on decentralized energy electrical systems, and specifically covers design and system impact of decentralized systems, including a standardization roadmap, technical requirements for microgrids, aggregation and virtual power plants, hosting capacity evaluation, and DC distribution systems. There are three (3) technical focuses of note in SC8B. The first is JWG1, which examines the general planning, design, operation, and control of microgrids. JWG1 has provided two technical scope documents, "62898-1: Microgrid part 1: Guidelines for project planning and specification" and "62898-2: Microgrid part 2: Guidelines for operation." The second technical focus is AHG2, which provides a roadmap of decentralized electrical energy systems. The final technical scope is WG4, which examines virtual power plants. WG4 has two standards developed, "IEC 63189-1: Virtual Power Plants – Architecture and Functional Requirements" and "IEC 63189-2: Virtual Power Plants 2 – Use Cases."

SC8C: Network Management

Lastly, the SC8C subcommittee focuses on network management, and specifically develops guidelines for network design, planning, and operation and control. SC8C also covers requirements for network operation, balancing, reserve sharing, requirements for reliability, adequacy, security, stability, and resiliency analysis. The scope of SC8C is to standardize the field of network management in interconnected electric power systems with different time horizons including design, planning, market integration, operation and control.

- The subcommittee also focuses on developing guidelines, technical reports, specifications and standards on the following:
- Terms and definitions found in the area network management
- Guidelines for network design, planning, operation, control, and market integration
- Contingency criteria, classification, countermeasures, and controller response, as a basis of technical requirements for reliability, adequacy, security, stability, and resilience analysis
- Functional and technical requirements for network operation management systems, stability control systems
- Technical profiling of reserve products from Demand Side Response for effective market integration
- Technical requirements of wide-area operation, such as balancing reserve sharing, emergency power wheeling

7.2 IEEE P2800

P2800[8 above] is the IEEE Standard focusing on “Interconnection and Interoperability of Inverter-Based Resources (IBR) Interconnecting with Associated Transmission Electric Power Systems.” The Standard is intended to establish the required interconnection capability and performance criteria for inverter-based resources interconnected with transmission and sub-transmission systems. While P2800 is under development at this point, it is likely the final Standard will specify performance and function capabilities of IBR, specify function default settings of IBR, specify functional ranges of allowable settings, specify modeling data and measurement data for performance monitoring and validation, and specify required test and verifications (but not their detailed procedures.)

P2800 addresses the following in detail:

- Reactive power capability at nominal voltage
- Reactive power capability vs RPA voltage
- Transient overvoltage ride-through
- Primary Frequency Response (PFR)
- Fast Frequency Response (FFR)

P2800 addresses reactive power capability at nominal voltage for both injecting and absorbing reactive power (generating/motoring/charging modes). It specifies reactive power to be +/-0.95pf at RPA (POI) voltage in all modes of operation. It also addresses reactive capability at off-nominal POM voltages, where the corners of the capability curve are cut to avoid requiring delivery of reactive power during high voltage or absorption at low voltage.

P2800 addressing reactive power capability vs RPA voltage.

The P2800 Standard addresses transient overvoltage ride-through by stating that all IBR plant shall be capable to ride-through the higher of each phase-phase or phase-ground instantaneous voltages up to 180% for 1.6ms. During the transient period up to 15ms, momentary cessation is allowed above 120% V_{POM}. ***This requirement is a best practice and should be considered for adoption in Canada.***

The Standard addresses Primary Frequency Response (PFR) capability of an IBR by stating that the PFR capability of any given IBR shall meet the performance requirement at RPA, PFR response in the continuous and mandatory operation region for frequency, and continuous operation region for voltage.

Lastly, the Standard addresses fast frequency response (FFR) by stating that all IBR shall have FFR capability for under-frequency conditions; FFR capability may be deployed for the purposes of ancillary service offering; and the FFR response time capability shall be adjustable from 1 second or below including the reaction time for triggering FFR.

7.3 IEEE 1547

IEEE 1547 is a foundational document that provides the technical specifications for, and testing of, the interconnection and interoperability between utility electric power systems and distributed energy resources, or DERs. With the rapid expansion and anticipated future growth of DERs in the United States, the set of standards regarding their development and usage along the macrogrid became increasingly critical for overall system reliability and safety, and thus Standard 1547 was developed. Standard 1547 is the only American National Standard that addresses systems-level DER interconnected with the distribution grid. Because of this, it had and continues to have a significant effect on how the energy industry does business. It has helped to modernize the electric power systems infrastructure by providing a base for integrating renewable energy technologies and other distribution generation and storage technology resources into the larger power grid. [18]

The Standard has eight (8) related Standards based off of the original Standard. These include:

- IEEE 1547.1: Provides additional detail on interconnection testing;
- IEEE 1547.2: Provides a more technical background on the 1547 Standard;
- IEEE P1547.3: Provides a detailed background on cyber security requirements (Draft form at this time);
- IEEE 1547.4: Provides a guide for designing, operating, and integrating of conforming systems;
- IEEE 1547.6: Provides a description of practices for secondary network connections;
- IEEE 1547.7: Provides distribution impact studies for distributed resource interconnections;
- IEEE 1547.9: Provides details surrounding energy storage guidelines;
- IEEE 1547.2018: The "Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces" - an update to the original Standard (1547.2003);

IEEE 1547.2018 provides for the technical specifications for, and testing of, the interconnection and interoperability between utility electric power systems (EPSs) and distributed energy resources (DERs).

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[18] IEEE 1547 and 2030 Standards for Distributed Energy Resources Interconnection and Interoperability with the Electricity Grid (nrel.gov)

It provides standards relevant to all aspects of DER integration, ranging from performance and operation to testing, safety, and maintenance. The requirements apply to all forms of DER interconnection, and include synchronous machines, induction machines, and/or power inverters/converters.[19]

7.4 EU Massive Integration of Power Electronic Devices (MIGRATE) and Horizon 2020

MIGRATE, which stands for "the Massive InteGRATion of power Electronic devices," was a project funded by the European Commission's 2020 Horizon program that combined expertise from 12 European transmission providers and 13 industry partners to focus on research and innovation for enabling the clean energy transition. The project sought to provide solutions to some of the most pressing technological challenges that regional transmission operators face as they continue to push to reach the EU Commission's renewable targets of 32% by 2030. The MIGRATE project lasted for four years and was completed in December of 2019.

The MIGRATE project sought to understand both how much renewable energy today's electric network can cope with, and ultimately what tomorrow's electric network must look like in order to integrate more – or even exclusively going forward – renewable energy. These core topics yielded the following critical questions:

- With more renewable energy coming online, the inertia in the power system will decrease consequently leading to a 'faster' system response. Will the power electronic converter controls — initially designed for 'slow' conventional power systems — be able to cope with this?
- How can the various protection schemes — i.e., the detection and isolation of faults — be adapted to the new power system characteristics, e.g., very low fault currents?
- What is the impact of massively integrated power electronic units on power quality (voltage, frequency, waveform), and how can this impact be mitigated?

MIGRATE explored these different questions by investigating the different dimensions of power system stability (e.g., how it can be measured, monitored and forecasted,) exploring how a power system with 100% power electronics could be operated, and what would be a transitional pathway to that point, assessing the maximum share of power electronics in a power system before mitigation measures are required to maintain system stability and how it should be mitigated, and by developing and testing new tools to ensure power system protection, automated control and power quality in power systems with high PE penetration.

In the end, the MIGRATE project provided the following list of recommendations based off of the work of its participants[20]:

1) To encourage Transmission System Operators to make use of their synchro-phasor data. There is a critical need to observe the dynamic characteristics as inertia and system strength issues impact stability among other stability Key Performance Indicators.

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[19] IEEE 1547-2018 - IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces

[20] H2020 Migrate (h2020-migrate.eu)

2) To consider inertia as clusters connected by network corridors, and not as a single system-wide inertia. Angle stability is also related to regional inertia, and islanding can occur in low inertia regions even in larger high-inertia systems or interconnections.

3) To encourage Transmission System Operators to explore possibilities of Wide-Area-Controls within their grids. They are a very valuable and economical approach for locational fast frequency control, enabling network stability improvements together with frequency management.

4) To differentiate system strength (or "stiffness") from short circuit level. The historic assumption that they were approximately the same is no longer valid.

5) To be aware of system strength issues which can lead to higher frequency oscillation phenomena, typical 4–12Hz voltage control oscillations. Fast oscillatory instability detection is available that can be used to detect, alarm and potentially mitigate the rapid onset of these oscillations.

6) To use a probabilistic approach to harmonics mitigation since taking into account future scenarios enables more future-proof solutions.

7) To use optimization-based approaches to design the most cost-effective mitigation strategies for harmonics.

8) To use new wind turbines control algorithm, which significantly reduces the frequency variations, is easy to implement in (existing) wind turbines and only minimally reduces total energy output.

9) To create new or modify the existing balancing service, focusing on frequency variations mitigation using wind turbines in order to significantly reduce the primary and secondary regulation needs.

10) To consider requiring grid forming control functionality in the specification of future power electronic projects. While the exact required percentage of GFM IBPSs depends on the local characteristics of the system being evaluated, research has shown that a general rule of thumb of 10% – 30% of the total IBR penetration is adequate.

11) To prepare for more detailed modeling of power systems and power electronic units in order to maintain Transmission System Operator ability to analyze future power system stability under high power electronic penetration, in particular in terms of SSCI and PQ.

12) To continue the in-depth analysis how the application of Artificial Intelligence techniques in grid planning and operation can facilitate the massive power electronic integration.

13) To further explore the possibilities how power electronic penetration can be monitored using real-time online measurements of typically available power system signals.

14) To open the grid code for grid forming requirement from inverters. Main guidelines are presently within MIGRATE[21]. Grid forming technology is the only enabler for a 100% power electronic grid, and it already showed positive impact on grid with synchronous machines.

15) To review protection philosophy and criteria in order to ensure a secure transition towards a power system with high penetration of power electronics.

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[21] https://www.h2020-migrate.eu/_Resources/Persistent/1bb0f89024e41a85bf94f1ec7ee6f8d7c34bc29a/D3.6%20-%20Requirement%20guidelines%20for%20operating%20a%20grid%20with%20100%20power%20electronic%20devices.pdf

16) To define clear requirements for the behavior of power electronics during balanced and unbalanced faults and, ideally, these requirements should be harmonized at European level.

17) To implement new protection technologies such as adapted distance protection algorithms, time-domain protection functions and WAMPAC systems can facilitate the transition, however careful assessment of these technologies and their applicability to specific power systems must be made, as their behavior will be greatly affected by the controls of power electronics.

18) to review the tools commonly employed by protection engineers in their studies, in order to adapt them to this new scenario in which power electronics expertise must be included.

7.5 Energy Systems Integration Group and Global Power System Transformation Consortium

Energy Systems Integration Group (ESIG)[22]

The Energy Systems Integration Group (ESIG) takes a total system view of the energy systems we use today, focusing on the combined strength of electricity, heat and fuel systems. Tapping into the combined strength of energy systems maximizes the value of every unit of energy being used for power, heat, water, commercial/industrial, residential and transportation purposes. Through collaboration and coordination, ESIG addresses the technical challenges associated with integrating multiple energy systems to enable clean, reliable, and affordable energy systems worldwide. Without the energy systems integration perspective, the full potential of all available energy sources will never be reached.

Energy Systems Integration (ESI) is the process of coordinating the planning and operation of energy systems across multiple pathways and/or geographical scales to deliver reliable, cost effective energy services with minimal impact on the environment.

ESIG has five working groups:

- Reliability WG
- Distributed Energy WG
- System Planning WG
- System Operation and Market Design WG
- Research and Education WG

All working groups have a primary focus on the impact of higher shares of IBR in their subject areas. The reliability working group has one task force, called “High Shares of IBR TF”, that is focused on generating a whitepaper and other work products about design, deployment, modeling and stability mitigation of grid forming controls. This whitepaper, entitled “**The Role of Grid Forming Technology to Enable Energy Systems Integration**” is focusing on the following:

- Definition of grid forming
- Grid Forming control Methods
- International Project References and Grid Forming Applications
- Characterization of Grid Forming Resources to Support Grid Needs

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[22] Energy Systems Integration Group www.esig.energy

- Summary and Lessons Learned with Interconnection Requirements and Services Incentivizing grid forming capabilities
- Outlook for grid forming resources, including needs for standardization, modeling and validation, system protection needs, implementation challenges and mix of grid forming to grid following resources.

The whitepaper is due to be published later in 2021.

