DGA Consulting

INTERNATIONAL REVIEW OF FREQUENCY CONTROL ADAPTATION

Australian Energy Market Operator

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Report Preparation Process
This report was prepared in a collaborative process between DGA Consulting and AEMO. AEMO guided the areas of focus of the report, directing analysis towards topics of most interest and relevance to the Australian National Electricity Market (NEM). The analysis conducted by DGA Consulting in those areas of focus was augmented with additional inputs from AEMO, including the contribution of additional NEM-specific context, the contribution of references and insights from a number of additional markets, and the suggestion of some additional relevant insights for the NEM from the jurisdictions explored.

Contents

Figures

Tables

ACRONYMS

AC	Alternating Current
AEMO	Australian Energy Market Operator
AGC	Automatic Generation Control
AUFLS	Automatic Under Frequency Load Shedding
CAISO	California Independent System Operator
CCGT	Combined Cycle Gas Turbine
CER	Commission for Energy Regulation (Ireland)
CPUC	California Public Utilities Commission
CRS	Contingency Reserve Service (ERCOT, Texas)
CUSC	Connection and Use of System Code (Great Britain)
DC	Direct Current
DFIG	Double-fed induction generator (wind turbine)
DSM	Demand Side Management
DSO	Distribution System Operator
EFCC	Enhanced Frequency Control Capability (Great Britain)
EFR	Enhanced Frequency Response (Great Britain)
ENTSO-E	European Network of Transmission System Operators
EPRI	Electric Power Research Institute
ERCOT	Electricity Reliability Council of Texas
EU	European Union
FERC	Federal Energy Regulatory Commission
FFR	Fast Frequency Response
FFRS	Fast Responding Regulation Service (ERCOT, Texas)
FFTA	Fast Fourier Transform Analysis
FIR	Fast Instantaneous Reserves (New Zealand)
FPFAPR	Fast Post-Fault Active Power Recovery (Ireland)
GB	Great Britain
GT	Gas Turbine
HVDC	High Voltage Direct Current
IESO	Independent Electricity System Operator (of Ontario, USA)
ISO	Independent System Operator
LBO	Lean blow-out (of a gas turbine)
LFSM-O	Limited Frequency Sensitive Mode – Overfrequency (Great Britain)
MISO	Mid-continent Independent System Operator
NEM	National Electricity Market

NPRR	Nodal Protocol Revision Request (ERCOT, Texas)
NREL	National Renewable Energy Laboratory (of the USA)
OCGT	Open Cycle Gas Turbine
OEM	Original Equipment Manufacturer
ONS	Operador Nacional do Sistema Elétrico (System Operator of Brazil)
PFR	Primary Frequency Response
PRS	Protocol Revision Subcommittee (ERCOT, Texas)
PV	PV
RoCoF	Rate of Change of Frequency
RPP	Renewable Power Plant (South Africa)
RTO	Regional Transmission Organization
SA	South Australia
SEM	Single Electricity Market (Ireland)
SIR	Synchronous Inertial Response
SIRF	Synchronous Inertial Response Factor (Ireland)
SNSP	System Non-Synchronous Penetration (Ireland)
SOF	System Operability Framework (of Great Britain)
SONI	System Operator of Northern Ireland
TAC	Technical Advisory Committee (ERCOT, Texas)
TSO	Transmission System Operator
UFLS	Under Frequency Load Shedding
UK	United Kingdom
UR	Utility Regulator (of Northern Ireland)
WPP	Wind Power Plant
WSAT	Wind Security Assessment Tool (Ireland)
WTG	Wind Turbine Generator

EXECUTIVE SUMMARY

Power systems around the world are experiencing a rapid growth in wind and photovoltaic (PV) technologies, which are different from conventional technologies in a number of important ways that influence frequency control. This report explores international experiences adapting frequency control measures, aiming to draw out key insights for the Australian National Electricity Market (NEM).

Experiences with high RoCoF

Coal and gas-fired generation are "synchronous" technologies, which contribute inertia to the power system. Inertia acts to slow the Rate of Change of Frequency (RoCoF) following a contingency event (the unexpected loss of generation or load). In contrast, wind and PV are "non-synchronous", and do not contribute inertia. Growth of wind and PV increasingly displaces generation by synchronous technologies, which lowers the inertia of the power system. This means that the RoCoF following a contingency event can become very high, challenging frequency management and physically stressing synchronous generators.

Although the NEM features relatively moderate wind and PV penetration levels in most states, wind and PV development has a much higher penetration level in the South Australia (SA) region. When wind and PV are operating at high levels in SA, this displaces the generation of synchronous units, such that there may be little synchronous inertia in the state, and higher RoCoF levels become possible. As further wind and PV generation is added across the NEM, high RoCoF levels may eventually become problematic system wide.

This review found very few large international jurisdictions (500 MW or more) that are experiencing issues related to high RoCoF. Large, highly interconnected systems (such as Germany, Denmark, the Eastern and Western Interconnections in the USA, and Texas) are unlikely to encounter issues related to high RoCoF until they reach renewable penetration levels far beyond those now being studied. These large systems experience RoCoF levels well below 0.5 Hz/s.

EirGrid/SONI (Ireland/Northern Ireland), and National Grid (Great Britain) are notable exceptions; both have identified emerging concerns about high RoCoF levels (>0.5 Hz/s), and have established work programs to address the specific challenges facing their systems. Since there are very few international jurisdictions now encountering high RoCoF challenges, these work programs are breaking new ground.

EirGrid/SONI have undertaken a multi-year program of generator testing, to establish the RoCoF withstand capabilities of each unit. The testing involves considerable cost, and long timeframes. The program of work was carefully prioritized, recognizing the limited pool of specialist expertise required from manufacturers. A similar process may be required in the NEM.

Because EirGrid/SONI are more advanced in their work than any other jurisdiction, collaborating with them to share experience and results could significantly benefit both parties.

A number of other international jurisdictions have implemented RoCoF standards for generators. For example, Denmark has a RoCoF standard of 2.5 Hz/s, and Spain has a RoCoF standard of 2 Hz/s. These access standards do not appear to have inhibited new generation development. This suggests that it may be possible to increase the present NEM minimum access standard for RoCoF to ensure that the future power system has higher RoCoF withstand capabilities.

Studies from EirGrid indicate that generator RoCoF withstand capabilities depend strongly on the duration of time they are exposed. In the NEM, the minimum access standard (which all new entrants must meet as a minimum) is 1 Hz/s for 1 second, and the automatic standard (which is "automatically" accepted without negotiation to be adequate for new entrant connections) is 4 Hz/s for 250ms (a higher RoCoF level, but for a shorter duration). EirGrid's analysis suggests that a generator may meet the automatic standard, but *not* meet the minimum standard. This means that it may be prudent to explicitly require generators meeting the automatic standard to also meet the minimum standard.

Fast Frequency Response to Mitigate High RoCoF

A Fast Frequency Response (FFR) is defined as a rapid active power injection (in 1-2 seconds or less), to arrest the frequency decline following a contingency event. It is often termed "synthetic" or "emulated" inertia. FFR can be an important tool in mitigating high RoCoF, by very rapidly correcting the supply-demand imbalance following a contingency event.

Modeling from EirGrid indicates that FFR can be an effective tool to reduce the amount of synchronous inertia required to maintain power system frequency, if the FFR control systems are appropriately designed. The degree to which FFR can displace synchronous inertia depends strongly upon the precise characteristics of the FFR. Modeling is required to establish the potential benefits of such a service in the NEM. However, EirGrid's analysis emphasizes that considerable technical challenges remain for the robust delivery of an FFR service, particularly around measuring and identifying high RoCoF events.

The international literature is clear that FFR alone is not sufficient; it is not now possible to operate a large power system without any synchronous inertia, and synthetic/emulated inertia does not provide a direct replacement. This means that an effective measure may be required in the NEM to ensure enough synchronous inertia is provided in the future.

In future, it may become possible to manage a power system without any synchronous inertia, using inverter-connected devices to set and maintain frequency. This service would be different from FFR, because it would involve constantly and "instantaneously" maintaining frequency (rather than just responding following a contingency event). International research is progressing in this field. This suggests that any inertia procurement mechanism introduced in the NEM should be designed to transition over time as new technology options emerge.

Storage technologies for frequency control

Storage technologies are capable of very rapid frequency responses, including an FFR-type response. For example, storage technologies are becoming the dominant technology delivering fast regulation services in the PJM Interconnection market in the USA, and were the primary technology selected in the UK tender process for fast frequency services (delivered via a droop response). However, this fast response capability is not standard for energy storage technologies, and analysis from the UK suggests it is expensive to retrofit. This suggests it may be beneficial for AEMO to encourage inclusion of fast response capabilities in the initial design of emerging energy storage projects.

Manufacturers are actively designing new products targeted at managing high RoCoF, recognizing the potential growing opportunity. New technology solutions are likely to emerge, so any new service specification (such as FFR) would ideally be introduced with a technology-neutral approach.

Demand response for fast frequency control

PJM found that a 1 MW minimum size requirement for demand-side aggregators was a significant barrier to demand-side participation in frequency control. Once this level was reduced to 0.1 MW, demand participation increased considerably. The NEM similarly has a 1 MW minimum size requirement for participation in frequency control markets. PJM's experience suggests that reducing this size requirement may facilitate increased demand-side participation.

Emulated inertia from wind turbines

Emulated/synthetic inertia from wind turbines could provide an important low-cost source of FFR in future. This service draws upon the physical inertia stored in the wind turbine's rotating blades to provide a brief active power injection when a contingency event is detected. Hydro-Québec, in Canada, has mandated delivery of this service since 2006, and Brazil and Ontario are now also requiring this capability.

The nature of the emulated/synthetic inertial response from wind turbines can be tailored to specific needs (within physical limitations). Wind turbines with this capability at present have largely been designed to meet Hydro-Québec's specifications. However, different response characteristics could be requested in the NEM. Simulations would be required to determine the optimal response characteristics for the NEM.

The emulated/synthetic inertial response from wind turbines features a "recovery period", following the initial active power injection. In the recovery period, active power production is reduced temporarily, while the turbine blades reaccelerate. Analysis in some jurisdictions has suggested that the recovery period can create complications during frequency recovery, and should be carefully modelled to ensure this can be managed.

The design of new frequency control ancillary services

A number of jurisdictions have considered modifying frequency control ancillary services (FCAS) to accommodate increasing amounts of wind and PV generation. For example, ERCOT invested several years developing a new framework (including introducing FFR-type services, and a synchronous inertia service); this was ultimately rejected because stakeholders believed it was not necessary. EirGrid/SONI (in Ireland/Northern Ireland) are introducing a comprehensive new FCAS framework, with new services including an FFR-type service (with a two second response time), and a synchronous inertia service. They have also introduced an explicit service for faster post-fault active power recovery. AEMO may find value in collaborating with EirGrid/SONI on the development and implementation of these new services.

Several markets in the USA (MISO and CAISO) have introduced new ramping services, to manage large ramps over periods longer than a dispatch interval, and ensure there are adequate and effective price signals for incentivizing flexibility. It is unclear whether the NEM may need something similar to manage increasing variability from wind and PV generation; the day-ahead markets in MISO and CAISO may be an important point of difference.

Other aspects of frequency control

International experience shows that the variability of wind and PV varies depending upon the level of operation of wind and PV generation. This may provide an opportunity to develop and implement control center tools to anticipate system variability and the resulting regulation needs.

International studies and experience suggest that wind and PV generators can effectively and efficiently provide a wide range of frequency control services. It may be prudent to encourage new entrants to include these capabilities, to ensure the services are available when required in future.

EXTENDED REPORT SUMMARY

This report explores international experience adapting frequency control measures, aiming to understand their experiences, and draw out key insights for the Australian National Electricity Market (NEM).

Power systems around the world are experiencing a rapid growth in wind and PV technologies, which are different from conventional technologies in two important ways that influence frequency control. Wind and PV are:

- **Non-Synchronous**—Many conventional power generation technologies (such as coal and gas) are "synchronous", which means that they contribute inertia to the power system. Inertia acts to limit the Rate of Change of Frequency (RoCoF) following a contingency event (an unexpected loss of generation or load). In contrast, wind and PV are "non-synchronous" technologies, and do not contribute inertia to the power system. As wind and PV displace coal and gas, this reduces the power system inertia, and increases the RoCoF when a contingency event occurs. This means that frequency control measures must act more quickly to arrest the frequency change and maintain frequency within required limits [1]. This effect is significant for managing frequency control over periods of seconds and less.
- **Variable and uncertain**—Wind and PV have variable and somewhat uncertain generation patterns. This means that power systems with a large proportion of wind and PV will need to manage more variability and uncertainty, including larger and more frequent minor imbalances in supply and demand. These imbalances are typically managed through regulation frequency control measures [1]. This effect is significant for managing frequency control over periods of minutes and hours.