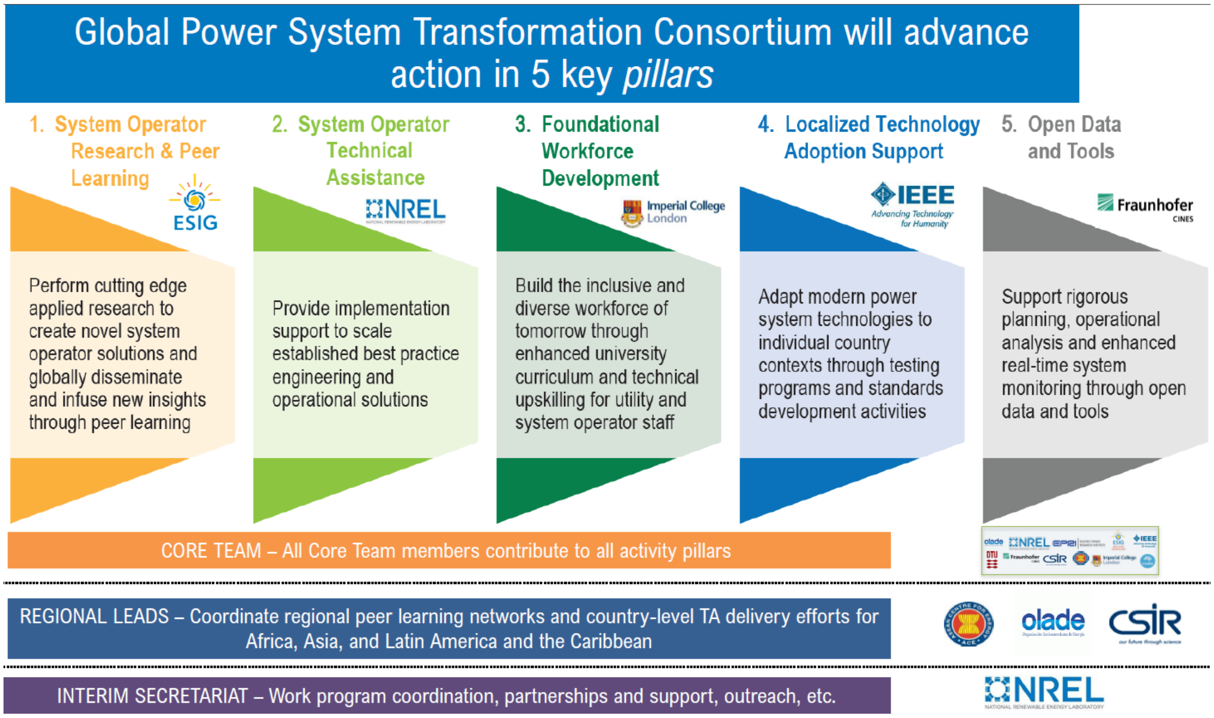
Global Power System Transformation Consortium (GPST)

The Global Power System Transformation Consortium (GPST) was founded from a special ESIG workshop focused on defining research pathways to 100% renewable Energy in May 2019. This consortium's inaugural Plenary was in October 2019. The chief executive officers of ***National Grid Electricity System Operator UK, California Independent System Operator (CAISO), Electric Reliability Council of Texas (ERCOT), Australia Energy Market Operator (AEMO), Ireland's System Operator (EirGrid), and Denmark's System Operator (Energinet)*** are champions in developing the consortium mission and activities. These system operators are leading a Research Agenda Group to identify common, cutting-edge research questions that can inform large- scale national research and development investments. Relevant results and lessons from this process will be broadly shared for learning across all countries. The Consortium is also partnering with around 10 emerging economy and developing country system operators from Africa, Asia, Latin America and Eastern Europe who will also guide the G-PST vision and collaborate with the Consortium to advance power system transformation with a focus on technical collaboration, peer learning and exchange, and workforce development to support local PST priorities.

A core team, including the Energy Systems Integration Group (ESIG), Imperial College London, Council of Scientific and Industrial Research (CSIR), Fraunhofer Cluster of Excellence for Integrated Energy Systems, National Renewable Energy Laboratory, Latin American Energy Organization (OLADE), IEEE, Electric Power Research Institute (EPRI), Commonwealth Scientific and Industrial Research Organization (CSIRO), the Danish Technical University (DTU), and ASEAN Center for Energy, is actively developing the consortium and will be engaged in implementation of technical work as well as coordinating specific pillars.

The core mission of the GPST is to support the Founding System Operators and Developing System Operators through defining core research and deployment of new technologies, methods and standards in the face of the energy transition. The ESIG whitepaper on Grid Forming Technology will set the foundation for research and deployment of GFM technology. This research will be used to support future grid needs for the GPST stakeholders and enable grid forming capabilities in resources as well as new tools and planning methods. The overall structure of GPST, with 5 pillars, is seen in Figure 29.

The outcome of the research from these pillars will directly influence grid code and technical regulatory development and this will have a direct benefit to all system operators and policy makers across Canada.



Global Power System Transformation Consortium will advance action in 5 key *pillars*

1. **System Operator Research & Peer Learning**
   Perform cutting edge applied research to create novel system operator solutions and globally disseminate and infuse new insights through peer learning
2. **System Operator Technical Assistance**
   Provide implementation support to scale established best practice engineering and operational solutions
3. **Foundational Workforce Development**
   Build the inclusive and diverse workforce of tomorrow through enhanced university curriculum and technical upskilling for utility and system operator staff
4. **Localized Technology Adoption Support**
   Adapt modern power system technologies to individual country contexts through testing programs and standards development activities
5. **Open Data and Tools**
   Support rigorous planning, operational analysis and enhanced real-time system monitoring through open data and tools

CORE TEAM – All Core Team members contribute to all activity pillars

REGIONAL LEADS – Coordinate regional peer learning networks and country-level TA delivery efforts for Africa, Asia, and Latin America and the Caribbean

INTERIM SECRETARIAT – Work program coordination, partnerships and support, outreach, etc.

Figure 29: Organizational Structure of Global Power System Transformation Consortium

8 REVIEW AND RECOMMENDATIONS FOR SIMULATION MODEL REQUIREMENTS

8.1 MODELING RECOMMENDATIONS

Given the increasing penetration of inverter-based resources alongside the retirement of legacy thermal generation, the demands on system modeling proficiency are only expected to increase. The most prominent case for this trend has occurred with stability analysis. Dynamic simulation tools are generally divided between positive-sequence stability tools, where integration time steps are typically measured in milliseconds, versus electromagnetic transient (EMT) tools, with time steps in microseconds. However, grid operators are now using validated EMT tools for evaluating longer time frames, to the point where the distinction between short-term and long-term stability has become blurred. It thus becomes essential to carefully assess the technical considerations involved with power system modeling. Some general recommendations can be made as follows:

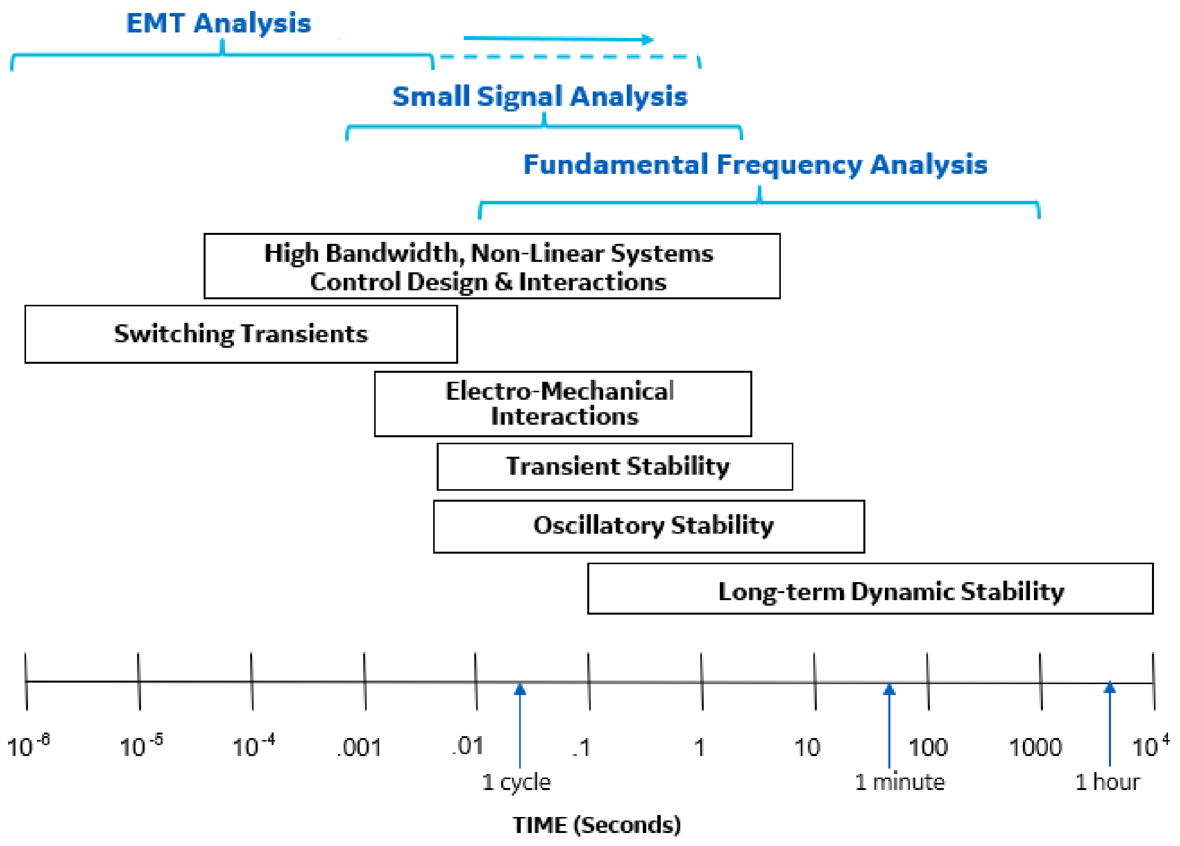


Figure 30: Timescales of system phenomena and analysis

8.2 DYNAMIC MODELING

In addition to the choice between positive-sequence and/or EMT tools, operators also have an option within positive-sequence software programs of whether to utilize user-defined models or instead rely on so-called generic models. A general comparison of the two is shown in Table 23.

Table 23: Comparison of positive sequence stability model types

USER-DEFINED	GENERIC
Vendor-specific.	Standard framework developed by industry org.
More accurate representation than generic.	Functionality is limited by structure.
Can include functions not explicitly modeled in generics.	Long lead time on updates.
Requires additional files (e.g., DLL) to run with software.	Typically part of standard software library.

For practical reasons related to model deployment, system operators only accept generic models for proposed generation. Generic models are more easily integrated into planning cases and no not require non-disclosure agreements. There are certain situations, however, where the generic models will not fully capture the equipment capability or system risk (such as the case with complex tightly integrated multi-plant interconnections, weaker grid connections or plants with fast frequency response). Given the tradeoffs involved with model application, it is recommended that user-defined models be allowed to investigate complex interconnections where generic models may be limited.

EMT MODELS

Some grid operators require EMT models be supplied with all proposed generation. Such requirements are not unusual for isolated grids, with HydroQuebec and ERCOT the most prominent examples. For larger area grids, it is recommended that a general criterion should be formulated when considering the usage of EMT models:

- APPLICATION FOCUS: The application of the model should be clearly identified. What is the model being used to assess? Common application issues are sub-synchronous control interactions (SSCI), inverter control interactions, and weak grid connections.
- WEAK GRID ASSESSMENTS: A process for assessing weak grid connections should be articulated. The following outline can be a useful framework:
    - PHASE 1 (SCREENING) – Formal evaluation of short-circuit ratio (SCR) for normal and worst-case contingency scenarios, with boundary buses clearly defined. The screening study is to be performed using the most up-to-date positive-sequence planning models. Note that different SCR metrics can be considered, depending on the nature of the reliability risk.
    - PHASE 2 (CONTINGENCY ANALYSIS) – The system EMT model is developed based on the screening phase, with relevant contingencies identified. Different plant level output levels should also be defined. Simulations are then conducted to demonstrate the nature of the risks.
    - PHASE 3 (MITIGATION) – Potential mitigation strategies are evaluated, including control modifications and/or system reinforcements along with cost implications.
    - PHASE 4 (IMPLEMENTATION) – A plan for implementing the chosen mitigation strategies is developed, with testing and commissioning procedures included as appropriate.

- IP CONSIDERATIONS: As usage of EMT models typically involve intellectual property (IP) concerns, it is recommended that a standard arrangement for dealing with requisite non-disclosure agreements (NDAs) be formulated.
- THIRD PARTY CONSIDERATIONS: If the system issue involves multiple equipment vendors, it is recommended that a third party engineering firm be considered to alleviate conflicts-of-interest regarding study recommendations.

8.3 HARMONIC MODELING

- Norton equivalent representations are recommended for modeling inverter-based resources.
- Ensure that all analysis accounts for grid background harmonics. Related: proper interpretation of measurements is important for validation!
- Given that inverter-based resources are distributed across a collector system, it should be understood that assuming harmonic injections will all be in phase is overly conservative. A methodology such as IEC 61400-21 Ed 2.0, Section 8.3 should be considered as part of any analysis.

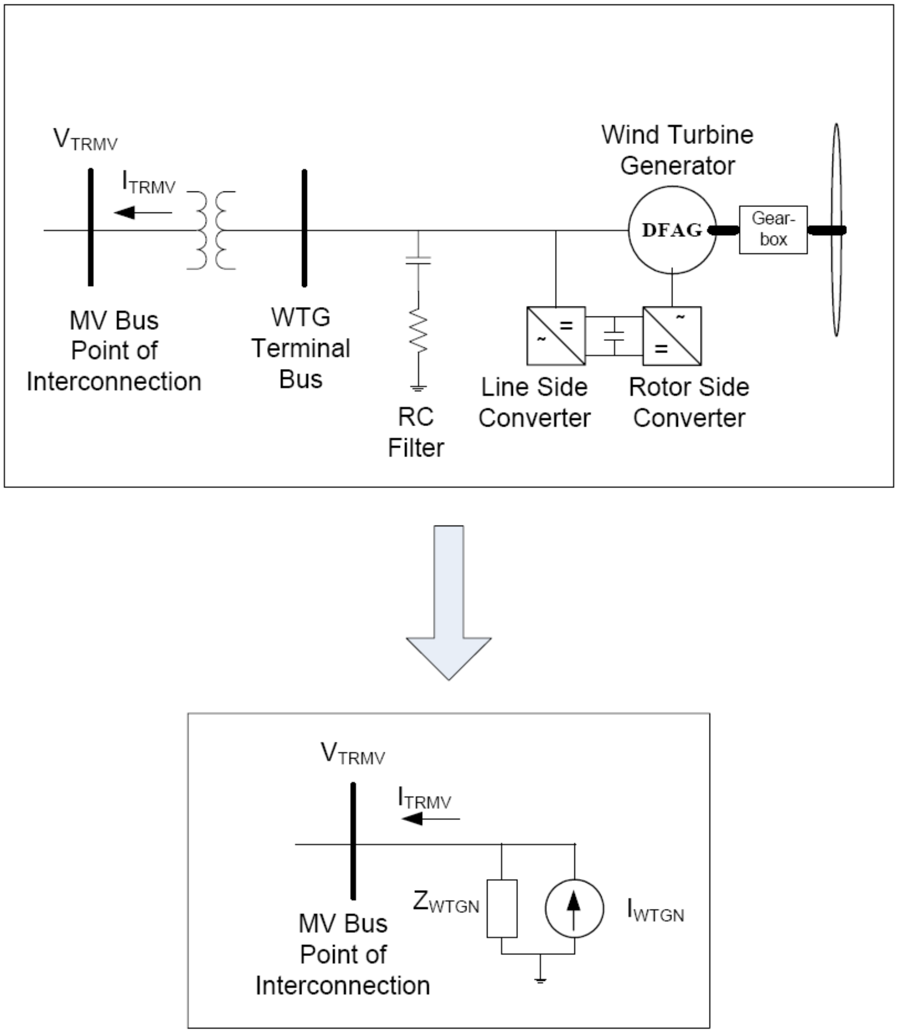


Figure 31: Norton equivalent harmonic current injection model

8.4 SHORT-CIRCUIT MODELING

Modeling fault behavior of inverter-based resources is not straightforward, given that the dynamics are primarily a function of the controls rather than the generator characteristics. Given that controls can vary substantially between designs, this means that the behavior is not adequately represented by the standard model assuming a fixed voltage source behind a reactance which is utilized by short-circuit analysis programs. The IEEE Power and Energy Society issued a report entitled *Fault Current Contributions from Wind Plants*[23] which contains useful directives for assessing fault behavior and is thus being used by software vendors for model development, most prominently by representing inverter-based resources as current-limited generators. Equipment manufacturers can utilize this framework by evaluating ranges of fault current values versus time frames and residual voltages during faults, which can then be used as study parameters. It is recommended that system operators adopt this new framework going forward and keep up-to-date with software packages that accommodate it.

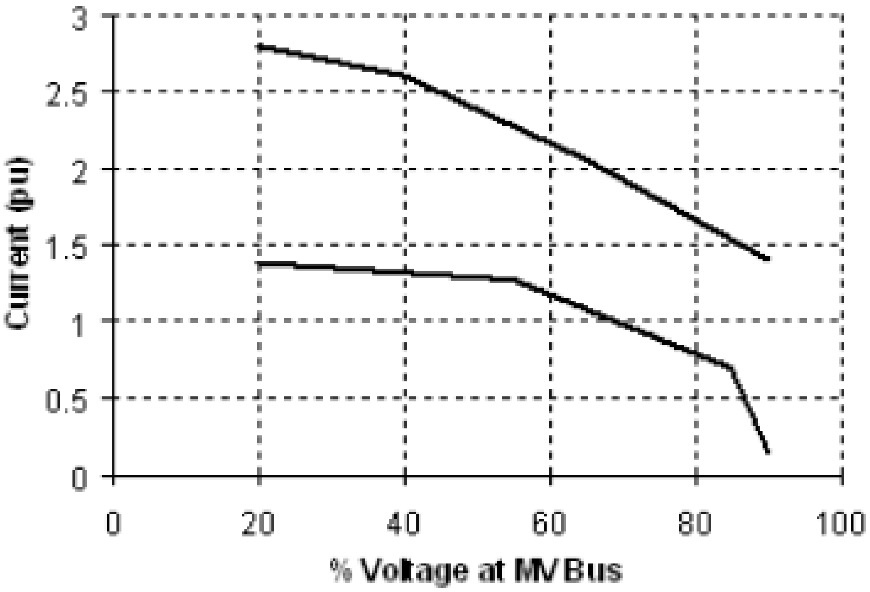


Figure 32: Maximum and minimum symmetrical short-circuit current magnitudes as a function of residual voltage

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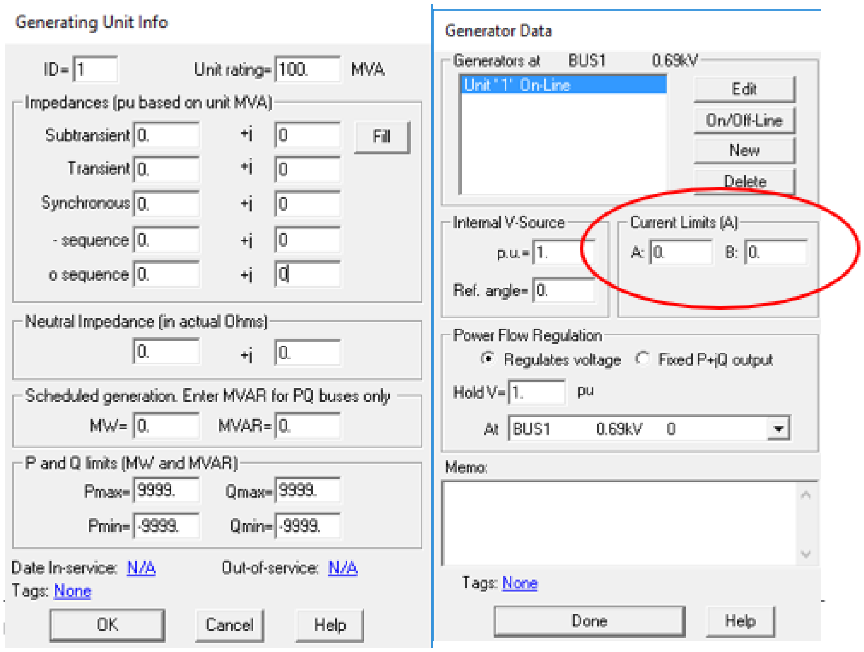
[23] Walling, R., Gursoy, E., English, B., “Current Contributions from Type 3 and Type 4 Wind Turbine Generators During Faults”, IEEE PES 2011



Generating Unit Info

ID= 1 Unit rating= 100. MVA

Impedances (pu based on unit MVA)

Subtransient 0. +j 0

Transient 0. +j 0

Synchronous 0. +j 0

- sequence 0. +j 0

o sequence 0. +j 0

Neutral Impedance (in actual Ohms)

0. +j 0.

Scheduled generation. Enter MVAR for PQ buses only

MW= 0. MVAR= 0.

P and Q limits (MW and MVAR)

Pmax= 9999. Qmax= 9999.

Pmin= -9999. Qmin= -9999.

Date In-service: N/A Out-of-service: N/A

Tags: None

Generator Data

Generators at BUS1 0.69kV

Unit '1' On-Line

Internal V-Source

p.u.= 1.

Ref. angle= 0.

Current Limits (A)

A: 0. B: 0.

Power Flow Regulation

● Regulates voltage ○ Fixed P+jQ output

Hold V= 1. pu

At BUS1 0.69kV 0

Memo:

Tags: None

Figure 33: Aspen Oneliner short circuit modeling inputs

9 RECOMMENDATIONS ON THE ROLE OF ELECTRICITY MARKETS AND REMOVING BARRIERS TO PARTICIPATION OF INVERTER-BASED DISTRIBUTED ENERGY RESOURCES

9.1 Task Scope

Looking beyond real time and day-ahead energy markets, consider additional market products and mechanisms for capacity, ancillary services, and imbalance for ways to incentivize and equitably pay for the performance and functionality that is needed to diversify the energy mix and unlock the value of distributed and large-scale energy storage.

This task will provide an overview of the role market and rule-based energy trading mechanisms play in supporting grid stability and reliability needs and make recommendations for various market products Canadian policymakers and grid operators may want to consider going forward. Aspects of performance and functionality that will be considered include:

- Provision of fast frequency response and inertia
- Provision of primary frequency response and headroom
- Provision of balancing and ramping (regulation)
- Provision of reactive power and dynamic voltage regulation
- Provision of black start and system restoration
- Provision of contingency and flexibility reserves

In addition, this task will also briefly discuss the role and value of forecasting in grid operations and the benefits to increasing granularity in energy markets to accommodate increasing amounts of variability and uncertainty.

9.2 Background

In a traditional centralized electric grid, with large base load generators of either thermal or hydro based resources, the need for ancillary services focuses primarily on recovering from an electrical event, primarily due to a trip from a large generator or transmission line.

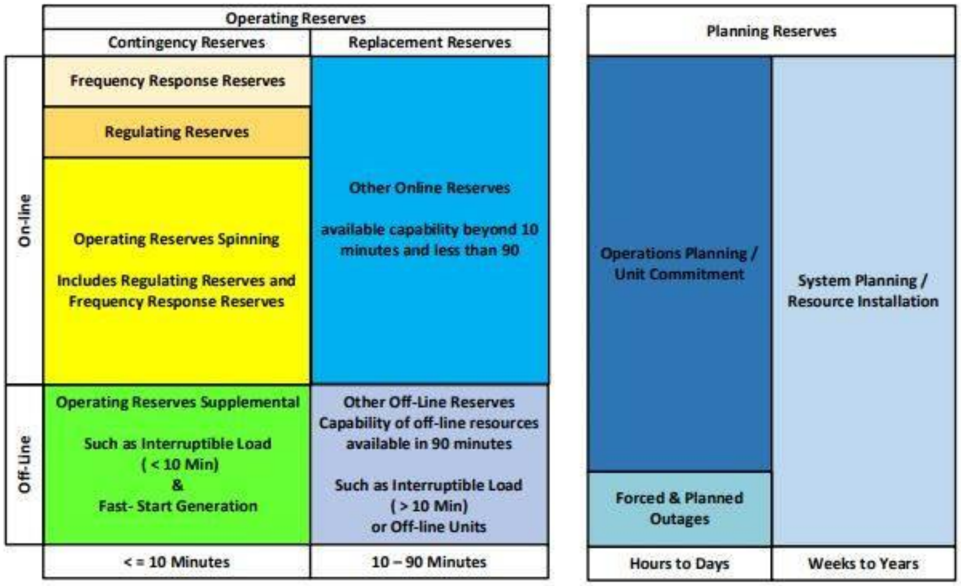
Thermal and hydro generators are able to provide large amounts of inertia to a transmission grid due to the spinning masses of those machines. As such, most generators connected to the grid are required to provide inertia to reduce Rate of Change of Frequency (RoCoF) and primary frequency response (stabilize frequency). In addition to inertia and primary frequency response, generators also provided secondary reserve, e.g. return frequency to nominal and / or Area Control Error (ACE) to zero, and tertiary reserve, or bring back the transmission grid to an n-1 secure state.

As these contingency services are instantaneous or nearly instantaneous, provision of these services are typically required by most grid connected generators and have not traditionally been subject to market mechanisms. Some system operators will reimburse generators for their costs (cost based supply) or provide lost opportunity costs to generators for the provision of reactive supply or voltage control.

Table 24: Traditional Ancillary / Essential Reliability Services

Time From Event	Control Mechanism	Purpose	Typical Market Product Name(s)
~0s-10s	Inertia	Reduce RoCoF post contingency	N/A
~10-30s	Governor	Stabilize Frequency	N/A
~30s	AGC / Market Signal	Recover Frequency	Regulation, Up Regulation, Down Regulation
~10 minutes	AGC / Market Signal	Restore primary reserves	Spinning reserve, synchronized reserve
~30 minutes	AGC / Market Signal	Restore spinning reserves	Non-Spinning Reserve, non-synchronized reserves, supplemental reserves
N/A	AGC / Market Signal	Keep adequate headroom for changes in load	Ramping Reserves

Table 25: Operating and Planning Reserves defined by NERC Operating Reserve Management RG[24]



	Operating Reserves		Planning Reserves	
	Contingency Reserves	Replacement Reserves		
On-line	Frequency Response Reserves	Other Online Reserves available capability beyond 10 minutes and less than 90	Operations Planning / Unit Commitment	System Planning / Resource Installation
	Regulating Reserves			
	Operating Reserves Spinning Includes Regulating Reserves and Frequency Response Reserves			
Off-Line	Operating Reserves Supplemental Such as Interruptible Load (< 10 Min) & Fast- Start Generation	Other Off-Line Reserves Capability of off-line resources available in 90 minutes Such as Interruptible Load (> 10 Min) or Off-line Units	Forced & Planned Outages	
	< = 10 Minutes	10 – 90 Minutes	Hours to Days	Weeks to Years

Most market based ancillary services has historically been limited to Regulation (Balancing and Ramping Reserve) and Contingency Reserves (Synchronous and Non-Synchronous Reserves). These have been traditionally supplied by dispatchable generation (other than solar and wind) as the need to increase generation to cover energy shortfalls or other events has been considered the primary requirement. In normal circumstances, wind and solar are unable to respond to increased generation other than what they are already producing.