These two factors means that most of the international experience in frequency control adaptation (as summarized in this review) revolves around these two key areas: 1) Managing power systems with low inertia (and therefore high RoCoF), including the potential use of emerging technologies for faster frequency control, and, 2) Managing increasing variability and uncertainty.

Experiences with high RoCoF

This review found very few large international jurisdictions (500 MW or more) that are experiencing issues related to high RoCoF. EirGrid/SONI (Ireland/Northern Ireland), and

National Grid (Great Britain) are notable exceptions; both have identified emerging concerns about high RoCoF levels (>0.5 Hz/s), and have established work programs to address the specific challenges facing their systems. These work programs are especially relevant to the NEM, and some specific findings from an examination of these work programs are outlined below.

Smaller island grids (such as Cyprus and Hawaii) have also experienced high RoCoF events. However, these systems are less relevant to the NEM for a number of reasons. Firstly, as very small systems they do not have significant markets, and therefore do not offer insights on market implementation. Secondly, although there may be lessons from the demonstration of a range of technical solutions in these systems, scaling these up to the scale of the NEM may not be commercially optimal. For example, Hawaii makes extensive use of batteries for managing wind and photovoltaic variability, but a similar approach may not be optimal at the scale of the NEM due to the cost involved in scaling up the battery systems, and the availability of a broader range of technical options in a larger system.

Large, highly interconnected systems (such as Germany, Denmark, the Eastern and Western Interconnections in the USA, and Texas) have orders of magnitude more synchronous inertia than these examples, and are therefore unlikely to encounter issues related to RoCoF until they reach *significantly* higher renewable penetration levels (far beyond the levels being studied at present). For example, a study of the Western Interconnection in the USA with a 33% wind and solar scenario simulated a RoCoF of 0.118 Hz/s in the most extreme sensitivity explored [2]. The low RoCoF value calculated is due to the very large scale of the Western Interconnection, and the comparatively smaller size of the contingency event modelled (a trip of two fully loaded nuclear power station units for a loss of 2,750 MW, representing around 2% of the system size). Similarly, ERCOT (Texas) has experienced a maximum RoCoF of 0.2 Hz/s, and projects that 0.4 Hz/s may be possible in future [3]. These levels of RoCoF remain an order of magnitude below those now possible in South Australia [1].

The specific findings of this review relating to international experiences with high RoCoF are outlined below.

Insights for the NEM

RoCoF Access Standards

There may be justification for initiating a review of the NEM Access Standards relating to RoCoF. The present Access Standards for RoCoF in the NEM are summarized in Table 1.

Table 1 - RoCoF access standards in the NEM [4]

	Requirement defined in the NER
Minimum Access Standard	±1 Hz/s for 1 second
Automatic Access Standard	±4 Hz/s for 250 ms

Firstly, modelling conducted by DNV-GL (for EirGrid/SONI) suggests that the RoCoF withstand capabilities of synchronous generators are highly dependent upon the duration of time that they are exposed. For example, a 260 MW CCGT dual-shaft machine was found to remain stable under RoCoF of -2.2 Hz/s for 250 ms (under the operation conditions of 100% load and a power factor of 1 unity), but was not stable at -1 Hz/s for 1 second [5]. This suggests that the NEM Automatic Access Standard (4 Hz/s for 250 ms) could actually be *less* onerous than the Minimum Access Standard (1 Hz/s for 1 second) in some cases. This may mean that a generator could be allowed to connect based upon the Automatic Access Standard, but not be able to meet the Minimum Access Standard. This could be investigated with modelling, and possibly unit testing. It may be prudent to change the Automatic Access Standard so that it specifies a need to also withstand 1 Hz/s for 1 second.

Secondly, EirGrid/SONI's experience highlights that the subtleties in how the measurement window is defined have consequences for withstand capabilities. They have selected a measurement window of 500 ms, measured as a rolling window. However, DNV-GL's modelling found that the RoCoF withstand capabilities of synchronous generators are highly sensitive to the total duration of the RoCoF event. Their modelling showed that most generators could achieve compliance with a 1 Hz/s standard over an *absolute time window of 500 ms*. However, the capabilities of generators were much lower when the 1 Hz/s RoCoF was sustained over a full second (for a 1 Hz absolute drop) [5]. This means that meeting the 500 ms rolling window standard could pose challenges for synchronous generators in the EirGrid system, even where DNV-GL's modelling indicated that the units were stable at 1 Hz/s for 500 ms [6]. For the purposes of generator testing, EirGrid has defined representative frequency traces that should be withstood; this may offer a suitable approach.

It may also be prudent to explore the potential for implementing a more stringent Minimum Access Standard. EirGrid/SONI have faced considerable challenges in attempting to increase their system-wide RoCoF standard from 0.5 Hz/s to 1 Hz/s (over a 500 ms rolling window). Demonstrating compliance with a stringent standard is far more straightforward for new connections, when the original equipment manufacturer (OEM) is already heavily involved. EirGrid/SONI have discovered that the process of demonstrating RoCoF compliance for incumbents is far more complicated and costly.

It is clear that the NEM power system is trending towards lower levels of synchronous inertia, meaning that there are significant advantages in targeting a future power system with higher RoCoF withstand capabilities. This process needs to commence early, to ensure that generation installed now (which is likely to remain operating in 10-30 years) has demonstrated the capabilities to confidently operate in the future high-RoCoF regime.

This suggests that the minimum access standards for RoCoF should be set at the highest possible level that does not constitute a barrier to entry, and does not substantially increase costs for new entrants. Other jurisdictions (such as Denmark) have access standards as high as 2.5 Hz/s (over 200 ms), suggesting that standards around this level may be achievable, and may not present a significant barrier to entry. RoCoF standards applying in other jurisdictions are summarized in Table 2.

Table 2 – RoCoF Standards applied in other jurisdictions

	RoCoF Standard
Ireland (EirGrid/SONI)	0.5 Hz/s, changing to 1 Hz/s (over a 500ms rolling window)
Great Britain (National Grid)	0.125 Hz/s, changed recently to 0.5 Hz/s for incumbent synchronous units, and 1 Hz/s for non-synchronous units and new synchronous units (over 500 ms)
Denmark	2.5 Hz/s (over 200 ms for wind & PV, no specified timeframe for synchronous)
New Zealand	Does not have a standard for RoCoF
Hawaii	Does not have a standard for RoCoF
Spain	2 Hz/s [7, 8]
South Africa	1.5 Hz/s (applying only to renewable power plants) [8, 9]

Determining the RoCoF capabilities for the range of potential new entrants requires careful consideration. This is particularly pertinent for gas-fired generation, which this review indicates could be more sensitive to RoCoF than inverter-connected generation, and which could be an important new entrant in the NEM (particularly for peaking capacity). The likely RoCoF capabilities of other types of synchronous generators should also be considered carefully, including solar thermal, biomass and geothermal. This process will need to involve manufacturers; AEMO could consider initiating a work package to interview manufacturers, and determine the maximum RoCoF levels for which they are prepared to endorse their products.

EirGrid/SONI's high-level analysis shows signs of instability (and potential for pole slipping) for incumbent synchronous units at around 1 - 1.5 Hz/s. This modeling is not conclusive, however, and it may be possible to design new units with higher RoCoF withstand capabilities. Analysis of historical international high RoCoF events suggests there is no evidence of significant mechanical damage for synchronous units due to high levels of RoCoF. And, there is no evidence of generators tripping directly due to high levels of RoCoF [10]. In some cases units have been observed to trip due to various control and instrumentation issues [10]. In these cases it was possible to address the identified issues by adjusting the relevant control and protection systems. However, the availability of data from historical events is limited, and is insufficient to draw strong conclusions.

Generator testing for RoCoF withstand capabilities

EirGrid/SONI's experience shows the significant amount of time involved in testing of generators to determine RoCoF withstand capabilities. The individual unit testing required is complex, non-routine, and requires engagement of specialist expertise at the relevant OEMs.

Given the uncertainty over the RoCoF withstand capabilities of most generators in the NEM, the trends towards higher RoCoF exposure, and the likely expense involved in mitigating high RoCoF exposure, it would be beneficial to rigorously establish the RoCoF withstand capabilities of generators in the NEM. EirGrid/SONI's high-level analysis indicates signs of instability (and potential for pole slipping) for synchronous units at around 1 - 1.5 Hz/s. This is within the RoCoF exposure levels in South Australia at present [1].

For these reasons, the NEM could consider commencing a program of work to establish the RoCoF withstand capabilities of individual units. Given resource constraints and the very limited number of specialists with the required expertise at OEMs, this should be carefully planned, probably targeting the highest capacity factor units in SA first.

EirGrid's program of work focuses on each unit demonstrating the ability to comply with their proposed 1 Hz/s standard. EirGrid's analysis suggests that testing will need to consider a wide range of aspects for each generating plant, including:

- ***Mechanical integrity*** – transient torques on machine shafts and turbine blades, including the potential for pole slipping in synchronous units,
- ***Protection*** – The potential for misoperation of plant protection systems under conditions of extreme RoCoF,

- ***Control Systems*** – The potential for unintended consequences related to plant control systems, under conditions of extreme RoCoF,
- ***Unit specific factors*** - Flame stability or over-temperature in gas turbines (GT)s, and hydraulic transients in hydro plant, and
- ***Auxiliaries*** – Impact on auxiliary plant such as motors (e.g. boiler feed pumps, gas compressors).

The studies required to robustly demonstrate RoCoF withstand capabilities are likely to be costly; GE estimated the associated costs of testing to be around US $1.5 M per CCGT [11, 8], while another source estimated similar costs at around of €900 k per plant [8]. Careful consideration will need to be given as to who will be responsible for paying these costs, and how they will be recovered. In Ireland, generators have been responsible for bearing the costs of demonstrating compliance with the proposed new standard, without the ability to recover these costs.

Anti-islanding protection for embedded generation

In some jurisdictions (such as Ireland and Great Britain), anti-islanding protection is based upon the detection of RoCoF, and can therefore trigger during extreme RoCoF events (when it is not desired). Even where anti-islanding protection is not based upon RoCoF directly, other types of protection may misoperate under conditions of extreme RoCoF. Given the increasing prevalence of distributed PV (and the large potential contingency size that could result from their tripping), it will be important to establish the level of RoCoF that can be tolerated by anti-islanding protection in the distribution network in the relevant parts of the NEM. Both Ireland and Great Britain have been conducting an extensive program of work to adjust anti-islanding protection settings, to withstand a higher level of RoCoF.

Collaboration with EirGrid/SONI on high RoCoF issues

EirGrid/SONI are the most advanced internationally on exploring RoCoF related issues. Their comprehensive work program (since 2010) provides many valuable insights for the NEM. Their ongoing work in this area should continue to be highly relevant and valuable. AEMO could explore the potential for a collaborative relationship with EirGrid/SONI, to share lessons learned and combine efforts in this challenging and groundbreaking field.

Fast Frequency Response to Mitigate High RoCoF

Terminology varies, but for this purposes of this report, a "Fast Frequency Response" (FFR) is defined as an active power injection, delivered within the first 1-2 seconds of a disturbance, to assist in arresting the frequency decline. In a low inertia (high RoCoF) power system, FFR is a potentially important service for mitigating high RoCoF, giving the governors of conventional generators (and other slower acting frequency control mechanisms) time to act to arrest, stabilize and restore system frequency.

Findings from this review on FFR are outlined below.

Insights for the NEM

Procurement mechanisms for synchronous inertia

International studies are clear that FFR is technologically and physically distinct from synchronous inertia. These should be considered as two different services, with different technical characteristics that interact differently with the power system.

At present, there are no examples of large power systems (hundreds of megawatts) operating with no synchronous generation. Modelling and analysis to date shows that FFR alone is not sufficient to maintain frequency, and is not a direct substitute for synchronous inertia. However, research in this field is active and growing, and may soon lead to sophisticated control systems that allow inverter-connected devices to set and maintain frequency, enabling genuine replacement of synchronous generation in large power systems. This would be a distinct service from FFR; it would continuously and actively set and maintain frequency (rather than being triggered by a RoCoF or frequency event), and therefore would not have the same challenges around measurement and identification of high RoCoF events as an FFR-type service.

This suggests that a procurement mechanism for synchronous inertia may be required in the NEM, to ensure that a minimum level of synchronous inertia is maintained for system security. This mechanism should ideally be designed such that it can transition over the longer term towards alternative inverter-connected solutions, as they are developed and demonstrated.

Fast Frequency Response service

International investigations have found that there are a range of technologies available to provide FFR-type services to assist in mitigating high RoCoF events, including batteries, flywheels, emulated/synthetic inertial responses from wind generation, and so on.

EirGrid/SONI's modelling suggests that an FFR-type service from inverter-connected devices could reduce the amount of synchronous inertia required to maintain system frequency. The precise relationship between the amounts required, however, will depend upon the specific characteristics of the FFR service. This suggests that exploring an FFR service in the NEM could be an important initiative to minimize the costs of mitigating high RoCoF. This would include quantifying the potential benefits of such a service in the NEM, and determining the parameters for its specification.

Managing stakeholder expectations

There is much excitement globally about the potential for emerging technologies to provide FFR-type services to mitigate high RoCoF. While these technologies show great promise in the long term, they are fledgling for this purpose at present, and there remain many challenges. In particular, analysis in Ireland and Great Britain has highlighted that robust and reliable measurement and identification of high RoCoF events poses a significant challenge, particularly over very short timeframes. Preliminary modeling suggests that the control mechanisms for the response of these devices is particularly important, and is at an early stage of development. International studies indicate that further research is required in this area before an FFR-type service could be implemented with confidence.

Storage technologies for frequency control

Batteries have been deployed at significant scale in various other markets, including various applications in frequency control. For example, in PJM, batteries and flywheels are now the dominant technology entering the market to provide dynamic (fast) regulation , with almost 250 MW installed (mostly lithium-ion batteries). Hawaii also has a range of battery projects in operation, assisting with ramp rate control at wind and solar generators. Korea Electric Power Corporation, the national utility of South Korea, is currently deploying the largest utility-based, battery energy storage system in the world. The system, when fully deployed in 2017, will total 500 MW.

However, this review did not encounter *any* examples of storage technologies being currently used in practice in other systems to provide an FFR-type service (defined as an active power response in 1-2 seconds or less, following a contingency event, to assist in managing high RoCoF). This is relatively unchartered territory.

Further findings from this review on FFR are outlined below.

Insights for the NEM

Technology neutral approach

Inverter-connected technology for managing high RoCoF is in a fledgling state at present, but is evolving rapidly. For example, Siemens is developing a product that acts as a STATCOM with power intensive supercapacitors to provide “artificial inertia” for frequency and voltage support [12]. Other manufacturers are likely to be exploring a range of other potential options. Such technologies show potential to be highly responsive and cost effective. This suggests that the specification of any new service (such as an FFR-type service) should be as technology-neutral as possible, focusing on power system needs rather than technology capabilities, and allowing flexibility for developing sophisticated new technologies.

Encouraging fast response characteristics

Storage technologies are capable of very fast response times, but this capability must be designed into the system when it is initially developed. Standard battery projects (designed for other purposes) may not be capable of delivery an FFR-type service, unless this is specifically included in the specifications of the project. For example, National Grid's review of existing battery installations found that very few would be capable of delivering fast frequency services without costly retrofitting [13].

It appears likely that FFR capability will be desirable in future, so battery projects now under development should be designed with this in mind. AEMO could consider engaging with organizations that promote and support such projects (such as project developers and the Australian Renewable Energy Agency) to encourage the inclusion of rapid frequency response capabilities.

Demand response for fast frequency control

Demand response has been demonstrated internationally to have the potential to provide various kinds of rapid frequency control. For example, demand response provides regulation services in PJM, and New Zealand has a 1 second contingency service specifically provided by demand response. Demand response could provide an important and cost effective source of FFR-type services in the NEM, if the service is specified appropriately and barriers are removed.

Insights for the NEM

Minimum size for demand-side aggregators

A 1 MW minimum size for demand aggregation was a significant barrier to demand-side participation in frequency control markets in PJM. Reducing this minimum size to 0.1 MW appeared to eliminate this barrier, and demand-side providers are now active in PJM's frequency control markets.

The NEM also has a 1 MW minimum size requirement for registration to provide frequency control services. Based upon PJM's experience, this may be a barrier to demand-side participation, and may warrant further investigation around the costs and benefits of alleviating this issue.

Emulated Inertia from wind turbines

An emulated/synthetic inertial response from wind turbines is a relatively new technology. This technology uses the kinetic energy in the spinning blades to provide a brief active power "boost" when a frequency disturbance is detected. This is a type of FFR service, and is technically distinct from a synchronous inertial response.

Only a few power systems currently require emulated/synthetic inertial capabilities from wind turbines; this review found mandatory requirements in Hydro-Québec, Ontario and Brazil. Of these, only Hydro-Québec appears to have any significant practical experience with the delivery of this service from wind turbines.

In Hydro-Québec, wind turbines have been shown to successfully provide an emulated inertial response as specified, in response to real contingency events. They show a response within 1-2 seconds, with an active power increase of 6-10% of rated capacity, which extends for about 10 seconds. Wind turbines of various types (from a number of different manufacturers) have been shown to successfully delivery this response.

The initial active power "boost" is followed by a "recovery period", where the wind turbines experience a reduction in active power, to reaccelerate the turbine blades and prevent stalling. During the recovery period, the active power from the wind turbine can be as much as 30% below the pre-contingency level, and can extend for a duration as long as 40 seconds.

The nature of the active power response and the characteristics of the recovery period depend strongly upon the prevailing wind speed at the time of the event. This creates complexities for the power system operator in anticipating the response that will be delivered following a contingency event.

Insights for the NEM

Simulations for the NEM

The emulated/synthetic inertial response from wind turbines is very flexible, within physical limitations. There is potential to request that manufacturers produce the specific capabilities from wind turbines that would be most beneficial to the NEM. Detailed dynamic frequency simulations would be required to determine the optimal response characteristics, to suit the NEM. The typical response characteristics of wind turbines now on the market were mostly designed to suit the Hydro-Québec system, and could provide a suitable starting point for these investigations, but should not be assumed to be the only possible response.

In any modelling, particular care should be taken to represent the recovery period, and ensure that the primary frequency response (governor response) of other units can compensate for this active power reduction. If this is done poorly, the emulated/synthetic inertial response may successfully arrest the initial frequency decline, but lead to cascading system collapse during the recovery period. In general, a larger initial active power injection for a longer duration will require a longer and deeper recovery period (to recover the required energy).

Emulated/synthetic inertial capabilities

An emulated/synthetic inertial response from wind turbines (a type of FFR) could prove to be an important and cost-effective component for managing high RoCoF in the future. Wind turbines installed today are expected to remain in operation for 10-30 years, and retrofitting, calibrating and verifying this capability later could be considerably more expensive than including it during the initial design and commissioning (when the OEM is already engaged in the testing and verification process). This suggests that it could be prudent to encourage the inclusion of an emulated/synthetic inertial response capability in new entrant wind farms, particularly in South Australia. Wind farms could include the *capability*, but not necessarily deliver the response, at this stage. This would ensure they are available to deliver this service when it is required in future.

A mandatory requirement for emulated/synthetic inertial capabilities has been introduced in Hydro-Québec and Ontario, and has not halted investment in new wind generation, suggesting that it does not pose an insurmountable barrier to entry.

The design of new frequency control ancillary services

A number of jurisdictions have invested considerable time and effort in developing new ancillary services frameworks, in response to growing penetrations of non-synchronous, variable generation. A common theme across these new frameworks is the introduction of some kind of FFR or fast frequency control, as summarized in Table 3.

Table 3 - Fast Frequency Ancillary Services introduced or considered internationally

	Service type	Response time	Sustain duration	Notes
Ireland (EirGrid/SONI)	FFR – contingency service, triggered by local frequency	2 seconds	8 seconds	To be implemented October 2016
Texas (ERCOT)	FFR - contingency service, triggered by local frequency	0.5 seconds	10 minutes	All proposed changes rejected (May 2016)
Great Britain (National Grid)	EFR – Continuous frequency regulation via droop response to local frequency	1 second	15 minutes	Procured via tender process (Aug 2016), to be installed by 1 Mar 2018,

EirGrid/SONI and ERCOT's proposed frameworks also include introducing a Synchronous Inertial Response (SIR) service, providing a precedent for potentially introducing something similar in the NEM.

As of the time of writing this report, none of these proposed changes have yet been implemented; this means that key lessons for the NEM are limited to considering their proposals, and the work that went into developing and justifying them. This review did not encounter *any* jurisdiction that has an operating FFR-type service, at present.[1] This highlights the need for caution and careful management of stakeholder expectations in developing a new FFR-type service in the NEM. Furthermore, EirGrid is the only example of another jurisdiction that will soon introduce an FFR-type service, and they have elected to specify a 2-second response time. This is considerably slower than the capabilities of some technologies (some of which can respond within 20ms), and is likely due to EirGrid's extensive analysis and resulting caution around the challenges associated with robust detection and measurement of high RoCoF events.

Some jurisdictions (EirGrid/SONI, MISO and CAISO) are also introducing new ancillary service products for managing ramping and variability over timeframes longer than a dispatch interval. These are discussed further in the insights below.

Insights for the NEM

Collaboration with EirGrid/SONI on new ancillary services

EirGrid/SONI are the most advanced in the development and implementation of a comprehensive frequency control ancillary services framework, to operate in a system with

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[1] PJM's fast regulation service is provided by fast-reacting batteries, but is controlled via AGC, and therefore is technically distinct from a fast active power injection in response to a contingency event.

high RoCoF exposure and large quantities of variable generation. In particular, they are about to introduce a 2-second FFR-type service, which could provide a model for a similar service in the NEM. To our knowledge, this will be the first practical demonstration of a service of this kind, in any jurisdiction.

EirGrid/SONI's "Qualification Trial Process" may also be of interest. This process aims to demonstrate the capabilities of emerging technologies for delivering the relevant frequency control services (including the FFR-type service). Results are expected in mid-2017.

AEMO could explore the potential for collaborating with EirGrid/SONI to share information and insights through their experience implementing these new services. This could also offer value to EirGrid/SONI, given the sophisticated and efficient frequency control ancillary services framework already in operation in the NEM [14].

Fast post-fault active power recovery

EirGrid/SONI have established an explicit ancillary service for fast post-fault active power recovery (requiring a maximum of 250 ms to return to 90% active power, post-fault). Active power recovery of non-synchronous generators post-fault can be a significant issue, potentially exacerbating frequency disturbances, and challenging the delivery of FFR-type services. EirGrid/SONI's experiences with this service may provide a model for a similar approach in the NEM.

Ramping services

EirGrid/SONI, MISO and CAISO have all introduced products that aim to procure ramping services, over timeframes longer than a dispatch interval. These are seen as important in MISO and CAISO to ensure adequate system flexibility to meet large, long timescale ramps caused by growing renewable penetrations, and to improve price signals for flexibility.

AEMO could conduct an analysis to determine the NEM's likely future ramping requirements, to determine whether this could be an issue, and explore the potential for improving price signals by introducing an explicit ramping product. Careful consideration should be given to the differences between the NEM and these other jurisdictions with regards to day-ahead markets and other frameworks that may limit or distort effective price signals for flexibility.

Adjusting existing services

ERCOT spent many years developing a comprehensive new ancillary services framework, only to have it ultimately rejected in May 2016. The most important lessons from the ERCOT experience may be that effective stakeholder engagement is essential for significant market changes. Market participants must support the proposed changes, or they are unlikely to be adopted, regardless of the careful demonstration of clear benefits and good market design.

Other aspects of frequency control

Reviews comparing frequency control costs have found that frequency control in the NEM is significantly less expensive than in many other jurisdictions (such as Ireland, Great Britain, New Zealand, Germany and Spain). This suggests that the NEM can probably offer valuable insights on frequency control frameworks to other jurisdictions rather than the reverse. The low cost of FCAS in the NEM is likely to be due to a range of factors, including procurement through a competitive, five-minute market, in real-time, from a wide range of potential providers, co-optimized with energy, across the entire NEM market (in most periods).

However, this review found a number of other insights that the NEM can draw from international jurisdictions on other aspects of frequency control, as outlined in the insights below.

Insights for the NEM

Sculpted minimum regulation requirements

International studies have found that the variability of wind and PV generation depends upon their level of operation. For example, PV doesn't contribute additional variability overnight (since they are not operating). For wind generation, variability has been found to be lower during periods when they are operating at their extremities (high or low generation), and highest when wind turbines are operating around their mid-point (when the turbine power curve is steepest). This creates opportunities to anticipate the level of power system variability from wind and PV, and to provide the system operator with additional tools to pre-emptively and efficiently manage that variability (by scheduling more regulation services when required, for example).