However, the ever-increasing penetration of renewables and the intention to move to a net zero carbon future requires as fundamental shift in grid management of renewables in terms of both energy and ancillary services. An example where renewables specifically (not including storage) can respond to energy dispatch and ancillary services is to reduce or curtail generation. This is increasingly a valuable response to grid management, particularly during the overnight and off-peak periods where renewables push thermal and hydro generation towards their minimum generation point or to decommit those units.

Thermal and hydro generation at the minimum generation levels no longer have foot room to reduce generation further, which also impedes their ability to respond to down signals in both energy and the ancillary services markets. These down signals are important during periods when thermal and hydro are at their minimum generation. As renewables can both respond to curtailing generation in the energy and ancillary services markets, bifurcating the ancillary services products into up and down responses is crucial. For example, some grid operators historically had just a single regulation or synchronous operating reserve product.

Generators providing these services were required to provide both up and down regulation, for example. In this circumstance, renewables would not be able to provide regulation as they more often

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[24] "Reliability Guideline: Operating Reserve Management Version 3," Approved by the NERC Reliability and Security Technical Committee on June 8, 2021, https://www.nerc.com/comm/RSTC_Reliability_Guidelines/Reliability_Guideline_Template_Operating_Reserve_Management_Version_3.pdf#search=operating%20reserve

than not could not respond to the up signal. Splitting regulation in two separate products, an up-regulation and a down-regulation, opens the regulation to renewables as they can now respond to down regulation signals. The same is true for the other market-oriented reserve products like synchronous reserves. Furthermore, once renewables have been curtailed, they have now created headroom to which they can also respond to increasing generation requirements in both the energy and ancillary services markets, a prerequisite to participating. This is currently done today in Nova Scotia.

9.3 REMOVING BARRIERS FOR INVERTER BASED GENERATION

In the evolving (non-traditional centrally dispatched) grid, inverter-based generation (most often solar and wind generation as well as battery storage) are increasingly able to provide essential reliability services to support voltage and frequency, balancing and ramping. This is a relatively new entrant as a provider of ancillary services and current best practice is changing rapidly. While inverter-based resources can provide a number of different reserves, there remains number of barriers to their participation.

Market and operational barriers include:

Aggregation of DER

Aggregation of DER and behind the meter solar PV, can provide meaningful input into energy and ancillary services. However, due to the size and sheer number of smaller scale behind-the-meter and DER resources, these resources should be marshalled through aggregators in order to manage the large volume of data required to manage these assets. Aggregation will make the interface with the system operator much easier to handle. As DER aggregation becomes more prevalent, grid codes play an increasingly important role to specify visibility, data exchange, modeling and control of aggregated resources on the grid.

Negative Energy Pricing

Allowing negative energy prices (LMP) and ancillary services in market construct. A number of ISO's have recently moved from zero dollar energy price floors to allowing negative pricing (ISO New England is a recent example). This is key to markets with a growing proportion of renewable generation which typically bid at zero or negative prices. It is not uncommon to find wind generation in the U.S. to bid their energy at negative $30/MWh, which equates to the benefit of the tax benefits they receive.

Furthermore, negative prices allows thermal plants to appropriately bid the price point at which they would rather shut down than continue generating. This is particularly important in markets with nuclear units which are unwilling to shutdown, and therefore will operate at almost any price point. This is compared to coal or natural gas turbines which are relatively more flexible in terms of start and shut down decisions and as such have a higher price threshold incurring losses.

Without this negative price distinction, how do system operators decide which plant to force down first during a low net load event. Secondly, the negative prices provide appropriate market signals to new entrants, particularly battery storage which can provide relief to low periods of load by charging their batteries and taking advantage of negative pricing in their arbitrage bidding.

Co-optimization

Ancillary Services prices should be co-optimized with energy in both day ahead and real time markets. Co-optimization of energy and ancillary services ensures that all resources in markets are paid for the service that they provide and are not penalized for providing one service over another. For example, generators providing ancillary services should not be penalized during periods of shortages in the energy market when there are high energy prices. Only through co-optimization of both energy and ancillary services ensures that generators are not forced to choose from providing one market over the other.

Disaggregation of ancillary products

As already discussed, disaggregation of ancillary products in their component parts is key to allowing other assets to providing ancillary services. This is not limited to just separating regulation or spinning reserves into an equivalent up and down product. It also includes disaggregating ancillary services into fast response (see discussion of Fast Frequency Response and Inertia below) and paying for higher quality services.

Incentivizing Quick Response and Higher Quality Ancillary Services (Changes to ancillary service products which specifically incentivizes IBRs will help close the gap in the provision of ancillary services. See discussions on ERCOT and PJM below).

Price Hierarchy and Product Substitution

It is important as new ancillary service products are introduced with an appropriate price hierarchy and product substitution is maintained. This is common in many ISO market for ancillary service products. For example, an ISO might have a total contingency or flexible reserve requirement of 1000 MWs, composed equally of spinning and non-spinning reserve of 500 MW each. However, during periods of high demand with a large number of generators online, it is possible to meet the entire reserve requirement of 1000 MW with the higher quality spinning reserves, displacing all of the lower quality non-sync. As such, higher quality ancillary services should always be allowed to replace lower quality ancillary services and assuming this is done with the appropriate prices. Alternatively, the lower quality non-synchronous reserve should not be able replace the 500 MW of spinning reserve requirements. Prices will follow the higher versus lower quality reserves appropriately.

Shortage Pricing

Shortage pricing is another mechanism which has been adopted in some ISO administered markets and should be expanded through all markets. In New York, when there is a shortage of any of the reserve products (spinning, non-sync or regulation), then a shortage pricing mechanism kicks in. For low levels of shortages, the prices are relatively modest. As shortages increase both in volume and quality of ancillary services, then the shortage prices reach levels expected of shortages in the energy market of $1200 / MWh. This is relevant, as shortages in ancillary services are typically are harbinger to shortages in the energy market itself. It is important to set appropriate price signals (again with co-optimization between energy and ancillary services) during shortage periods, even if for short durations. Shortage pricing are appropriate market signals to both generation and load new entrants.

Technical barriers for resources providing ancillary services include:

- Headroom or footroom to maneuver MW output during normal operation to provide frequency regulation (secondary response)
- Headroom or footroom to maneuver MW output during grid events to provide primary frequency response
- Active power and reactive power regulator tuning and operational status to provide appropriate response

9.4 Provision of Fast Frequency Response and Inertia

Systems with high penetration of renewables have started to experience declines in inertia capabilities. A recent study published by ERCOT in 2018, which has a high incidence of wind as well as increasing solar PV, indicates a high correlation between declines in net load (load less renewable generation) and inertia.[25]

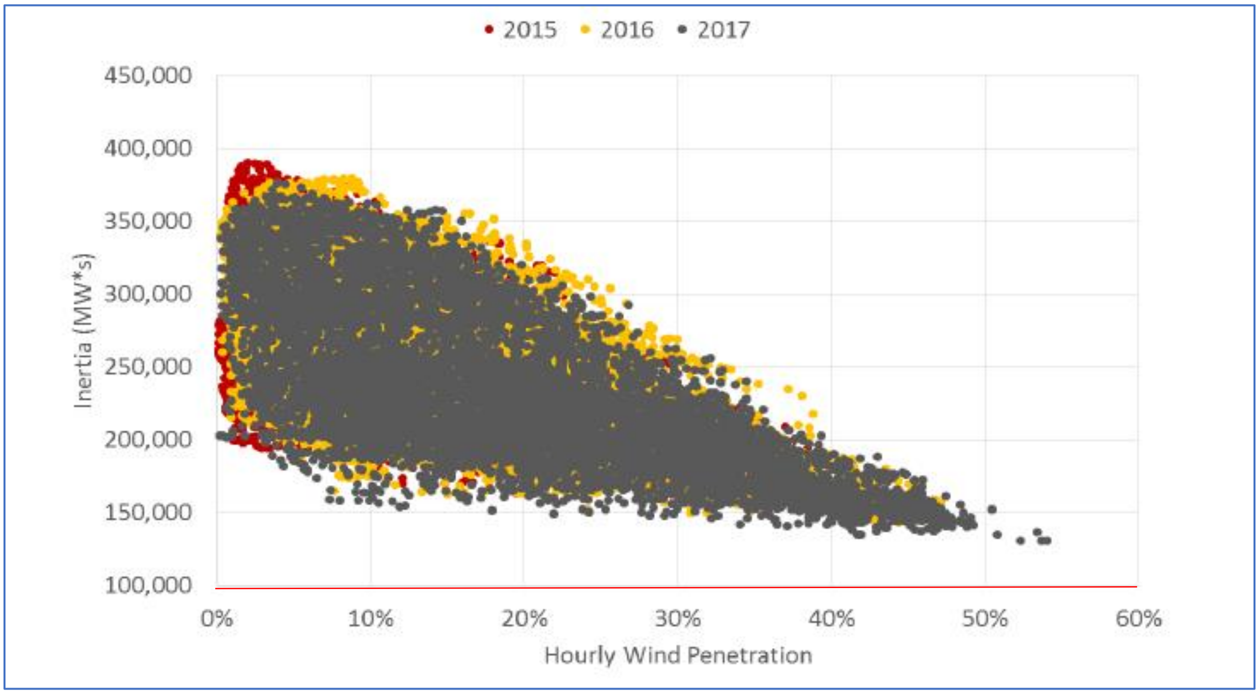

Figure 34: ERCOT Correlation between Wind Penetration and Inertia in 2015, 2016, and 2017

This is particularly problematic during periods of low load, when large portions of thermal generators and the largest providers of inertia via synchronous machines, are backed down or de-committed in the energy market.

In response to this declining inertia and Fast Frequency Response (FFR), ERCOT has introduced new ancillary service products designed to assist with this issue [26]. This augments the inertia that ERCOT maintains on their grid. Operators act if the inertia passes below 100GW-s by deploying non-spinning reserves.

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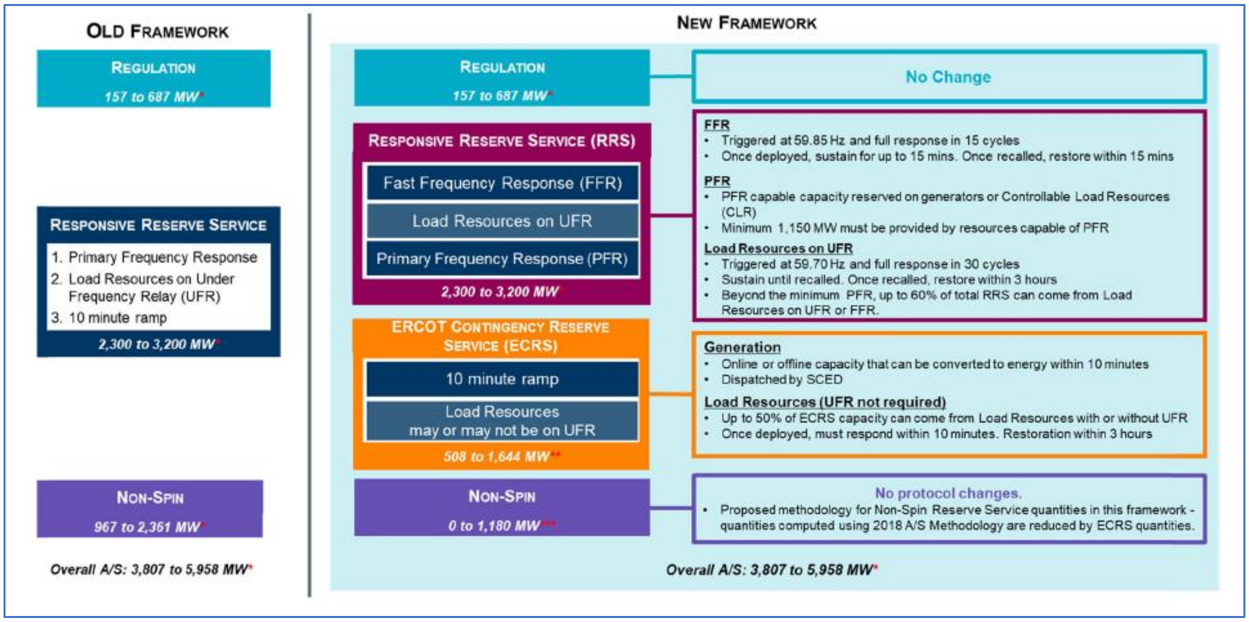
[25] Inertia: Basic Concepts and Impacts on the ERCOT Grid, ERCOT, 2018

[26] New Ancillary Service Market for ERCOT, IEEE POWER & ENERGY SOCIETY SECTION, October 9, 2020.