Frequency control capabilities

Other jurisdictions (such as Great Britain) have mandatory requirements for all generators (including wind farms) to have the *capability* to provide a wide range of frequency control services (even if these are never called upon in practice).

Generators installed today are anticipated to remain in operation for 10-30 years, and it is clear that new providers of frequency control services will be required in future (given anticipated retirement of plant that currently provide these services). Retrofit of these capabilities (including the necessary calibration, testing, and verification) could be much more costly and complex than including the capability when the plant is first installed (and the OEM is already involved in the testing and verification process). For these reasons, it may be prudent to encourage the inclusion of frequency control capabilities in new entrants.

International analysis suggests that wind farms should be capable of providing all of the frequency control ancillary services specified in the NEM, if designed to include this capability.

Over-frequency response

This review has mostly focused on management of under-frequency disturbances (caused by an unexpected loss in generation). However, over-frequency events are also a concern, and their management will similarly become more challenging as inertia levels go down, and RoCoF levels go up. This suggests that new approaches to manage over-frequency events may be required.

International studies indicate that wind farms and PV are capable of providing an effective over-frequency response (reducing active power rapidly), if designed with this control capability (often through a droop response). Unlike a primary frequency response for under-frequency, this does not require pre-curtailment of the farm, and therefore can be achieved with a minimal opportunity cost.

A number of other jurisdictions require a mandatory over-frequency response from non-synchronous generation; this review found requirements of this nature in the grid codes for Ireland, South Africa and ERCOT.

Ramp Rate Limitations

Some other jurisdictions (Denmark and Hawaii) have introduced mandatory ramp rate limitations for variable generation. In Denmark this is negotiated during the connection process, while in Hawaii strict ramp rate controls are required.

A similar approach could potentially be applied in the NEM, but should be carefully examined via a cost-benefit analysis prior to implementation. In particular, since frequency control depends upon the system-wide supply-demand balance, there are considerable benefits from aggregating various sources of variability, and managing imbalances at the largest scale possible. This suggests that ramp rate limitations on individual plant should only be applied as a last resort, and only where there is a need to manage local considerations (such distribution network issues, for example).

1 INTRODUCTION

This report aims to explore international experiences in the adaptation of frequency control measures to non-synchronous and variable technologies, and draw out key insights for the Australian National Electricity Market (NEM). It seeks to answer the following key questions:

- Which other power systems can provide the most valuable insights for the NEM on frequency control?
- What issues have they encountered? How are those issues being investigated and addressed?
- What can the NEM learn from their experiences so far?
- What is the best way to continue to learn from their experiences?

The review examined international experiences in frequency control across all timeframes and types. The assessment indicated that relevant insights for the NEM fall into the following categories:

1. **Experiences with high RoCoF** – What possible failure mechanisms for high Rates of Change of Frequency (RoCoF) have been identified in other jurisdictions? What have other power systems found to be their secure technical envelope for high RoCoF?
2. **Fast Frequency Response (FFR) to mitigate high RoCoF** – What can international analysis and experiences tell us about the use of a Fast Frequency Response to mitigate high RoCoF?
3. **Storage technologies for frequency control** – What can we learn from international experiences with batteries and other storage technologies for frequency control?
4. **Demand response for fast frequency control** - What can we learn from international experiences with demand response for fast frequency control?
5. **Emulated inertia from wind turbines** – What can we learn from international experiences with emulated inertia from wind turbines?
6. **The design of new frequency control ancillary services** – What new frequency control ancillary services have other jurisdictions introduced (or considered)? How have they been specified, and why?
7. **Other aspects of frequency control** – What are the other potential lessons from other jurisdictions, on the broader aspects of frequency control?

The jurisdictions that were found to contribute insights on these topics are summarized in Table 4, with high level details on their power system for reference. Details are also provided for the NEM and the South Australian region for comparison.

Table 4 - Jurisdictions investigated in this review

Jurisdiction	System/Transmission Operator	Notes
Australian National Electricity Market (NEM)	*Australian Energy Market Operator (AEMO)*	*Demand: 15 - 35 GW* *Interconnection to other systems: None*
South Australia (NEM)	*Australian Energy Market Operator (AEMO)*	*Demand: 1 – 3.4 GW* *Interconnection to other systems: 1 AC, 1 DC* *Non-synchronous generation: 42.5% (1.5 GW wind, 600 MW PV)*
Brazil	Operador Nacional do Sistema Elétrico (ONS)	-
California (USA)	California Independent System Operator (CAISO)	-
Cyprus	Cyprus Transmission System Operator	Demand: 0.4 – 1.1 GW [15] Interconnection to other systems: None [15]
Denmark	Energinet.dk	-
Germany	TransnetBW GmbH, TenneT TSO Gmbh, Amprion GmbH, 50Hertz Transmission GmbH	-
Great Britain	National Grid	Interconnection to other systems: 3 HVDC links to France, Netherlands & Northern Ireland (3,500MW) [15]
Hawaii	Hawaiian Electric	Interconnection to other systems: None
Ireland/Northern Ireland	EirGrid/SONI	Demand: 2.3 – 6.8 GW Interconnection to other systems: 2 HVDC
Mid-continent ISO (USA)	MISO	-
New Zealand	Transpower	Interconnection to other systems: None
Nordic countries (Norway, Finland, Sweden, Denmark)	Svenska kraftnät, Statnett SF, Fingrid Oyj, and Energinet.dk	-
Ontario (USA)	Independent Electricity System Operator (IESO)	-
PJM (USA)	PJM	-
Québec, Canada	Hydro-Québec TransÉnergie	Demand: 14 – 40 GW [16]
South Africa	Eskom	-
Texas (USA)	Electricity Reliability Council of Texas (ERCOT)	Demand: 22 – 70 GW [3] Non-synchronous generation: 12 GW wind
Western Interconnection (USA)	Many	Demand: 126 – 151 GW

2 BACKGROUND

Power systems around the world are experiencing a rapid growth in wind and PV technologies, which are different from conventional technologies in two important ways that influence frequency control. Wind and PV are:

- **Non-Synchronous** – As non-synchronous technologies (such as wind and PV) displace synchronous technologies (such as coal and gas) the amount of inertia in the power system decreases. Inertia acts to limit the Rate of Change of Frequency (RoCoF) following a disturbance (an unexpected loss of generation or load). This means that in low inertia systems, frequency control measures must act more quickly to arrest the frequency change, and maintain frequency within the required bounds [1]. This effect is significant for managing frequency control over periods of seconds and less.
- **Variable and uncertain** – Wind and PV have variable and somewhat uncertain availability. This means that power systems with a large proportion of wind and PV will need to manage more variability and uncertainty, including larger and more frequent minor imbalances in supply and demand. These imbalances are typically managed through regulation frequency control measures [1]. This effect is significant for managing frequency control over periods of minutes and hours.

This means that most of the international experiences in frequency control adaptation (as summarized in this review) revolve around these two key areas: 1) Managing power systems with low inertia (and therefore high RoCoF), including the potential use of emerging technologies for faster frequency control, and, 2) Managing increasing variability and uncertainty.

2.1 Managing high RoCoF

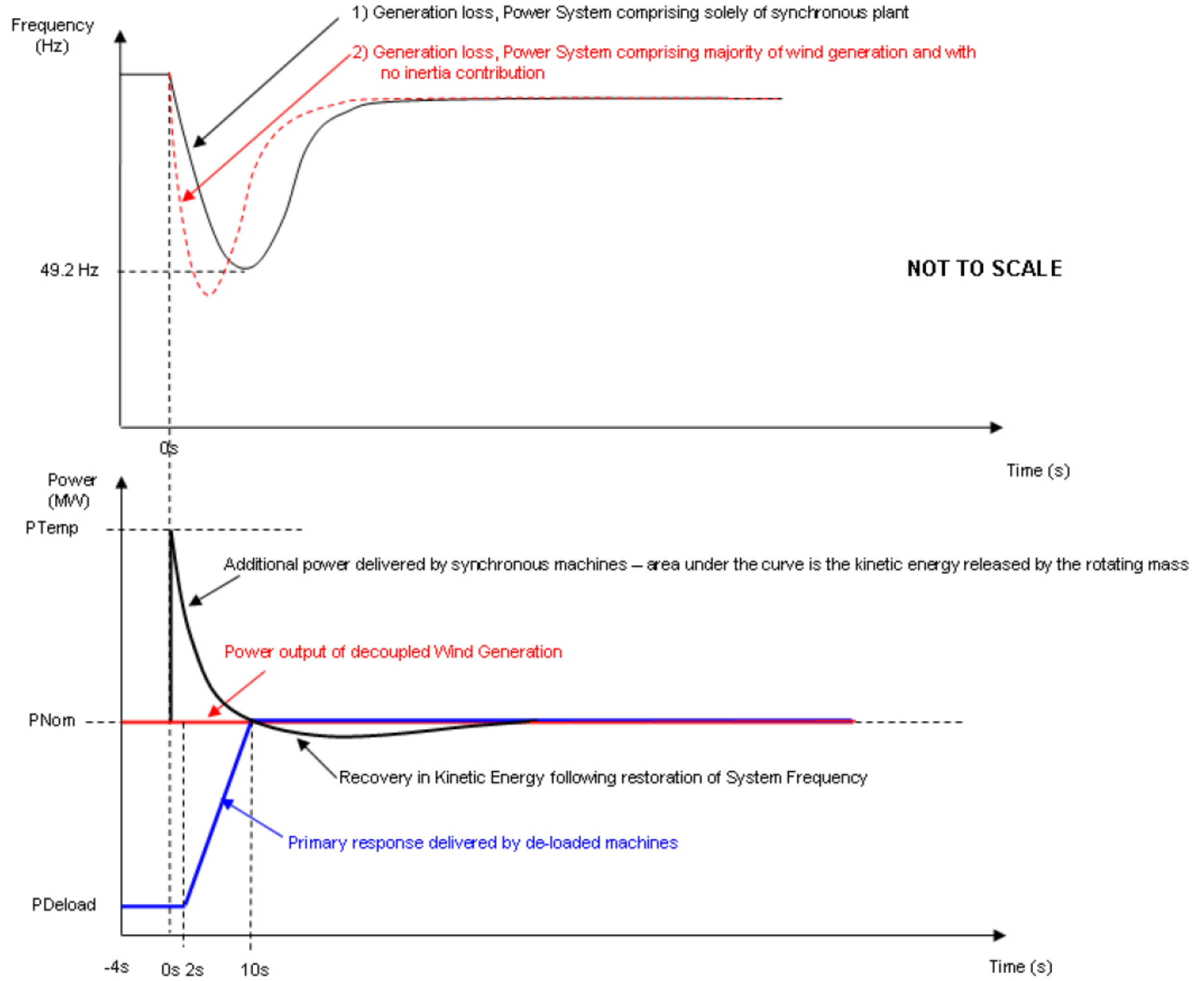
Sudden frequency disturbances can occur due to the loss of load or generation in the power system. The larger the amount of synchronous inertia connected to the system, the slower the Rate of Change of Frequency (RoCoF) to any sudden disturbance and the greater the damping effect. Inertia is provided naturally by the energy stored in the rotating mass of the shaft of the electrical machines, including both directly connected (synchronous) generators and motors [17]. Large synchronous generators are the main sources of synchronous inertia, and play a major role in limiting RoCoF and in the containment of system frequency changes following an unscheduled loss of generation or demand [17]. The "instantaneous" RoCoF (occurring immediately following the disturbance) can be estimated as [18]:

$$\mathrm{RoCoF\ (Hz/s)} = \frac{50\ \mathrm{Hz}}{2}\left(\frac{\mathrm{Contingency\ size\ (MW)}}{\mathrm{Synchronous\ inertia\ (MW.s)}}\right)$$

Wind turbines provide little or no inertia to the system (except in the case of older, simpler induction generator designs, which do provide a small inertial contribution). This is because in both doubly-fed induction generator and full converter designs, the wind turbine's rotating mass is decoupled from the transmission system by either AC/DC converters, or controller actions which offset the inertia effect. These newer wind technologies therefore cannot be used in the conventional sense as sources of "natural" inertia for the purpose of frequency response [17]. Similarly, solar photovoltaic installations do not contain any rotating parts, and therefore have no natural inertia.

As wind and PV displace synchronous generation in power systems, the amount of synchronous inertia connected to the system falls, and the potential RoCoF levels increase, as illustrated in Figure 1. Beyond a certain level, this challenges the ability of the system to remain within secure frequency limits. High RoCoF can be problematic for a number of reasons; it can cause tripping of generation, and if the RoCoF is sufficiently extreme, emergency control schemes such as Under Frequency Load Shedding (UFLS) may not operate properly to prevent system collapse [1].

Figure 1 - The effect of reduced system inertia on the management of a large infeed loss (contingency event) [19]



In the Australian National Electricity Market (NEM), this issue is particularly pertinent in the South Australia region, which now has very low levels of synchronous inertia in some periods, and is connected to the rest of the NEM through a single AC interconnector. This means that if there is an interconnector outage, South Australia can become electrically separated from the remainder of the NEM, and in that event could experience very high RoCoF [1]. AEMO has identified that the secure operating envelope for RoCoF is highly uncertain in South Australia at present, and needs to be better characterized [1]. Therefore, an aspect of this review has focused on international experiences in establishing the secure operating envelope for RoCoF (in Section 3).

There are a range of options for mitigating high RoCoF. Maintaining a minimum level of synchronous inertia is an effective, robust and well-demonstrated approach, but it may become expensive as the level of non-synchronous generation grows. Therefore, a number of jurisdictions are now considering the use of more rapid frequency response capabilities of emerging technologies, to provide a rapid power injection (a "Fast Frequency Response") to arrest the frequency decline. The international work to characterize and implement technologies of this nature forms a significant part of this review, in Sections 0, 5 and 0. Section 8 also explores the new ancillary services specified in other jurisdictions, many of which are focused around Fast Frequency Response.

2.2 Managing variability

Wind and photovoltaic generation also have variable and uncertain availability. This means that they contribute additional variability and uncertainty to the power system, which increases the potential for short-term supply-demand imbalances. These imbalances are typically managed via regulation frequency control services (a generator or load that varies their active power, usually via a centrally controlled Automatic Generation Control signal, to correct the minor supply-demand imbalances).

Growth in wind and PV will likely necessitate changes to regulation services, and may create the need for additional services to manage ramping capabilities over longer timeframes. The changes implemented, and impacts observed in other jurisdictions in this regard are discussed throughout this report.

2.3 Frequency control in the NEM

In the NEM, frequency is managed via "Frequency Control Ancillary Services" (FCAS). This includes two services for Regulation (raise and lower), and six services for managing contingency events (raise and lower, each for response times of 6 seconds, 60 seconds and five minutes).

In light of the challenges described above, this FCAS framework may need to adapt in order to maintain system frequency within the required limits in future. This review aims to contribute insights into potential ways this framework should adapt, given international experiences.

3 EXPERIENCES WITH HIGH ROCOF

This section of the report explores international experiences with high RoCoF, including the RoCoF exposure experienced to date, studies to project future levels of RoCoF, and work programs to establish the secure technical operating envelope for RoCoF.

3.1 EirGrid/SONI (Ireland/Northern Ireland)

As illustrated in Table 5, Ireland is similar to South Australia in a number of ways, having a similar level of demand, and sourcing a large proportion of energy from non-synchronous generation. Importantly, Ireland does not have any AC interconnectors to other systems. This means that they do not have access to the synchronous inertia in other power systems, and have therefore encountered RoCoF challenges at a relatively lower renewable penetration level than other power systems.

Table 5 - Comparison of Ireland and South Australia

	South Australia	Ireland
Demand	1 – 3.4 GW	2.3 – 6.8 GW
% of energy from non-synchronous sources (2015)	42.5% (1.5 GW wind, 600 MW PV)	23% (wind)
Interconnectors	1 AC 1 HVDC	2 HVDC

3.1.1 Program of work

In 2009, EirGrid (the transmission owner and operator for Ireland) and SONI (the electricity system operator for Northern Ireland) initiated a suite of studies (entitled the Facilitation of Renewables) designed to examine the technical challenges related to achieving ambitious renewable energy targets [20, 21, 22]. These studies (published in 2010) identified RoCoF as one potential challenge that needed to be addressed. The modelling found that the system non-synchronous penetration (SNSP)[2] needed to be limited to 50% to maintain system security in the event of frequency disturbances, unless RoCoF relays at distribution connected wind farms and other generators were disabled or adjusted [20].

Following the Facilitation of Renewables report [20], the Single Electricity Market (SEM) Committee (the regulatory authority) requested that EirGrid/SONI provide advice on the implications for the development of the power system, and any priority actions the

[2] SNSP is a measure of the non-synchronous generation on the system in an instant. It is a ratio of the real-time MW of generation from wind and HVDC imports, to demand plus HVDC exports.

Regulatory Authorities should be taking. In response, in 2011 EirGrid/SONI prepared a detailed report [22], outlining a comprehensive work plan, and launching the "Delivering a Secure, Sustainable Electricity System" (DS3) program. This program aims to address a range of renewable integration challenges, including the management of high RoCoF [22].

The current RoCoF capability required of all units in Ireland is 0.5 Hz/s, specified in the Grid Code (generators are obliged to stay synchronized for RoCoF values up to this level)[3] [11, 23]. Following the publication of the 2010 study [20], EirGrid formally wrote to all generators in Ireland (Quarter 4, 2010) requesting confirmation of their technical capability with regard to RoCoF. The majority of the replies indicated that the generators were compliant with the Grid Code requirement to withstand RoCoF values up to 0.5Hz/s, but did not specify if they could withstand higher RoCoF values [23]. EirGrid subsequently wrote to the generators again in early 2011 seeking further information on RoCoF capabilities. The majority of responses did not clearly address the issue. It was decided that an alternative approach, using the Grid Code Review Panel as a forum, was required, as formal modification proposals to the Grid Code would enable generators to formally respond on their capabilities [23].

In Northern Ireland, since 2001, there has been a RoCoF requirement in the Minimum Functional Specification of 1.5Hz/s for all transmission connected plant [23], although this has not been rigorously tested, and there is no confidence that units installed prior to this date can meet this standard [11]. This specification only applies to new connecting plant, and does not apply to incumbents connected prior to 2001. SONI carried out a similar exercise at the beginning of 2012, contacting generators in Northern Ireland for information on their RoCoF capability. The main findings were that that over 85% of connected wind generation use vector shift rather than RoCoF. The responses from conventional generators were not as comprehensive but generally stated that the RoCoF capability would be in the region that is mentioned in the Minimum Functional Specification applying in Northern Ireland (1.5Hz/s).

EriGrid/SONI originally proposed to increase the RoCoF standard to 4 Hz/s (in October 2011), but this was met with significant opposition from generators [8, 23]. They subsequently proposed to increase the standard for RoCoF withstand capability required of

[3] The timeframe over which this is measured is not specified in the current Grid Code (EirGrid/SONI 4 September 2012).

all plant (including incumbents) to 1 Hz/s (measured over 500ms), to allow operation with a higher SNSP [24, 11].

Studies in PSS/E indicated that Northern Ireland is exposed to RoCoF in excess of 2Hz/s, following a fault and system separation [25]. For this reason, EirGrid/SONI recommended a RoCoF standard of 2Hz/s in Northern Ireland, until further North-South tie-lines were constructed (a second tie-line is under construction at present) [8]. However, the Northern Ireland generators argued that this was not justified, leading to SONI seeking a standard of 1Hz/s, consistent with the anticipated all-island position [11].

The increase in the RoCoF standard to 1Hz/s (measured over a 500ms rolling window) was approved in principle by the Commission for Energy Regulation (CER) and the Utility Regulator (UR) of Northern Ireland in April and May 2014 [26], but will only come into effect following confirmation that system security can be maintained. The approval required three strands of work [24]:

1. **Generator Studies Project** – Generators are required to undertake appropriate studies, and make a declaration to EirGrid regarding their level of compliance within 18-36 months. Higher priority units are to be completed first (those with high running hours, and frequently operating at times of high wind). High priority generators were required to complete studies by May 2016 [27]; at the time of writing this report, it is understood that some initial generator studies reports had been completed.
2. **TSO-DSO Implementation Project** – Transmission System Operators (TSOs) and Distribution System Operators (DSOs) are required to make changes to Loss of Mains projection in the distribution system such that high RoCoFs will not disconnect large quantities of embedded generation [26], and to monitor of any potential impact of high RoCoF on demand customers and quality of supply.
3. **Alternative Solutions Project** – The CER identified a risk that the implementation of the new 1Hz/s standard could take longer than 18-36 months, and therefore required a strand of work to explore "alternative" (and possibly complementary) solutions. This is discussed further in the following section (on the specification of new ancillary services).

3.1.2 Timeline of work

The original program of work proposed by EirGrid/SONI extended over three years (2012 to 2014), with generator testing completed by the end of 2013 [11]. However, the CER/UR decision was only reached in mid-2014 [24], and the project formally commenced on 21st November 2014. High priority generating units were scheduled to complete studies by end of May 2016, and low priority units by November 2017, as summarized in Table 6 [28, 29]. EirGrid/SONI report that the project has been progressing in line with the overall planned timelines [30].

Table 6 - Timeline of work

Milestone	Date
Change of RoCoF standard approved in principle by the Commission for Energy Regulation (CER) and the Utility Regulator (UR) of Northern Ireland	April/May 2014
RoCoF project formally commenced	21st November 2014
High priority generating units to complete studies	31st May 2016
Medium priority generating units to complete studies	30th November 2016
Low priority generating units to complete studies	30th November 2017

Each generator was requested to provide a detailed project plan, to which progress could be monitored and measured against. The CER reports that progress in general has been very positive, and no significant technical issues have been raised [29]. Twelve of the fourteen high priority units anticipate delivery of their studies by the June 2016 deadline [29].

3.1.3 Generator testing

The requirement for generator studies on each individual unit proved highly contentious. There is no test that can reliably check that a generator will withstand a high RoCoF event [24], short of deliberately instigating a contingency event on the transmission system, with the associated risk of loss of system security [8]. This is unlikely to be palatable in most jurisdictions. A more appropriate approach is to install disturbance recorders on all plants, and monitor their responses to high RoCoF events that may occur "naturally" over time [8]. Many plants are already fitted with suitable equipment [8].

This means that it is necessary to rely upon the generators' assessments and "certification" of their units' capabilities. The generators, in turn, have no option but to rely upon their Original Equipment Manufacturers (OEM's) for guidance on RoCoF capabilities [8]. The OEMs themselves may not have much further insight; the issue of RoCoF might not been studied in detail by OEMs in the past, and their "comfort" with the existing RoCoF requirement of 0.5Hz/s is based mainly on historic worldwide operating experience [8]. There is limited design or analysis documentation available regarding this issue. Real-world events involving high RoCoFs have been historically rare, so there is little relevant operating experience [8].

The CER noted that studies to determine RoCoF capabilities have never been carried out previously, and it is therefore not possible for Ireland to utilize prior international experience [24].

Individual assessment for each plant is required [8], and could involve various types of evidence of RoCoF withstand capabilities; for example, generators could provide documentary evidence from the OEMs, or could carry out frequency injection tests to simulate the impact of an event on the plant's control system and auxiliary equipment [23]. Care needs to be taken when interpreting testing results; for example, a 1 Hz injection test is likely to be a significantly less onerous event that a genuine system frequency excursion, and the successful performance of the injection test should not be taken as evidence that the plant can accommodate a real-world frequency excursion of this magnitude or RoCoF [8].

Generators indicated that the extensive studies of each unit required would take between 12 and 18 months to complete [5]. One OEM indicated a duration of 18 months to study a single plant, with little opportunity to run multiple studies in parallel. This would suggest timescales of 8-10 years to study all of the plants on the system [8].

Conventional generators argued that it would be costly to determine the exact RoCoF capability of their unit, and to modify the unit if the current capability is below the proposed Grid Code modification. GE estimated the associated costs of testing to be around US$1.5m per CCGT [11, 8], while another source estimated costs of a similar level at around of €900k per plant [8]. The challenges were primarily related to the technical complexity of the studies themselves, the requirement to rely upon OEM's (multiple OEMs in some cases) actively engaging with the generator, and resource constraints within the OEMs even if active engagement is achieved [11]. GE highlighted that the resources and systems needed for analysis of this kind are of a very specialist nature, and therefore may not be readily available [8]. Generators noted that their advice from manufacturers is that this type of study has not been undertaken by any of the OEMs involved, for any other country or network [8]. Some generation owners experienced considerable difficulty in engaging their OEM, which in many cases had itself undergone significant organizational changes since the plant was commissioned [8].