FFR
- Triggered at 59.85 Hz and full response in 15 cycles
- Once deployed, sustain for up to 15 mins. Once recalled, restore within 15 mins

PFR
- PFR capable capacity reserved on generators or Controllable Load Resources (CLR)
- Minimum 1,150 MW must be provided by resources capable of PFR

Load Resources on UFR
- Triggered at 59.70 Hz and full response in 30 cycles
- Sustain until recalled. Once recalled, restore within 3 hours
- Beyond the minimum PFR, up to 60% of total RRS can come from Load Resources on UFR or FFR.

Generation
- Online or offline capacity that can be converted to energy within 10 minutes
- Dispatched by SCED

Load Resources (UFR not required)
- Up to 50% of ECRS capacity can come from Load Resources with or without UFR
- Once deployed, must respond within 10 minutes. Restoration within 3 hours

- Proposed methodology for Non-Spin Reserve Service quantities in this framework - quantities computed using 2018 A/S Methodology are reduced by ECRS quantities.

Figure 35: ERCOT New Ancillary Service Products to Address Declining Inertia

The left side of Figure 35 depicts the previous Ancillary Services provided in ERCOT, which is typical of the ancillary services products many Independent System Operators (ISOs) in North America have offered, and the right side depicts the new framework.

The primary distinction in the new framework is the response time for each reserve. In the old framework, the Responsive Reserve Service (RRS) was basically a 10-minute spinning reserve. If the frequency dropped below the ERCOT threshold of 59.91 Hz, the generators obligated to provide RRS (based on day ahead commitments) "would be released into the security constrained economic dispatch (SCED)" in real time. Because this is a "one-size-fits-all" approach, there was little distinction or reward to provide fast response.

Under the new system, "RRS (old) will be unbundled into two products: RRS (new) and ECRS. RRS (new) includes three subsets: PFR, LRs and FFR. All three RRS subsets are procured with an intention to arrest large frequency excursions following a generation trip." The IEEE paper[26] by ERCOT describes the requirements of FFR as follows:

- To be qualified for the provision of FFR, a resource should be able to be automatically deployed and provide its full response within 15 cycles after the frequency meets or drops below a preset threshold (59.85 Hz) or be deployed via a verbal dispatch instruction (VDI) within 10 minutes. FFR resources must sustain a full response for at least 15 minutes once deployed. When a resource providing RRS as FFR is deployed, it shall not recall its capacity until the system frequency is greater than 59.98 Hz or they have been sustainably deployed over 15 minutes. Once recalled, the resources providing FFR must restore their full FFR responsibility within 15 minutes after the cessation of deployment or as otherwise directed by ERCOT.

One of the specific target segments for these new ancillary services is battery storage. Again, the ERCOT paper describes the changes to encourage new storage participation:

- The past market rules at ERCOT required that RRS should be deployed within 10 minutes upon the receipt of the deployment instructions. This requirement does not explicitly incentivize the resources which can quickly deliver the primary frequency response.

This is one example of the opportunities for markets to adopt to the evolution in generation and the need to support inertia through adaptation. ERCOT well adapted the new requirements to account for evolving equipment capabilities.

9.5 Provision of Primary Frequency Response and Headroom

As increasing renewables displaces synchronous machines, battery storage is going to be a key new entrant in providing primary frequency response. The provision of primary and secondary frequency response requires:

1. Governors enabled and tuned to respond
2. A signal from the grid operator to balance load (AGC)
3. Adequate headroom and footroom to maneuver

Unit commitment and dispatch will highly influence which units are online and available or capable to respond to frequency. Not all units will respond with the same performance. It will also highly influence how much headroom and footroom is available to respond to under- or over frequency events. Design of ancillary markets should account for the provision of the 3 elements outlined above to make sure units participating in primary frequency response and regulation have adequate capability to do so. Markets should account for the cost of securing room to maneuver when needed.

9.6 Provision of Balancing and Ramping (Regulation)

As discussed in the previous section, the provision of both Regulation and Contingency or Flexibility Reserves should be extended to renewables and inverter-based generation. Any rule / market changes necessary should be incremental to encourage this new segment.

For DER, aggregation of generator resources should be vital to managing the volume of smaller scale micro generators. At this level, participation should not be mandatory, at least not initially. As renewables expand, particularly behind the meter roof top solar, plans should be developed how this sector could participate in the future, particularly in terms of metering and other obligations so that developers can manage buildout accordingly.

For utility scale inverter-based generation, the tools should already be available to allow these resources to participate in regulation. The key to participation is to design the regulation product that wind, solar and DER resources can easily step into. Bifurcation of regulation into up-and down-regulation is a good first step. Other developments can include creation of higher qualitative regulation products. Note that these higher qualitative products should be follow price hierarchy and product substation described above.

PJM has taken this route with the introduction two regulations products: Regulation A and Regulation D. PJM describes these two regulation products with a transportation analogy: Regulation A can be thought of as a large bus which is able to transport a lot of people, albeit slowly; Regulation D can be thought of a small passenger car which can move nimbly and quickly but only carry a few passengers.

"PJM generates two different types of automated signals that Regulation Market resources can follow. The Regulation D signal is a fast, dynamic signal that requires resources to respond almost instantaneously. Regulation A is a slower signal that is meant to recover larger, longer fluctuations in system conditions. These two signals communicate with each other and work together to match the system need for regulation."[27]

Generators providing both Regulation A and D follow an Automated Generator Control (AGC) signal sent by PJM to each resource owner. Regulation D was designed for storage to be able to follow more dynamic signals. In this instance, the signals are dynamic signals which moves with the frequency deviation component of ACE. This increases the "utilization" of the energy storage devices.

In addition, PJM also provides performance-based compensation for regulation [28]. Performance scores reflect how well the resource is following the regulation signal. PJM scores resources on three components:

1. Accuracy: the correlation or degree of relationship between control;
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.

By expanding the regulation into a high quality and high-volume products and simultaneously providing compensation for performance, PJM has expanded the resource base which can provide regulation to other resources while also providing a mechanism to ensure reliability of the product. This is a great example of the market and operational designers for PJM catering change to the regulation market to match the capabilities of the new entrants.

9.7 Provision of Reactive Power and Dynamic Voltage Regulation

Reactive power capability and voltage support is typically a required service specified by a grid code. Resources must provide this service to connect to the grid. The earlier sections of this report call out typical reactive power and voltage regulation requirements. However, there are certain areas that consider enhanced reactive power supply and voltage support an ancillary service. Two examples are New York (New York Independent System Operator) and IESO in Ontario, Canada. If additional reactive support is needed beyond the base requirement, entities may bid in to provide enhanced reactive capability and voltage regulation. Additionally, for resources that are capable to provide it, ancillary market mechanisms for providing voltage regulation at zero active power output are also an effective and efficient means to stabilize the voltage under all grid conditions.

9.8 Provision of Black Start and System Restoration

Inverters can be adopted to include capability for grid forming, allowing certain assets to provide black start and system restoration. This would be primarily the domain of batteries or other storge capabilities. While battery storage systems deployed in bulk power systems are typically based on grid following technology, there are few exceptions of MW-size battery systems based on grid forming

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[27] PJM https://learn.pjm.com/three-priorities/buying-and-selling-energy/ancillary-services-market/regulation-market.aspx

[28] https://www.pjm.com/~/media/committees-groups/task-forces/rmistf/20160413/20160413-item-02-performance-scoring.ashx

technology. The development effort and cost of deploying Inverter-Based Resources (IBR) to accommodate grid forming technology is highly dependent on the performance requirements of the asset.

An example of this is a project in California at the Imperial Irrigation District (IID). This project includes a gas turbine and BESS with 30MW / 20 MWh. In this case, a BESS with grid forming controls can be utilized to start the gas turbines which can then be used for black start. There are additional examples of BESS providing black start or grid forming capabilities in Hawaii.

One possible limitation of stand-alone batteries providing black start is it may disrupt their capabilities to provide more valuable services like energy and other ancillary services. This technology, as compared to hydro based resources, is disadvantaged from the respect of not being able to guarantee it would have a full charge available during a system restoration point, particularly if the batteries were discharged in efforts to maintain the management of the grid prior to the need of black start. As such, from an operational viewpoint, provision of black start and system restoration is an ancillary service which is typically designated to one large-scale generator, which can start independently of its connection to the electrical grid. While Black Start can be a cost-based supply service, due to the limitations of generators participating, it is not normally conducted in a dynamic or auction-based market.

9.9 Provision of Contingency and Flexibility Reserves

Similar to regulation, the provision of contingency and flexibility reserves should be expanded to include IBRs. Splitting spinning reserves into spin-up and spin-down should attract segments of these resources. For example, **batteries or storage** can serve both energy and spin up when the units are discharging and "generating" and can serve both load and spin down when charging. While it is feasible for batteries to provide non-sync when they are not providing generation or load, other inverter-based resources such as solar and wind cannot provide non sync reserve. This is due to the variability of their generation and cannot necessarily start generation as synchronous reserve during an event.

Once IBRs are dispatched in the energy market and their generation can be curtailed, this opens the opportunity for these resources to have headroom and to provide up-spin and up regulation as well.

10 REVIEW AND IDENTIFICATION OF UPDATED PLANNING PRACTICES AND SYSTEM STUDIES TO ACCOMMODATE HIGHER PENETRATIONS OF VARIABLE ENERGY AND INVERTER-BASED RESOURCES

10.1 Canada’s decarbonization challenge

Around the world, new mandates are continuously emerging promoting deeper and deeper levels of decarbonization. As Figure 36 shows, these goals appear in many shapes and sizes: carbon vs. renewable outcomes, different entity types, different decarbonization levels. But one theme is common*: **Many of these goals are being set before planners have determined out how to practically implement them.***

Figure 36: Decarbonization goals around the world by countries, states, utilities.

In late 2020, the Canadian Minister of Environment and Climate Change proposed legislation to transition Canada to a net-zero emissions economy by 2050 with legally binding interim targets starting in 2030[29]. A recent report by the Canadian Institute for Climate choices assesses potential pathways to net zero[30] Figure 37 shows one of the scenarios the Climate Choices team modeled. This modeling highlights how decarbonization of the electric sector will be minor compared to decarbonization of end-use sectors like industry. However, it is important to note that electrification is one of the top pathways they outline. Electrification will only have a carbon benefit if the electric mix supports it.

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[30] “Canada’s Net Zero Future” by Canadian Institute for Climate Choices (Feb 2021) https://climatechoices.ca/wp-content/uploads/2021/02/Canadas-Net-Zero-Future_FINAL-2.pdf

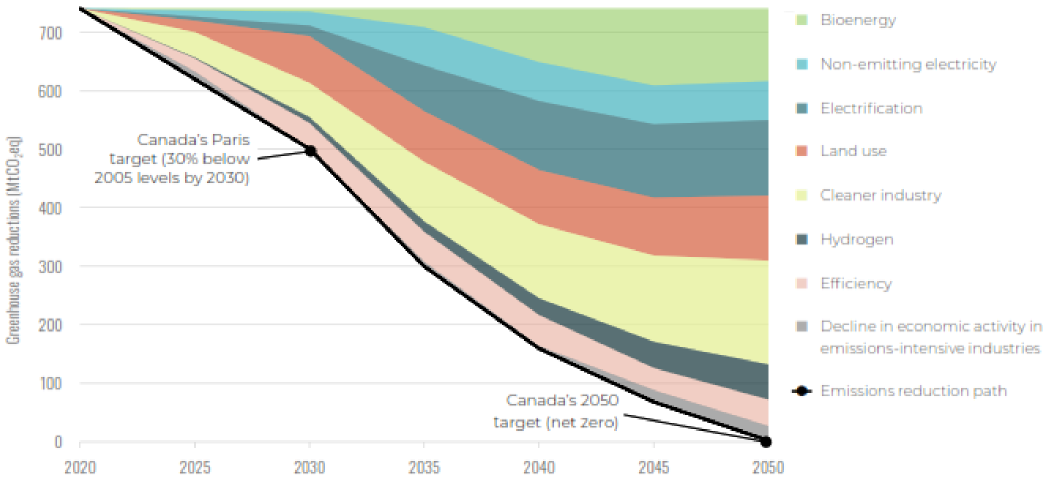

Figure 37 Graph from recent report released by the Canadian Institute for Climate Choices outlining one scenario for reaching 2050 net zero. Decarbonizing the electric sector is relatively small compared to decarbonization of the end-use sectors.

Figure 38 shows Canada's national generation mix in 2020 showing that 20% of the mix is from carbon-producing sources like coal (10%) and natural gas (10%). The level of variable renewables is quite small at 5%.

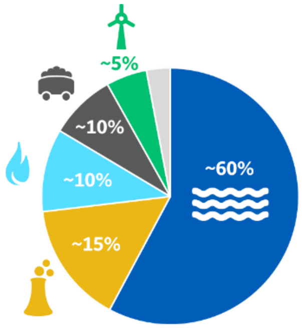

Figure 38 2019 Canadian generation mix (TWH)[31].

The GE team has modeled a nameplate capacity outlook for seven of the ten Canadian provinces as shown in Figure 39. If the net zero by 2050 goals become binding, decarbonization burden would fall more heavily on the provinces shown toward the right side of the chart.