In light of the considerable cost anticipated for undertaking generator studies, generators requested that the costs associated with the technical studies be recoverable. However, the

CER decided that they will not provide for cost recovery of the studies, since compliance with the Grid Code is the responsibility of the generator, as are any costs required to achieve or maintain compliance [24].

It was considered whether a generic study could be undertaken, to identify the degree of impact of RoCoF on typical conventional plant [8]. If generating units were sufficiently similar, this could provide valuable insights to guide the prioritization of further analysis. However, in Ireland it was felt that each unit is sufficiently bespoke that individual studies will be required for each generator. Furthermore, OEMs are likely to require bespoke testing of their units in order to "certify" their capabilities. For this reason, all generators have been required to undertake their own testing, rather than commissioning OEM assessments centrally [8].

If the generator studies show that some units are not compliant with the proposed new RoCoF standard, it may be possible to avoid dispatching those plant during periods where there is a risk of high RoCoF [23]. However, this would significantly complicate the operation of the power system.

3.1.4 Impacts on synchronous generators

Three potential concerns were identified for conventional generators, when exposed to high RoCoF events [24]:

1. **Cascading tripping** – operational consequences where a unit either fails to deliver the required response during a RoCoF event or trips, leading to loss of further electrical power from the system. This has the potential to initiate further cascade tripping events, leading to load shedding, system islanding or system blackouts [31].
2. **Wear and tear** – Repeated high RoCoF events could cause increased wear and tear, and negatively impact the commercial life of generators plant. This impact will be highly dependent upon the frequency of high RoCoF events. If they are infrequent, as is expected, then there will be minimal impact on the life of the unit.
3. **Safety concerns and catastrophic damage of generating units** – In the worst case, high RoCoF events could cause a catastrophic failure of a unit, causing safety concerns for station staff. This was assessed to be "highly unlikely" on the basis that units can be expected to undergo more severe network fault events without catastrophic failure [8].

These are each discussed further below.

3.1.4.1 Pole slipping

EirGrid/SONI commissioned DNV-KEMA (now DNV-GL) to perform a study to analyse the RoCoF withstand capabilities of the synchronous generators in Ireland [5]. They developed a high-level spreadsheet model to conduct the analysis; the model did not take into account speed governor action or system damping effects, and the authors acknowledged that this may mean it is more pessimistic than reality, and a full PSSE model could provide more accurate results. The modelling only considers one aspect (synchronous stability), and is more related to mechanical phenomena, as opposed to electrical dynamic effects. It does not examine the protection devices installed at generators, or the associated auxiliary equipment. OEMs consider the impact of network faults when designing their machines (and the associated auxiliary equipment), but have probably not considered high RoCoF events as part of that design process [8]. This means that there is a real possibility that although this modeling indicates an ability of generators to tolerate various levels of RoCoF, it does not capture many potential avenues of failure. The modeling does indicate, however, that the likelihood of significant damage to the plant items (generators, shafts, turbines) is low, based upon the limited information available [8].

Notably, these are the first studies of this kind (analyzing RoCoF withstand capabilities of large synchronous generators) [5]; no other studies of this type were identified in this review.

The main failure mechanism identified in the DNV-KEMA study was pole slipping [5]. Pole slipping is when a synchronous generator falls out of step with respect to the rest of the AC network; the rotor advances beyond a critical angle at which the magnetic coupling between the rotor and the stator fails. The rotor, no longer held in synchronism with the rotating field created by the stator currents, rotates relative to this field and pole slipping occurs [32]. Pole slipping is likely to severely damage the machine [5]. When the pole slip occurs, the magnetic force of the stator is not able to attract the rotor field anymore. Since power is still applied to the rotor, the machine will speed up (as there is no longer an opposing force). At this point over speed protection should engage, but damage may already be done [5].

DNV-KEMA found that pole slipping occurred at around 1.5Hz/s to 2Hz/s, and at 1Hz/s for some units if operating with a leading power factor (especially over the longer duration of the 1Hz drop) [5]. In general, a 2Hz/s RoCoF value was not achievable by most units, apart from the small OCGT and the salient pole Hydro machine. Results for each unit studied are listed in Table 7. If the duration of the event was shortened, higher RoCoF values may be possible; for example, the 260MW CCGT Dual-shaft machine was found to remain stable for a 250ms RoCoF event of -2.2Hz/s under the operation conditions of 100% load and a unity power factor [5].

The point at which pole slipping was observed to occur depended upon whether the unit is operating with a leading or lagging power factor[4] [5]. The results indicated that transient stability of all the generators studied can be maintained for a RoCoF up to 1Hz/s, except in situations where generators are operating at a leading power factor (ie. absorbing reactive power, as could occur at times of light load on the system) [8, 5].

This suggests that the operational modes of sensitive units could be restricted to lagging power factors during periods at risk of high RoCoF, to avoid instability. This would likely apply in light load conditions, or situations where voltage control is required to avoid over-voltages in areas of the network where there is significant generation infeed. These restrictions would reduce options for achieving some aspects of system voltage control, therefore, and would need to be taken into consideration in determining the overall operating regime of the network [8].

The point at which pole slipping occurs was also found to depend upon the inertia of the unit, the number of poles, and the load [5].

In addition to pole slipping, DNV-KEMA's study also identified some incidents of momentary reverse power [5]. During these events, the machine does not necessarily pole slip, but generates for short periods with negative power (i.e. it consumes active power, similar to a motor). Generators are typically protected against motor operation by reverse power protection; if triggered, this will shut down the unit. Normally, these protection relays are set with a threshold of 5% of nominal apparent power, with a delay of a few seconds.

[4] This is explained as follows (DNV-KEMA 8 February 2013): "When the machine is unable to follow the fast reduction in speed, the rotor loses its opposed force from the electricity grid, and will therefore speed up. The fast change of the stator field frequency results here in an inadequate rotor reaction. In other words, the rotor is not able to follow the speed change of the stator field frequency. This reflects back to the amount of attractive force between both stator and rotor fields combined with the inertia of the machine. The attractive force between both fields can be controlled by changing the power factor or/and the load of the machine. This explains why different operating parameters could make the unit capable or not capable of tolerating a certain RoCoF value".

Table 7 - Summary of DNV-KEMA modelled RoCoF withstand capabilities of synchronous generators in Ireland and Northern Ireland [5]. "Yes" indicates stable operation, while "No" indicates a pole slip was observed for power factors of 1 unity or/and 0.85 lag.

<table>
<tr><th rowspan="3"></th><th rowspan="3">Unit size (MW)</th><th rowspan="3">Inertia constant (s)</th><th colspan="7">Stable during RoCoF?</th></tr>
<tr><th colspan="2">0.5 Hz/s</th><th colspan="2">1 Hz/s</th><th>1.5 Hz/s</th><th colspan="2">2 Hz/s</th></tr>
<tr><th>Over 500ms rolling window</th><th>Over 1Hz drop</th><th>Over 500ms rolling window</th><th>Over 1Hz drop</th><th>Over 1Hz drop</th><th>Over 500ms rolling window</th><th>Over 1Hz drop</th></tr>
<tr><td>CCGT single-shaft</td><td>400</td><td>5.5</td><td rowspan="8">Yes</td><td rowspan="4">Yes</td><td rowspan="7">Yes, although pole slip observed for a 0.93 leading power factor operation mode</td><td>Yes, although pole slip observed for a 0.93 leading power factor operation mode</td><td>Yes, although pole slip observed for a 0.93 leading power factor operation mode</td><td colspan="2" rowspan="3">No</td></tr>
<tr><td>CCGT dual-shaft</td><td>260</td><td>6</td><td rowspan="2">No</td><td rowspan="2">No</td></tr>
<tr><td>CCGT Dual-shaft</td><td>140</td><td>9</td></tr>
<tr><td>Steam Thermal (Reheat)</td><td>300</td><td>5</td><td rowspan="2">Yes, although pole slip observed for a 0.93 leading power factor operation mode</td><td>Yes, although pole slip observed for a 0.93 leading power factor operation mode</td><td colspan="2">No. No pole slip observed for power factors of 1 unity or/and 0.85 lag, but negative power generation detected.</td></tr>
<tr><td>Steam Thermal (Once Through)</td><td>250</td><td>4.5</td><td rowspan="3">Yes, although pole slip observed for a 0.93 leading power factor operation mode</td><td rowspan="2">No</td><td colspan="2" rowspan="2">No</td></tr>
<tr><td>Steam Thermal (Fluidized bed peat)</td><td>150</td><td>8</td><td>No</td></tr>
<tr><td>OCGT</td><td>50</td><td>1.5</td><td>Yes, although pole slip observed for a 0.93 leading power factor operation mode</td><td>Yes, although pole slip observed for a 0.93 leading power factor operation mode</td><td colspan="2">Yes, although pole slip observed for a 0.93 leading power factor operation mode</td></tr>
<tr><td>Salient-pole hydro</td><td>30</td><td>2.7</td><td>Yes</td><td colspan="2">Yes</td><td>Yes</td><td colspan="2">Yes</td></tr>
</table>

3.1.4.2 Mechanical stress

DNV-KEMA's study showed that torque values of the machines increase at higher RoCoF values, but remained within the capabilities of the units investigated [5].

EirGrid/SONI noted that generators are designed to withstand normal system events, such as load rejections, synchronization events, and switching events where the step change in active power from the machine is less than 0.5pu [33, 23]. They noted that RoCoF events fall into this category of relatively infrequent system events [23].

The Ireland Grid Code specifies fault ride-through criteria regarding voltage dip magnitude, and compliance with this could result in mechanical stress values far in excess of those estimated in the DNV-KEMA study [6]. During significant voltage dips, which are a common occurrence on every power system, instantaneous or short-duration RoCoF values well in excess of 1Hz/s can be experienced by machines. The forces experienced on the machine shaft during these events are more severe than during a loss-of-generation event, and do not cause catastrophic plant failure or cascade tripping of plant [33, 23]. However, it should be noted that any damage done to machines by transient events is cumulative in nature. Furthermore, the proposed RoCoF requirement of 1 Hz/s measured over a 500ms period is materially more severe than an instantaneous value experienced during a voltage dip event [8].

For example, fault simulations using models of the all-island network have demonstrated that a large CCGT can experience accelerating RoCoFs of 8%/s (4 Hz/s) for a duration of 100ms (during a fault-induced voltage depression) followed immediately by a decelerating RoCoF of 2%/s (1 Hz/s) for longer than 500ms. All synchronous machines on the network are designed to tolerate this kind of event, although not on a frequent basis [8]. However, caution is required in assuming that just because a plant is capable of tolerating a grid fault event, it is also therefore naturally capable of handling an apparently less onerous RoCoF event. RoCoF events might not have been included in the list of design considerations, and the ability to tolerate faults and RoCoF says nothing about the cumulative effect of such events on generating equipment [8].

EirGrid/SONI's review of the literature on grid-induced torsional vibrations in generators indicated that short duration/instantaneous RoCoF values up to 50Hz/s are not uncommon, and do not cause catastrophic plant failure (due to the extremely short duration of the exposure) [34, 23]. There is evidence that sub-synchronous resonance phenomena can excite torsional modes in machines, resulting in shaft failure [35, 23], but this is not currently an issue in Ireland or Northern Ireland to their knowledge [23].

This body of evidence suggests that mechanical stress does not present an immediate risk to the generator, but if high RoCoF events were frequent this could affect the lifetime of the unit, and lead to additional maintenance requirements [5]. EirGrid/SONI estimate a likely occurrence of high RoCoF events on the all-island system of around five events per annum with a RoCoF exceeding 0.5Hz/s; this can be compared with around 30 short-circuit faults on the Irish transmission system per annum, and a smaller number in Northern Ireland [8, 23]. This suggests that the additional wear and tear is not likely to be overly onerous, compared with the mechanical stress already experienced by these units due to transmission faults.

3.1.4.3 Other failure mechanisms

Importantly, the DNV-KEMA report [5] focuses primarily on the issue of plant synchronous stability, yet the submissions from plant owners do not appear to raise this issue as a particular concern [8]. For the generators, it appears to be mainly the effects of high RoCoF events on flame management, torsional effects on the turbine/generator shaft and the generator control systems that are of primary importance [8]. These effects are not readily studied through the type of analysis undertaken in the KEMA study [8].

For example, GE was contacted by generators for advice on RoCoF withstand capabilities of their units, and replied that the consideration of an increase in RoCoF raises a number of complex issues, specifically [8]:

- GE combustion and controls – the ability to handle without LBO (lean blow-out)
- Torsional impacts on GT/ST+GEN rotor shaft train
- Transmission & Generation system stability
- Protection settings
- Other equipment impacts – GT, ST, generator, excitation, Power System Stabiliser application & Balance of Plant (BOP) (e.g. Low Voltage Ride Through) and possible BOP motor load instability.