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[31] BP Statistical Review of World Energy (June 2020)

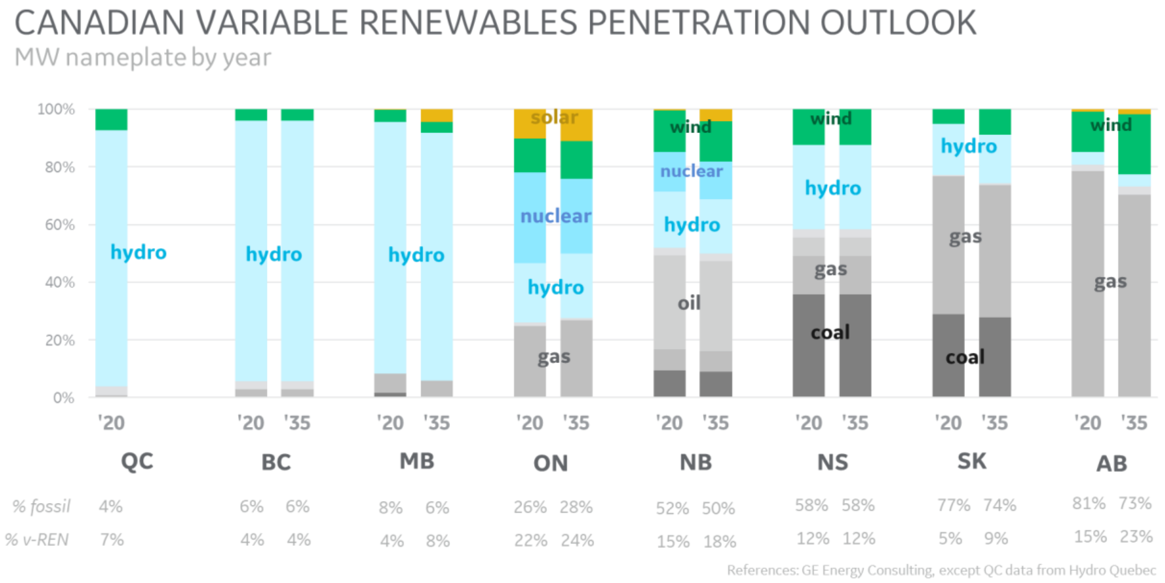

Figure 39 2020 vs 2035 nameplate capacity across Canadian provinces. 2035 forecasted views are from GE Energy Consulting analysis and considered current binding policies. (ref: GE Energy Consulting, Hydro Quebec)

Closing the fossil gap will require new carbon-free sources of electricity across the prairies and the Maritimes. New hydro and nuclear are often more difficult to build versus new wind and solar. New transmission options from hydro-rich provinces can also help but could it be enough to close the fossil gap? Hence, **decarbonization of the prairies and Maritimes will likely require record amounts of wind and solar energy.**

By 2035 in Alberta, for example, the GE team forecasts that the fossil gap will decrease to 73% on a nameplate basis due to the increase in wind to 23%. GE's 2016 study showed that Alberta can accommodate up to 50% wind on a generation basis[32] with greater transmission connections to neighbors. However, full decarbonization and electrification will likely need more than that.

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[32] https://canwea.ca/wp-content/uploads/2016/10/pcwis-alberta-summary-web.pdf

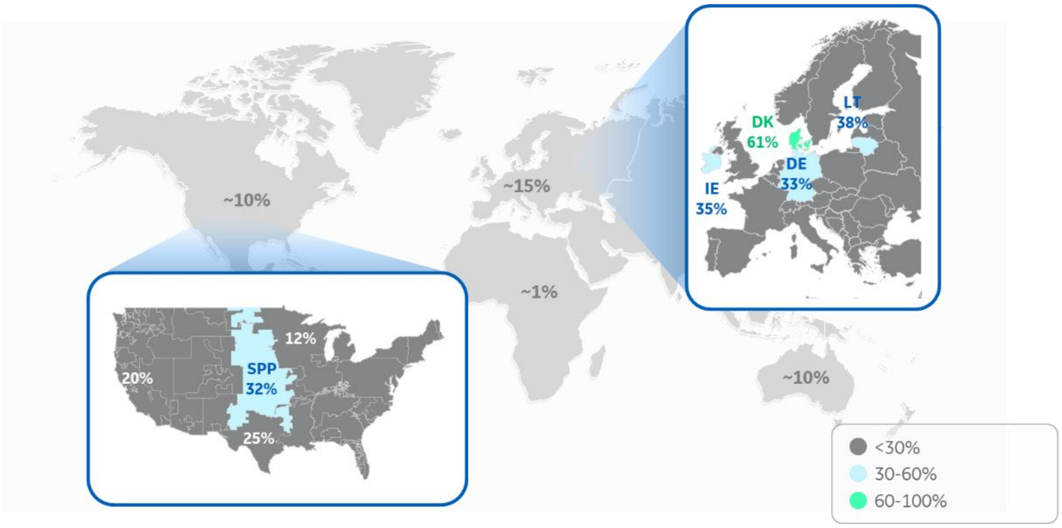


Figure 40 2020 annual average wind and solar generation penetrations across the US and Europe (ref: ABB, ENTSO-E).

As a reference, Figure 40 shows 2020 levels of variable renewable generation penetration across the US and Europe. **Denmark currently has the highest penetration levels at 61%,** while Lithuania, Germany, Ireland and SPP are all between 30-40%.

Our purpose in highlighting these trends is as follows: while at a national level, full decarbonization of the electric sector seems small compared to other sectors, if indeed Canada does move towards binding net-zero targets, certain provinces will likely carry a higher burden. The levels of wind and solar likely required to close the gap in provinces like Alberta are just starting to emerge in Europe where countries are more interconnected than across Canada. **Hence full decarbonization of Canada's prairie and Maritime electric sectors would likely require new global records for wind and solar penetration.**

10.2 Decarbonization using variable renewables encompasses three types of transformations

Certainly a Canadian net zero carbon goal with new milestones for wind and solar is transformative in in its own right, but an additional level of complexity comes with the fact that successful implementation requires reconciling several additional system transformations as depicted in Figure 41. While policy makers are focused on the high-level carbon goal, system operators, are faced with three additional transformations:

1. An *operations* transformation: **constant-fuel to weather-dependent fuel.** Operators are used to generators with fuel sources that are almost always available when needed. Wind resources are uncertain and vary their availability with the weather. Thus a system with significant amounts of its energy coming from wind means that operators will need to adopt new practices to accommodate energy coming from a variable and uncertain fuel source.

2. An *economics* transformation: **fossil-based energy prices to zero-cost energy prices.** Energy prices have typically been based on the cost of fossil fuel sources like natural gas and coal. Given that wind resources are zero variable cost, a market with 70% of its energy coming from wind will lead to energy markets with lower energy prices.
3. A *physics* challenge: **synchronous machines to inverter-based resources.** For the last 100 years of our electric system, frequency and voltage has been maintained by synchronous machines: rotating steam or gas turbines that mechanically drive an electrical generator to create electricity. Wind turbines, solar panels, and batteries all drive power electronic, inverter-based electrical generators which maintain frequency and voltage in a fundamentally different manner. A wind-based system, is a fundamentally new inverter-based system.

All three of these transformations are now happening simultaneously. However, do the departments responsible for planning each of these three transformations collaborate? Are their planning tools integrated? Herein lies the real decarbonization challenge. Not only are government policies preceding implementation plans, but the entities responsible for implementation often work on their own part of the system with historically siloed planning practices. We have found that in many cases, these departments are not even allowed to meet and share information even if they wanted to.

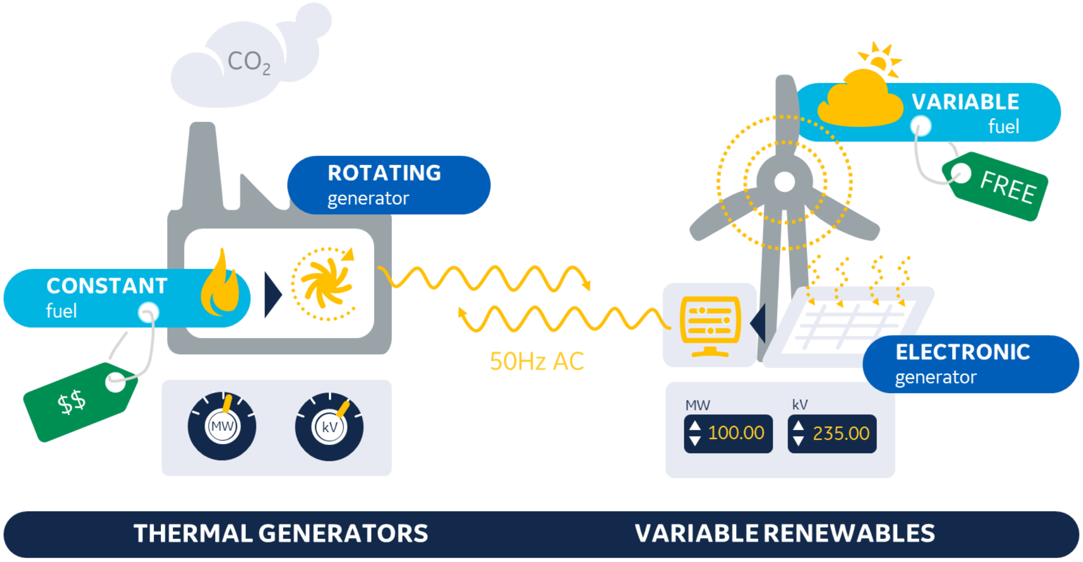


Figure 41 The energy transition from thermal to variable renewables is more than just a carbon transition. It's a transition in how we utilize fuel, design markets, and maintain grid physics.

Achieving a reliable and economic system across the prairies and Maritimes with mostly **weather-dependent, inverter-based, zero-marginal cost resources on an electrical island is one of the toughest energy challenges** on the planet. Success will require a fully *integrated* planning process. It is this process that the GE Energy Consulting team will describe our thoughts on here in order to facilitate discussions regarding an appropriate path forward.

10.3 The need for integrated & holistic system planning

10.3.1 The traditional integrated planning approach

How does your electrical system operator typically plan for the future? In our experience with system operators around the world, before the growth of variable renewables, this process has often looked quite linear as shown in Figure 42. However, as renewables have grown, many system operators are currently transitioning away from this traditional approach toward the iterative approach we describe in Section 10.3.2. We describe both approaches here in order to share our thoughts on the differences.

In the traditional integrated planning approach shown in Figure 42, there are three major output products produced in this process:

1. **Reserve margins** based on load growth and uncertainty of both the load forecast and resource availability.
2. A **generation expansion plan** based on reserve margins in (1), technology + fuel costs, peak load growth, and policy needs.
3. A **transmission plan** based on the generation plan in (2), along with consideration of existing codes and standards.

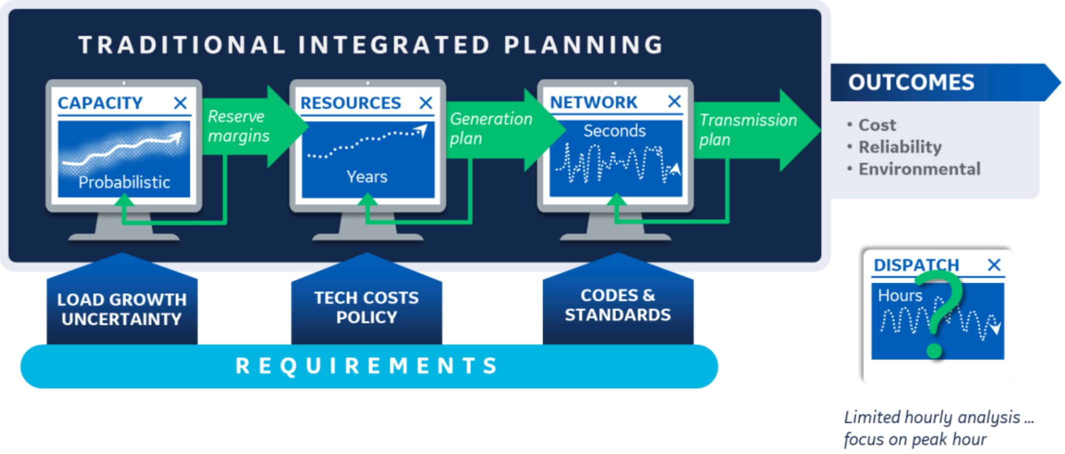


Figure 42 Traditional integrated planning process ... a linear approach.

Though this process has worked well for the last 20-30 years of our industry, there are two main challenges with this approach:

1. **Planning steps are typically siloed.** As you can see from Figure 42, the output from each planning step (i.e. capacity planning, resource planning, network planning) feeds the next planning step. Each step is often performed in relative isolation. For example, generation planners generally assume that the network reliability of the system is not a consideration in resource decisions. At the same time, network planners typically do not consider resource expansion alternatives to mitigate network reliability needs they identify. The challenge if grid planning processes are siloed in this way, is that each department assumes their decisions do

not affect and are unaffected by the others. While this has been a fair assumption in the past, with a generation mix transforming as rapidly as it is now, this assumption no longer suitable.

2. **Planning practices focus on *peak* hours as the top hours of risk.** The traditional planning approach also centers around the assumption that the most risky period of time for grid reliability is the hour of peak load. Reserve margins are typically determined based on load forecast uncertainty and resource availability during *peak* load hours. Generation plans have historically focused on the lowest cost resources to meet *peak* load. Network plans are based on a range of technical models that represent various aspects of power flows during *peak* hours. Again, this planning practice was adequate in the past because the riskiest hour for the grid was indeed during peak. However, with a system transitioning towards higher reliance on weather-dependent generators whose output varies hour-to-hour, the riskiest hour may no longer be during peak. The traditional planning approach depicted in Figure 42 rarely includes hourly analysis to help identify other non-peak hours of high risk—a major flaw going forward.

10.3.2 The iterative integrated planning approach

In a deeply decarbonized grid system that is transitioning from synchronous, fossil-based resources like gas and coal, to inverter-based variable weather-dependent resources like wind and solar, there are several fundamentals changing simultaneously as depicted in Figure 41:

1. **New hourly risks**: Peak load risk -> Weather-related, non-peak risks
2. **New market risks**: Non-zero marginal cost energy prices -> Zero marginal cost energy prices
3. **New physics-based risks**: Synchronous machines -> Inverter-based machines

The traditional integrated planning process shown in Figure 42 generally overlooks these transformations since historically, none of these changes were factors to consider. However, given that many regions are currently in the middle of all three of these transformations at the same time, our planning practices must transform accordingly.

Figure 43 The iterative & integrated planning process for deep decarbonized grid systems with high penetrations of variable, inverter-based renewables.

Instead of a siloed approach, GE Energy Consulting recommends a more integrated approach as shown in Figure 43. Given that the approach here is more circular in nature, there is no perfect starting place. However, here is a suggested approach based on our project experience to date.

Step 1: Formulate 2030 baseline resource mix scenarios

We suggest the process begins by formulating a few baseline scenarios based on the current view of system requirements (e.g. load growth, policy, technology cost), along with a number of resource mix options that meet the high-level outcomes of the system. Each scenario would represent a different pathway to meeting the decarbonization target but may present differing risks in terms of resource adequacy, network reliability, and cost. These baseline scenarios would also include baseline views of ancillary service requirements which will be evaluated in later steps of this approach.

Step 2: Develop 2030 optimized scenarios

Once the baseline resource mix scenarios have been established in Step 1, the study team would perform an "iterative assessment" as shown in Figure 43 to identify additional reliability risks across the various timescales of system operation. The iterative assessment involves a circular process that uses production cost modeling, network modeling (i.e. load flow, stability, control performance analysis), and adequacy assessment using the baseline scenarios as a starting point. This circular process would proceed through the following four steps to holistically optimize the scenarios.

Step 2 (a): Production dispatch simulation & screening to identify non-peak intervals of risk

One of the top differences introduced by the iterative approach is the use of hourly production cost modeling to **identify the new intervals of time in which reliability risks are a concern**. Given the variable nature of wind and solar resources, the economic dispatch of renewable and non-renewable units influences several factors that are critical to reliability across all hours of operation. Identifying those intervals of concern is a key ingredient to subsequent planning steps.

Once we have simulated the dispatch of the system across the baseline scenarios, an additional screening step is often necessary to select the intervals of time that warrant deeper risk assessment. In our experience, the following are some of the top factors we consider for our screening:

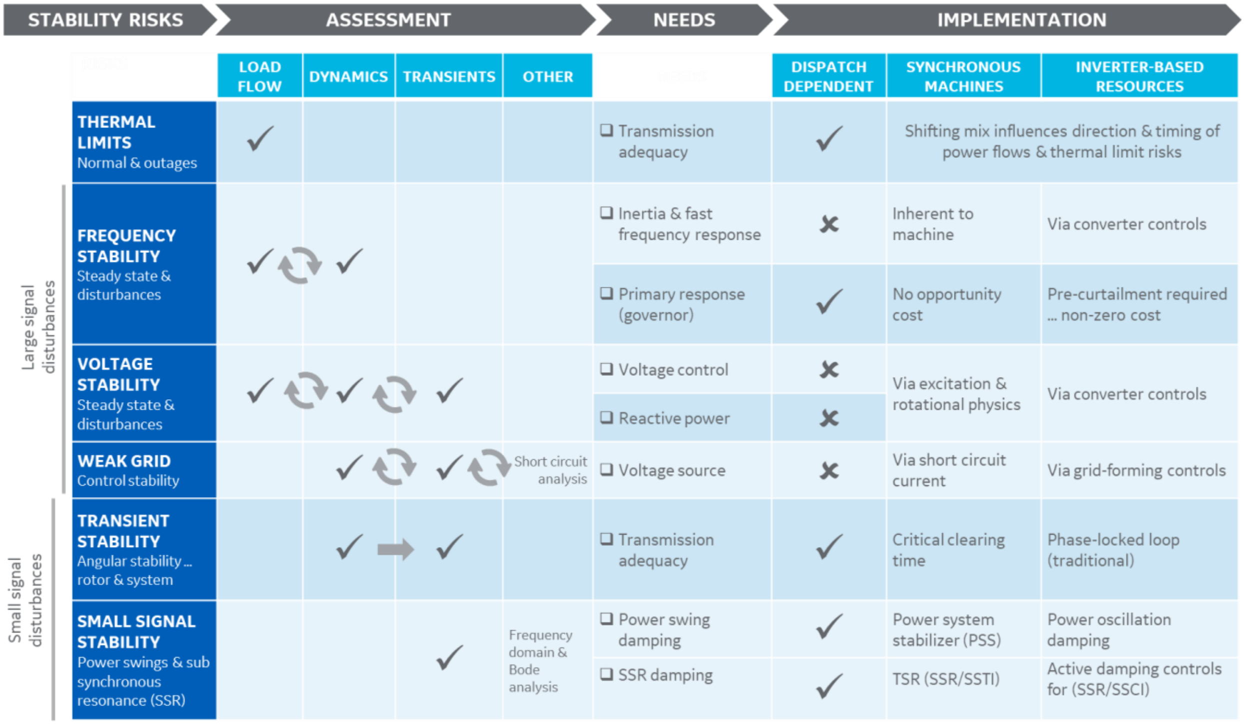
- **Peak net load** (Load minus variable renewables)
- **Peak renewables** (i.e. peak non-synchronous generation)
- **Significant levels of curtailment** (spilled) renewable energy
- Significant levels of transmission **congestion**
- **Unserved energy**
- Periods of high wind and solar **forecast error** (our production cost simulation includes an element of forecast uncertainty)
- Periods of high net-load **ramping**
- Periods of **low headroom** across synchronous units
- Significant **energy exchanges** with neighboring systems

- Utilization of spinning **reserves** and real-time unit **load following**
- Ability of resources to support voltage and frequency during **disturbances**
- Ability of **inverter-based resource controls** to remain stable and support grid needs under all operating conditions and during disturbances

Given that several of the items above may not be directly observed in production cost simulation results, we continue to develop ways to identify dispatch conditions under which they would most likely be a risk.

Step 2 (b): Network simulations to identify reliability needs

Once the intervals of high reliability risk have been identified through the production cost analysis, the dispatch conditions during these intervals can be used to further assess network reliability risks. These risks can span various timeframes and operating conditions, each with their own analysis framework as summarized in Table 26.



	STABILITY RISKS	ASSESSMENT				NEEDS	IMPLEMENTATION		
		LOAD FLOW	DYNAMICS	TRANSIENTS	OTHER		DISPATCH DEPENDENT	SYNCHRONOUS MACHINES	INVERTER-BASED RESOURCES
	THERMAL LIMITS Normal & outages	✓				☐ Transmission adequacy	✓	Shifting mix influences direction & timing of power flows & thermal limit risks	
Large signal disturbances	**FREQUENCY STABILITY** Steady state & disturbances	✓	✓			☐ Inertia & fast frequency response	✗	Inherent to machine	Via converter controls
						☐ Primary response (governor)	✓	No opportunity cost	Pre-curtailment required … non-zero cost
	VOLTAGE STABILITY Steady state & disturbances	✓	✓	✓		☐ Voltage control	✗	Via excitation & rotational physics	Via converter controls
						☐ Reactive power	✗		
	WEAK GRID Control stability		✓	✓	Short circuit analysis	☐ Voltage source	✗	Via short circuit current	Via grid-forming controls
Small signal disturbances	**TRANSIENT STABILITY** Angular stability … rotor & system		✓	✓		☐ Transmission adequacy	✓	Critical clearing time	Phase-locked loop (traditional)
	SMALL SIGNAL STABILITY Power swings & sub synchronous resonance (SSR)			✓	Frequency domain & Bode analysis	☐ Power swing damping	✓	Power system stabilizer (PSS)	Power oscillation damping
						☐ SSR damping	✓	TSR (SSR/SSTI)	Active damping controls for (SSR/SSCI)

Table 26 Common network risks under high inverter-based resource penetration along with the analysis framework and pathways for mitigation. Mitigation for many of these risks depends on the level of unit dispatch such that adequate study needs to be coordinated with hourly production cost analysis.

Table 26 represents a small sampling of the **six most common network risk types we observe and study under high penetrations of inverter-based resources** and the typical analysis tools used to evaluate these risks. Several of these network risk areas warrant their own iterative assessment analyses, especially between steady state load flow and dynamic simulations.

The goal of the risk assessment is to **identify where there are reliability issues and then identify the system needs in order to mitigate**. The typical needs for each risk area are identified in Table 26 as well. For each of these needs, while synchronous machines and IBRs both have pathways for meeting each need, the underlying physics are different and need to be understood. For example, regarding inertia and fast frequency response, synchronous machines provide this service via mechanical rotation, while IBRs provide this service via converter control algorithms. Hence the behavior and reliability impacts may vary between the two.

One of the most important considerations is the fact that **mitigation of network reliability risks can depend on energy market commitment and dispatch** of units. As an example, during a major outage causing a frequency drop, the ability to provide primary frequency response will depend on whether the unit was committed in the energy market and whether it was dispatched to a level that enables adequate headroom. It also depends on the speed and capability of governor response of that committed unit. As zero-marginal cost resources displace synchronous generators during all hours of operation, it is critical to assess whether enough primary response can be maintained via the energy market commitment and dispatch. Studying only the traditional worst-case peak load/light load planning scenarios are increasingly insufficient to identifying such reliability risks. Hence GE Energy Consulting recommends taking a comprehensive approach to analyzing all system conditions that may pose a risk and identifies equipment-related and operational mitigation measures to address grid needs as IBR penetrations grow.

It is in this step that the team will begin to define an "optimized system scenario" by recommending suitable mitigations to address the risks identified. These mitigations may include upgrades to the network or operational improvements such as:

- Transmission **network upgrades** (e.g., interconnection points, voltage level, and rating, AC or HVDC etc.)
- Power **plant modifications**/upgrades: faster ramp rates, deeper turndown, faster startup, etc.
- **Voltage support** upgrades (e.g. synchronous condensers, FACTS devices)
- **Damping** (e.g. power system stabilizer tuning, power oscillation damping)
- **Inverter controls** tuning (e.g. frequency, voltage controls)
- **New technologies** (grid forming controls, role of hybrid power plants and energy storage)

Some of the mitigations listed above may require more detailed modeling and analysis to fully capture the implementation requirements and benefits. These needs can then be realized through two main grid operator mechanisms:

1. **Grid codes and requirements.** Most of the needs identified in Table 26 are typically implemented via grid codes and requirements today. The advantage of this approach is that the grid operator can clearly specify what is required for each resource in a pass/fail manner. However, this approach is rarely associated with economic compensation. This is especially challenging for wind and solar IBRs providing primary frequency response since uneconomic pre-curtailment would be required to provide the service. At the same time, specifying a fixed requirement in a rapidly changing environment can be futile. **An outdated / inappropriate grid requirement may cause more harm than no requirement at all.**

2. **Ancillary services.** Grid operators are increasingly turning to ancillary services in order to bring flexibility into meeting network reliability needs. An ancillary service mechanism can enable economic remuneration and competitive procurement when defined by performance requirements that pay for performance vs meeting a fixed requirement. More importantly, a market mechanism can enable a more dynamic specification where, for example, **procurement levels can be defined with grid conditions** (e.g. varies with dispatch conditions).

Reliability measures and mechanisms identified during this analysis step will help further refine the "optimized system scenario."

Step 2 (c): Adequacy simulations to identify additional resource needs

As mentioned above, traditional approaches to resource adequacy focus on the peak load hour as the period of highest reliability risk. However, given the significant level of system transformation here, **non-peak hours will present new adequacy risks**. The hours of risk identified in Step 2(a) will be used for adequacy analysis in this step using tools like GE MARS[33] to determine additional needs required in the form of additional reserves, capabilities or resources.

Based on a full sequential Monte Carlo simulation, GE MARS performs a chronological hourly simulation of the system, comparing the hourly load in each area to the total available generation, which has been adjusted for uncertainty (e.g. randomly occurring forced outages). Areas with excess capacity will provide assistance to deficient areas, subject to transfer limits between the areas. Including the uncertainty of renewable and load resources into this probabilistic framework is essential for understanding the real adequacy risks.