ESBPG (a generation operator) described the following technical phenomena that would be of concern in their units [8]:

- Flame stability or over-temperature in GTs
- Hydraulic transients in hydro plant
- Additional demands on plant control systems

- Impact on auxiliary plant such as motors (e.g. boiler feed pumps, gas compressors)
- Impact on plant protection systems
- Mechanical integrity – transient torques on machine shafts and turbine blades

It is emphasized that the DNV-KEMA study is helpful in demonstrating the ability of plants to ride through 1 Hz/s RoCoF occurrences in terms of maintaining transient stability, but this is only one factor in the complex set of mechanical phenomena that can affect plant performance and possible degradation in terms of wear and tear as a result of repeated RoCoF occurrences [8].

3.1.5 Impacts on wind generators

Wind farm manufacturers confirmed that their equipment can comply with the new 1Hz/s standard in Ireland [24]. EirGrid/SONI's bilateral discussions with wind turbine manufacturers indicated that 4Hz/s was the RoCoF standard for new turbines [8, 23].

However, many wind farms in Ireland are connected to the distribution system, and are equipped with RoCoF relays as part of their G10 protection functions [36, 20], for anti-islanding protection (as discussed below).

3.1.6 Impacts on distribution networks

In distribution networks, the key issue is the tripping of anti-islanding protection (or loss-of-mains protection). These protection systems are important to prevent embedded generation supplying an electrical island when a loss of mains event has occurred. This is an important safety mechanism.

Loss-of-mains relays observe the frequency at the connection point of the embedded generator. In order to prevent islanding they disconnect the generator in events when the rate of change of frequency exceeds a certain level (the actual settings of this protection are unknown [8], but are estimated in one source to disconnect the generator at around ±0.40 to ±0.55 Hz/s over a period of 500ms [36, 20], and estimated at ±0.5 Hz/s for Ireland and ±0.4 Hz/s for Northern Ireland in another source [5]). For this reason, a key recommendation was to replace the RoCoF protection relays on the distribution networks by alternative protection schemes or increased RoCoF thresholds [20]. The distribution system operator has confirmed that the current protection settings can be modified by adjusting settings and time delays on RoCoF relays to allow for the 1Hz/s standard, but there is a considerable amount of further work to be undertaken in implementation [24, 23].

In Northern Ireland, distribution-connected generation generally use vector shift rather than RoCoF [23]. It is predominantly the earliest wind farms that still use RoCoF protection, and there is evidence that some generators have changed from RoCoF to vector shift protection. Research carried out on loss-of-mains protection has indicated that vector-shift relays can be prone to nuisance tripping if not set correctly, and so it should not be inferred that vector-shift relays are any better or any worse than RoCoF relays [23].

EirGrid/SONI note that there are alternative protection/design philosophies that could be explored for loss-of-mains protection instead of RoCoF relays or vector shift [23], although there may be a cost associated with this, and significant challenges remain to be overcome.

EirGrid/SONI also note that RoCoF protection for anti-islanding is not widely used, apart from Ireland, Great Britain, Belgium, and Denmark. In Belgium and Denmark, the typical settings of RoCoF relays are in excess of 1Hz/s [18, 23]. In Great Britain, the standard setting for RoCoF protection is 0.125Hz/s [23].

Most of the issues in the distribution network will be solved in Ireland by increasing the RoCoF settings on anti-islanding protection to 1Hz/s. Work to quantify the amount of generation plant installed on the distribution network has now been completed, and figures advised to EirGrid [29]. It has also been established that the overwhelming majority of the distribution-connected fleet will be able to adjust protection settings as required, although the logistics of carrying out these changes “should not be under-estimated” [29].

There is some degree of concern around the RoCoF withstand capabilities of embedded generators, particularly for combined heat and power, and diesel plant. Discussions with OEMs are continuing on this aspect.

3.1.7 Impacts on customers

No evidence has been encountered that suggests that demand customers would be adversely affected by high RoCoF. However, the CER directed EirGrid/SONI to monitor the impact of the new RoCoF standard as a part of the implementation project [24]. The TSOs are currently investigating the impacts of high RoCoF on demand customers through engagement with large demand customers, and with the DSOs. The TSOs are also performing study analysis to investigate any potential impacts on demand sites [37].

Stakeholders noted that the impact of high RoCoFs on system demand customers is an important issue that may require further consideration and consultation [8].

3.1.8 Impact of wind generation fault ride-through behavior

In addition to displacing synchronous generation (and therefore reducing the synchronous inertia of the power system), an increasing proportion of wind generation creates complexities in managing voltage dips occurring as a result of faults. When a short circuit causes the collapse of the voltage on the system, inverter-connected generation in the vicinity of the fault will reduce active power output for a period of time, and then take time to recover their output during post-fault recover. During this time, the loss of real power generation coupled with the "lightness" of the system (as inertia decrease with increasing SNSP) leads to higher RoCoF levels with increasing SNSP, than would otherwise be experienced [8]. For example, EirGrid/SONI's modelling shows a very rapid increase in the level of (negative) RoCoF following voltage dips, as the SNSP increases above 40% [23, 8]. EirGrid/SONI suggest that this should be dealt with through better wind farm standards [23, 8].

3.1.9 Analysis of historical RoCoF events

EirGrid conducted analysis of historical events to gain insight into the potential RoCoF withstand capabilities of their system [10]. Results are summarized in Table 8.

Table 8 - Historical high RoCoF events in Ireland [10]

Date	System	Frequency nadir (Hz)	RoCoF (Hz/s over 500ms)	Notes
31 May 1988	Ireland (not connected to Northern Ireland)	48.47	0.9 (measurement duration unknown)	No reports of mechanical failure or cascade tripping of connected generators due to the RoCoF event.
4 August 1988	Northern Ireland (not connected to Ireland)	48.8	0.82	No reported mechanical failures of units or cascade tripping incidents due to the RoCoF experienced in this event.
3 Feb 1994	Northern Ireland (not connected to Ireland)	47.6	3.7	No reports of mechanical failure of generating units on the system.
5 Aug 2005	Ireland (All Island)	48.4	0.35	No generators were reported to have tripped as a result of the RoCoF event.
27 Apr 2010	Ireland (All Island)	49.0	0.27	No other generator units tripped due to the event and no units reported mechanical damage due to the RoCoF.

27 Nov 2010	Ireland (All Island)	48.9	0.29	No other generator units tripped due to the event and no units reported mechanical damage due to the RoCoF.

In all instances, there was no evidence to suggest that generation tripped out purely due to a RoCoF event, or that any conventional unit experienced any damage due to the RoCoF event [10].

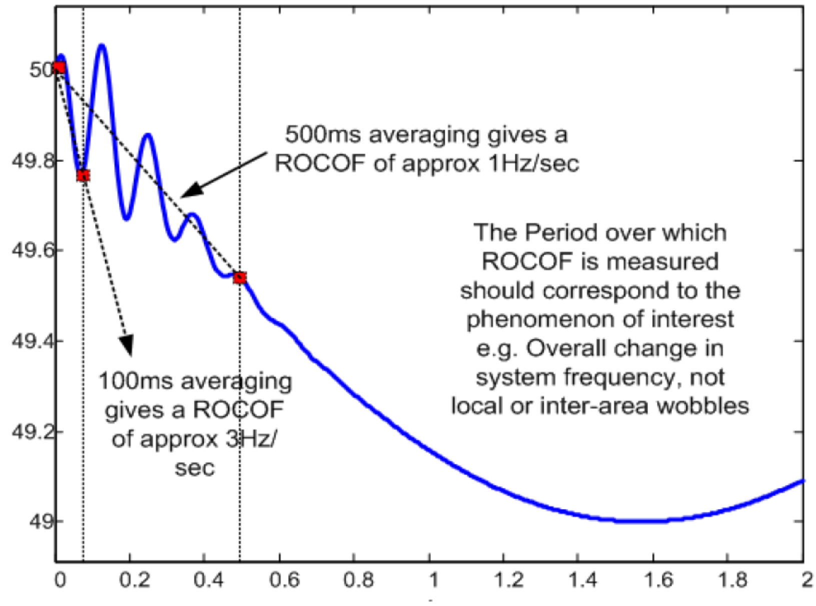
3.1.10 RoCoF measurement timescale

EirGrid/SONI note that one of the key lessons from their many studies and long program of work has been that the measuring window over which the RoCoF is calculated is just as important as the RoCoF value itself [23].

The studies conducted by EirGrid/SONI have showed that RoCoF values are closely related to the window over which they are measured. For example, a RoCoF value calculated using a measuring window of 1ms, could be far greater than a value calculated using 100ms or 500ms as the relevant time frame, as illustrated in Figure 2. Note that this figure is not a measurement, and is an illustrative example only.

EirGrid/SONI determined that 500ms is an appropriate time frame to calculate RoCoF, as it usually takes this length of time for the generators to return to a coherent state. If a shorter measuring window was used, then EirGrid/SONI would be forced to seek a higher RoCoF standard [23].

Figure 2 – Illustration of the significance of the RoCoF measurement window [23]



The generators noted (in their responses to the proposed change of the RoCoF standard) that the generation unit is exposed to the frequency during the event, regardless of how it is measured, and so may trip during an event measured at 1Hz/s RoCoF, because the actual frequency changes were more severe than the average over 500ms suggested [24]. The CER noted that alternative measurement windows could be considered, but a shorter window may necessitate an increase in the RoCoF level.

EirGrid/SONI proposed the 500ms measurement window, since this is the time that it takes for the generators to return to a "coherent state" [23]. It's also cited as aligning with the required recovery time for wind generation post-fault [8].

There are further subtleties in the precise definition of the RoCoF standard. The EirGrid proposed modification is stated as RoCoF up to and including 1Hz/s, "as measured over a rolling 500ms window". However, DNV-GL's modelling found that the RoCoF withstand capabilities of synchronous generators are highly sensitive to the total duration of the RoCoF event. Their modelling showed that most generators could achieve compliance with a 1Hz/s standard over an *absolute time window of 500ms*. However, the capabilities of generators were found to be significantly reduced when the 1Hz/s RoCoF was sustained over a full second (for a 1Hz absolute drop) [5]. This means that meeting the rolling 500ms window standard could pose challenges for synchronous generators in the EirGrid system [6].

3.1.11 Localised RoCoF measurement

EirGrid also noted that RoCoF at different points in the system can vary significantly under transient conditions. Within the initial 100ms after a frequency disturbance, a wide range of RoCoF values can be measured, depending upon the location in the system. In one particular study, RoCoF levels as high as 2.71Hz (and as low as 0.23Hz/s) were measured at some buses in the initial 100ms, while a measurement window of 500ms yielded RoCoF levels within the range 0.41 – 0.53 Hz/s at all buses investigated [38]. During transient events, generator rotor speeds may differ from each other due to local and inter-area interactions. In order to obtain a consistent system-wide measurement of RoCoF, the electrical transients need to be removed from the analysis, and only the mechanical transients on the system should be considered. This can be achieved by extending the measurement window [38]. This indicates that it is difficult to determine a consistent system-wide RoCoF measurement with a 100ms time window, while a 500ms window yields a better indication of system-wide RoCoF.

3.1.12 Other related activities

EirGrid/SONI apply various decision support tools in their control centers. This includes a Wind Security Assessment Tool (WSAT), which provides near real-time assessment of voltage stability and transient stability of the Irish power system. It is intended to extend these capabilities to include frequency stability assessment, and to this end the tool is undergoing validation against real-life events [23].

EirGrid/SONI are also consulting with conventional generator owners to investigate lowering minimum stable generation levels on the existing conventional plant portfolio [31]. This will aid in the provision of the levels of synchronous inertia required on the system [31].