Another important point to consider here is the use of appropriate reliability metrics. The traditional metrics of **Loss of Load Expectation (LOLE) which measures reliability in the form of number of load loss events per year may no longer be appropriate**. This metric does not give weighting to the duration or size of a loss of load event. Given the hourly variability in the system, metrics that capture the duration or size of reliability events may provide better insight into mitigations that most efficiently meet the need. In addition, since variability can impact adequacy in similar ways to outages, flexibility and performance capabilities increasingly matter. For example, short duration / size events could be

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[33] GE Multi-Area Reliability Simulation (https://www.geenergyconsulting.com/practice-area/software-products/mars)

addressed through demand-side measures while long duration / larger events may be best addressed with additional system capacity. Examples of other mitigation measures may include:

- Other (non-generation) sources of regulation and/or reserves: **Demand Side Management** (DSM), storage and other options that may be available
- **New generation resources**: new flexible combined cycle units, peakers, and other options that may be available
- **Sharing** regulation & reserves with neighboring utilities
- Improvements in renewable **forecasting** methods/accuracy
- Changes in how forecasting is used in the **unit commitment/scheduling** process
- **Energy storage** for regulating reserves and/or energy shifting

Adequacy measures identified during this analysis step will help further refine the "optimized system scenario."

Step 2 (d): Reflect constraints and incorporate mitigations into optimized system scenarios & repeat process

Once these new optimized scenarios are developed, we recommend feeding the cumulation of updates back into the above steps again in order to re-simulate the system. In this way, we are capturing the collective effect of any changes across all the timescales of operation: resource needs, production cost, network reliability and adequacy in order to converge upon new scenarios that are both economically and technically optimized.

10.3.3 Conclusion: Holistic planning is required for deep decarbonization

In this section, the GE Energy Consulting team has presented thoughts regarding how Canadian provinces can holistically plan for deep levels of decarbonization where the operations, economics, and physics of the system are all transforming at the same time. The traditional linear planning approach is no longer sufficient. A new iterative and integrated approach with **tighter coupling between the economic and technical simulation environments is needed** with results of each class of simulation impacting and advising changes in the other.

The traditional process for system planning often relies on a high level of entrenched institutional knowledge about the characteristics and limitations of the grid. Planning and operations experts have known where to look for problems and under what conditions they are likely to occur. In a radically altered future, with substantively different resource technologies, the institutional knowledge of the grid's vulnerabilities is reduced. **Planning now needs to look beyond risks during peak load intervals**. These intervals of risk need to be identified using hourly dispatch analysis and then studied using appropriate technical analysis methods to identify mitigations.

11 APPENDIX A: GRID CODE APPLICATION GUIDE FORM (EXAMPLE)

THE UTILITY FORUM OF NATURAL RESOURCES CANADA CANADIAN GRID CODES APPLICATION GUIDE (EXAMPLE)

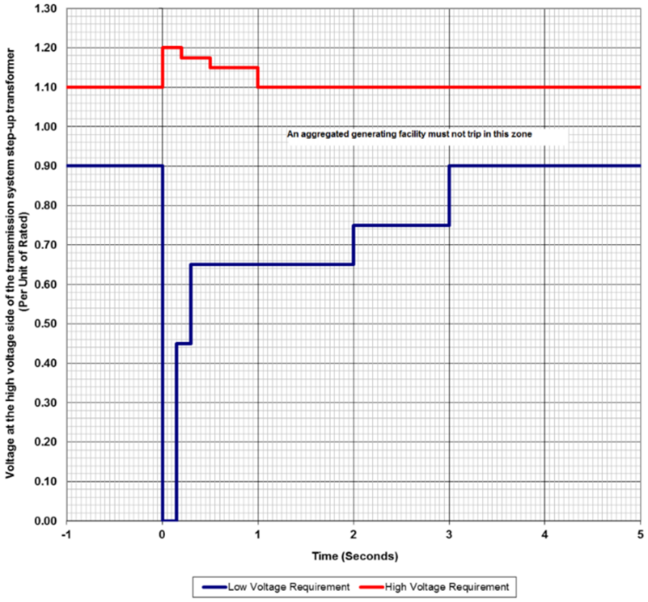
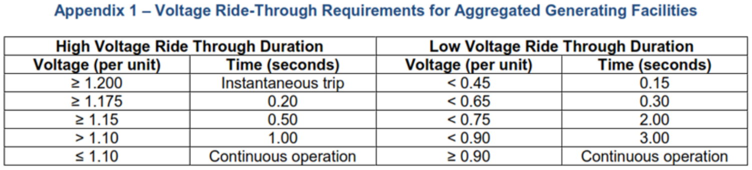
Provincial Grid Codes Summary Form

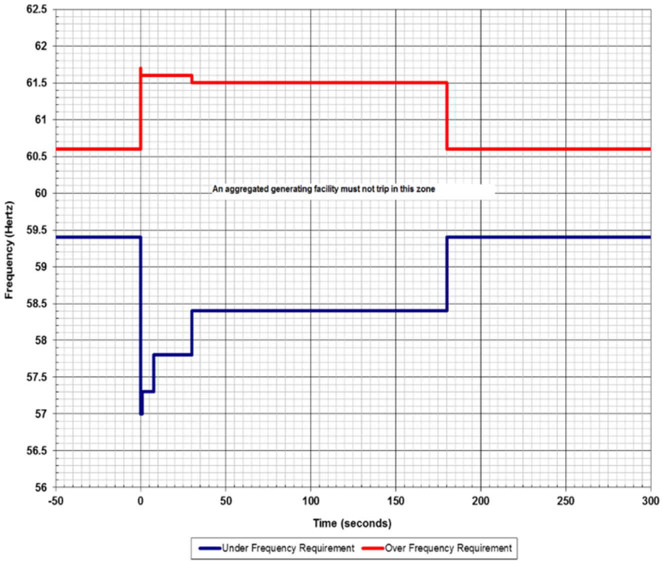
PART A: OPERATOR INFORMATION	
1. OPERATOR NAME	Alberta Electric System Operator
2. GRID CODE DOCUMENT DATE	September 2020
3. SUMMARY FORM DATE	18 May 2021

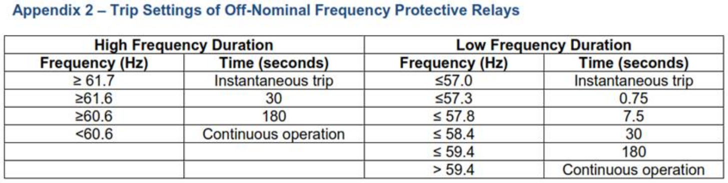
REQUIREMENT	**OPERATOR CODE**	**OPERATOR CODE REFERENCE**
PART B: VOLTAGE RIDE-THROUGH		
4. Continuous Range	0.9-1.1 Vpu @ POI	502.1 5
5. Connection Point	Transmission Xfmr HV side	
6. Blocking (cessation)	Not specified	
7. Max OV	1.2 Vpu	
8. Min UV	0V @ 150 msec	
PART C: VOLTAGE REGULATION		
9. Range	0.95-1.05 Vpu	502.1 6
10. Droop	0-10% adjustable	
11. Resolution	±0.5%	
12. Response Time	Wind: 1 sec, Sept'20: 0.1s <= response time <=1s	
PART D: REACTIVE POWER CAPABILITY		
13. PF/VAR Range	+0.90 to -0.95	502.1 4
14. Active Power Range	P ≥ Pmin	
15. Zero Active Power?	Not specified	
PART E: POWER QUALITY		
16. Flicker	Pst = 0.8, Plt = 0.6	502.1 14
17. Harmonics	IEEE 519	502.1 7 (3)
18. Unbalance	Not specified	
19. Max OF	61.7 Hz	
20. Min UF	57 Hz	
PART F: FREQUENCY RESPONSE		
21. Droop range	3-5%	502.1 7
22. Deadband	Max ±36 mHz	
23. Resolution	±0.004 Hz	
24. Response Time	Not specified	
25. Inertial Response	None	
PART G: Other		
26. Point of Interconnection	Difference between Ride-through and regulation point?	5.1 vs 6.2
27. Max Ramp Rate Control	1MW resolution, ramp ctrls req'd, ramp rate not to exceed in MW/min	304.3 3(2) & (5-7)

	range equal to 5-20% of gross real power capability, default setting must be 10%	
28. Stabilizer	Required for synchronous units, for asynchronous, if WECC requires, then ISO might require too	502.1 8
29. Protection	"Must have systems, controls, procedures to electrically disconnect as documented in the functional specification"	502.1 12
30. Data Reporting	Specifies met towers, 15 sec instantaneous measurements, submit 30 min gross power capability w/ 2MW resolution + list of data requirements (table 1)	304.9
31. Forecasting	no forecasting reqt	
32. Modeling	Must perform model validation testing	502.16 10
33. Momentary Cessation	Not specified	
34. Phase jump immunity including phase-locked loop ride-through.	Not specified	
35. Inverter current injection during faults	Not specified	
36. Return to Service Following Tripping	BES facility and aggregate facility near Medicine Hat require approval from ISO to reconnect.	502.14.5, 502.16.16
37. Balancing including ancillary services such as AGC (automatic generation control)	in order to qualify, asset must have either AGC capability (responsive w/in 28 sec of receiving signal, & 40 sec of signal reversal), or a governor system (defined by freq response reqts) & must satisfy ramp rate req'ts (10% of real power)	205.4
38. Monitoring and data reporting requirements such as data points and update intervals	Specifies met towers, 15 sec instantaneous measurements, submit 30 min gross power capability w/ 2MW resolution + list of data requirements (table 1)	304.9
39. Operation in low short-circuit ratio (weak) systems	Not specified	
40. Grid forming capability and performance	Not specified	
41. Anti-islanding protection and island mode operation	Must be designed with manually operable isolation switches	502.1 13
42. System restoration and black start	Defines SCADA req'ts for resources providing black start	502.8 Appendix 5
43. Where applicable, generation forecast requirements, measured meteorological data reporting	Specifies met towers, 15 sec instantaneous measurements, submit 30 min gross power	304.9

	capability w/ 2MW resolution + list of data requirements (table 1)	
44. Battery energy storage – behavior during under frequency load shedding	Table & curve with frequency ranges (same as REN)	502.13 Appendix 3
45. Power system damping and small signal stability	Only mentioned briefly with power system stabilizer	502.1 9(3)
46. Sub-synchronous resonance (SSR) and sub-synchronous control interaction (SSCI)	Must not introduce any resonance including self-excitation of induction machines, transformer ferroresonance, resonant effects of capacitor additions and the capacitance of the cables	502.1 14 (1c)
47. Control stability, control interactions and weak grid connection	Vague allusion to stability "concerns"	502.1 4(5)

<table>
<tr><th colspan="3">PART H: CHARACTERISTIC CURVES</th></tr>
<tr><th>REQUIREMENT</th><th>CURVE</th><th>OPERATOR CODE REFERENCE</th></tr>
<tr><td>48. Voltage ride-through curve</td><td>
</td><td>502.1 Appendix 1</td></tr>
<tr><td>49. Voltage ride-through settings</td><td>
Appendix 1 – Voltage Ride-Through Requirements for Aggregated Generating Facilities
<table>
<tr><th colspan="2">High Voltage Ride Through Duration</th><th colspan="2">Low Voltage Ride Through Duration</th></tr>
<tr><th>Voltage (per unit)</th><th>Time (seconds)</th><th>Voltage (per unit)</th><th>Time (seconds)</th></tr>
<tr><td>≥ 1.200</td><td>Instantaneous trip</td><td>< 0.45</td><td>0.15</td></tr>
<tr><td>≥ 1.175</td><td>0.20</td><td>< 0.65</td><td>0.30</td></tr>
<tr><td>≥ 1.15</td><td>0.50</td><td>< 0.75</td><td>2.00</td></tr>
<tr><td>> 1.10</td><td>1.00</td><td>< 0.90</td><td>3.00</td></tr>
<tr><td>≤ 1.10</td><td>Continuous operation</td><td>≥ 0.90</td><td>Continuous operation</td></tr>
</table></td><td>Appendix 1</td></tr>
</table>

<table>
<tr>
<td>50. Frequency ride-through</td>
<td>


</td>
<td>Appendix 2</td>
</tr>
<tr>
<td>51. Frequency protective relay trip settings</td>
<td>

Appendix 2 – Trip Settings of Off-Nominal Frequency Protective Relays
<table>
<tr><th colspan="2">High Frequency Duration</th><th colspan="2">Low Frequency Duration</th></tr>
<tr><th>Frequency (Hz)</th><th>Time (seconds)</th><th>Frequency (Hz)</th><th>Time (seconds)</th></tr>
<tr><td>≥ 61.7</td><td>Instantaneous trip</td><td>≤57.0</td><td>Instantaneous trip</td></tr>
<tr><td>≥61.6</td><td>30</td><td>≤57.3</td><td>0.75</td></tr>
<tr><td>≥60.6</td><td>180</td><td>≤ 57.8</td><td>7.5</td></tr>
<tr><td><60.6</td><td>Continuous operation</td><td>≤ 58.4</td><td>30</td></tr>
<tr><td></td><td></td><td>≤ 59.4</td><td>180</td></tr>
<tr><td></td><td></td><td>> 59.4</td><td>Continuous operation</td></tr>
</table>
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<td>Appendix 2</td>
</tr>
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