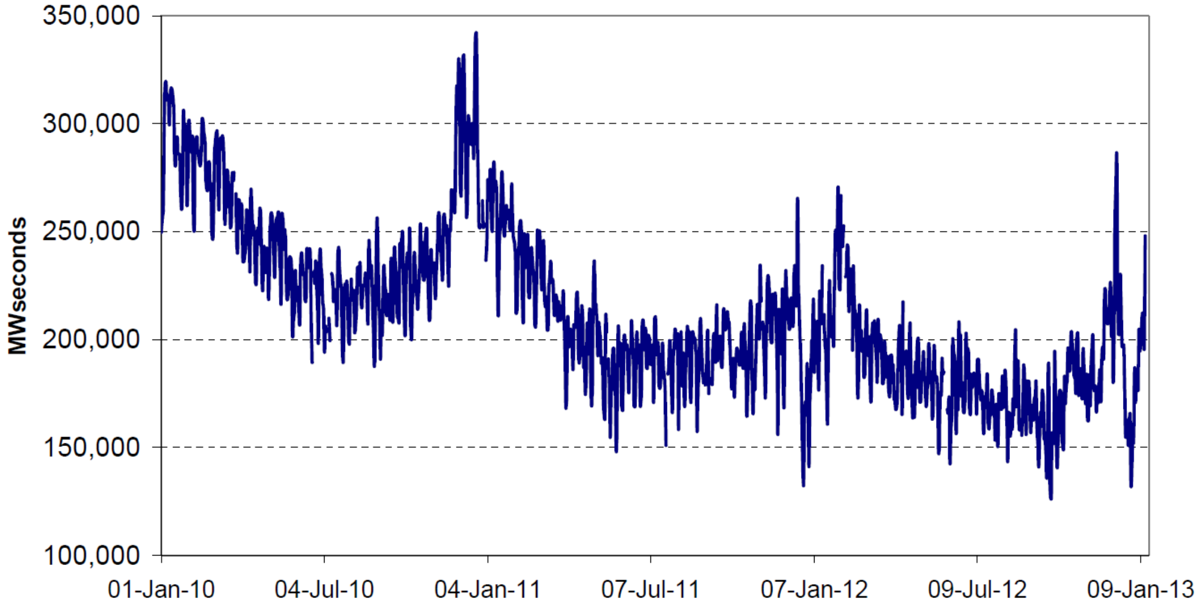
3.2 National Grid (Great Britain)

Great Britain's electricity demand is around 56GW, supplied by around 75GW of generating capacity. Approximately 23.5% of electricity is supplied from renewable sources, with 13% from non-synchronous sources (wind and solar PV). Great Britain has HVDC links to other jurisdictions, but no AC links, and therefore may provide a reasonable analogue for the NEM with regards to RoCoF.

National Grid have noted falling levels of synchronous inertia since 2013 [39], as illustrated in Figure 3. However, note that the levels of inertia illustrated in Figure 3 are an order of magnitude greater than those in South Australia (now below 2,000 MWs in some periods).

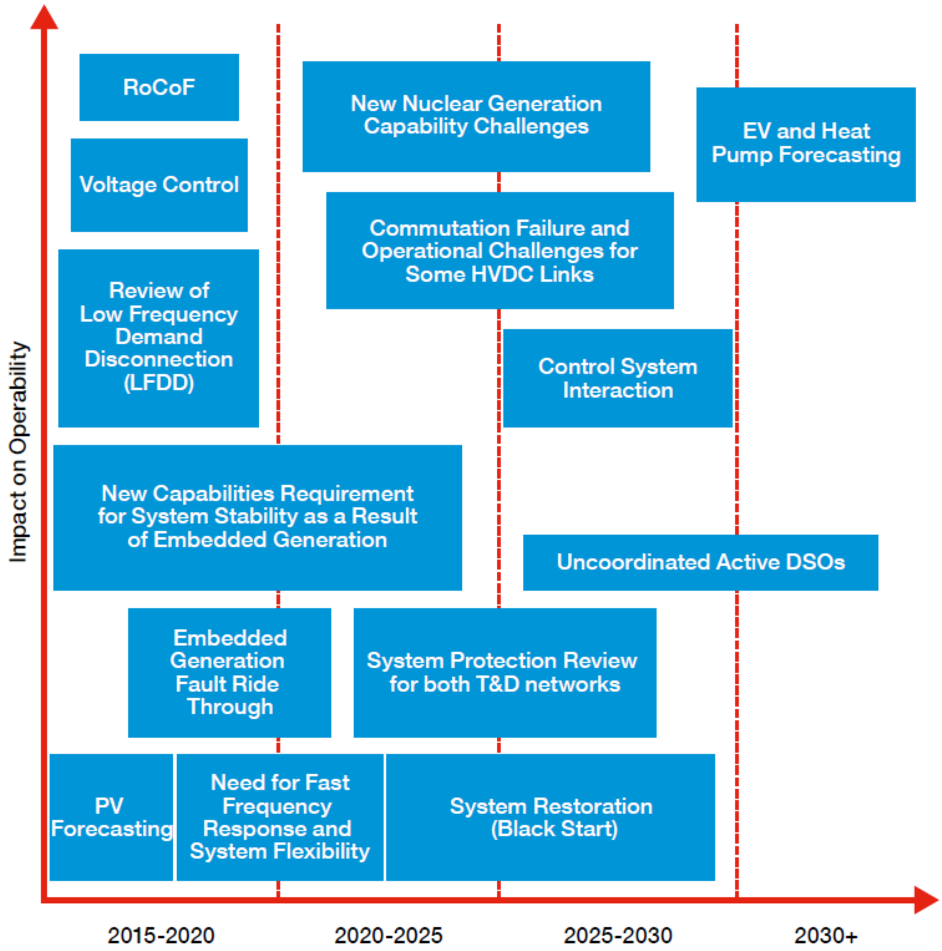
Projections for 2020 predicted an average system RoCoF for loss of 1800 MW, under high wind, high import conditions, at 0.6 Hz/s [39] (measured over 500ms).

Figure 3 - Stored energy (synchronous inertia) in transmission contracted synchronized generation for the 1B Cardinal Point (overnight minimum demand point) [39]



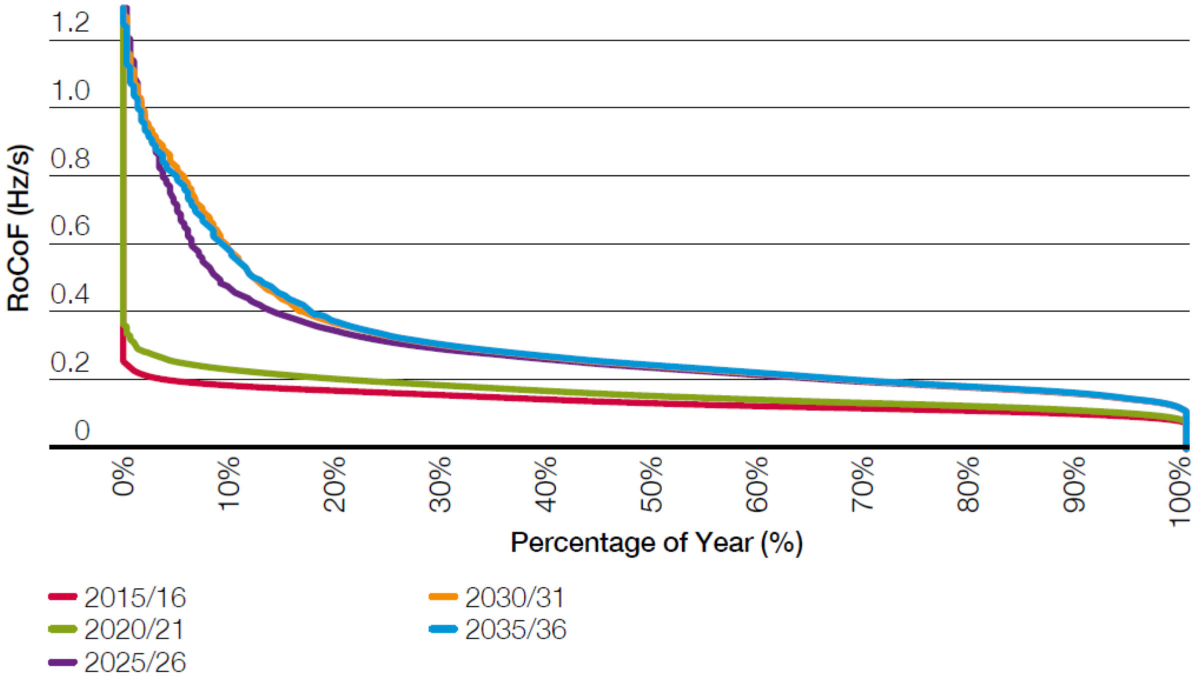
National Grid (the transmission network owner and operator in Great Britain) published the "System Operability Framework" (SOF) in 2015 [17]. This comprehensive study modelled dispatch outcomes for future energy scenarios for Great Britain, and assessed a range of potential system security challenges and solutions, including system inertia, system strength and resilience, embedded generation, and other new technologies. The various challenges identified, and the timeline over which they are anticipated to occur, are illustrated in Figure 4. High RoCoF is identified as an immediate challenge, with the highest impact upon operability of any issue considered. High RoCoF was identified to be an issue firstly due to potential tripping of RoCoF relays (loss of mains protection on embedded generation), and secondly due to the increased challenges maintaining frequency containment (preventing cascading system failure) [17].

Figure 4 - Timeline of challenges identified in the Great Britain [17]



The SOF found that system inertia would continue to decline in the Great Britain under all scenarios due to continued growth in solar PV, wind, and imports across the HVDC interconnectors. This was assessed to lead to an increasing risk of high RoCoF, as illustrated in Figure 5 (for one of the four scenarios modelled). This assessment is based upon the loss of the interconnector importing at the 1000MW limit (the largest possible contingency size). The SOF found that this maximum infeed would exceed the proposed RoCoF limit of 0.5Hz/s in the period 2025-2030 [17].

Figure 5 - RoCoF exposure in "Gone Green" future energy scenario in the Great Britain [17]



One possible mitigation option is to limit flows on the interconnector during periods of low inertia, to limit the potential RoCoF. However, National Grid notes that this is likely to be an increasingly costly and ineffective solution for long term RoCoF management, given the increasing proportion of periods of potential limit violation [17].

The SOF also modelled the potential for increased requirements for frequency reserves, considering the decreasing inertia levels. This was achieved by modelling the impact upon system frequency from the sudden loss of the largest generator. They define two categories of reserves:

1. Primary Frequency Response – delivered between 2-10 seconds following the event
2. Enhanced Frequency Response – delivered around 1 second following the event.

The modelling indicated that the primary frequency response requirement will increase by 30-40% in the next five years, and by the period 2025-2030 will be 3-4 times higher than the current level [17]. This increase was found to occur earlier in the “Gone Green” scenario due to the commissioning of new nuclear generators, which increased the size of the largest potential contingency event. The assessment indicated that in the period 2025-2030, the requirements for primary frequency response will exceed the capabilities of the generators installed, and new alternatives will be required to make up the shortfall [17]. This assumes that wind farms and nuclear plants do not provide frequency response (although they may be capable of providing these services in future). "Enhanced Frequency Response" from alternative providers was found to reduce the primary frequency response requirements.

The implementation of the new Enhanced Frequency Response service is discussed further in Section 8.3.

3.2.1 RoCoF System limit

Until recently, the operational RoCoF limit in Great Britain was 0.125 Hz/s [17], determined by the settings on loss-of-mains (anti-islanding) protection, prescribed in the grid codes[5] [40]. In 2014, the decision was made to change these codes for generators of a capacity of 5MW or greater, to those listed in Table 9 (with new standards to apply by the dates indicated) [40]. A working group is currently examining further the requirements for generators below 5MW [17].

Table 9 - New RoCoF standards applied in Great Britain for generators larger than 5 MW [40]

RoCoF Standard:	Applies to:	Transition:
1 Hz/s (over 500ms)	All non-synchronous generators (new and existing)	Existing non-synchronous generators have until 1 July 2016 to make the change. Non-synchronous generators commissioning on or after 1 July 2014 are required to commission with the new setting.
0.5 Hz/s (over 500ms)	All existing synchronous generators (and all synchronous generators commissioning before 1 July 2016).	Existing synchronous generators have until 1 July 2016 to make the change.
1 Hz/s (over 500ms)	All synchronous generators commissioning on or after 1 July 2016.	-

To reduce spurious tripping, the modification proposes that the RoCoF must "be measured to be continuously in excess of the required setting for 500ms" before activating the trip relay [40].

It is estimated that this modification will result in Balancing Services savings of £33m by 2020/21, due to the avoided costs of managing the post infeed loss RoCoF to 0.125Hz/s [40]. Against this, implementation costs for the change were estimated at £11m, consisting of the costs to change protection settings at generation sites (£10k per site, for 178 sites), the costs for synchronous generators to conduct site specific risk assessments (£25k per site, for 132

[5] Distribution Code and Engineering Recommendation G59.

sites), and the costs of implementing mitigation measures for synchronous generators (averaging £100k per site, estimated to be required at 40% of sites) [40]. Based on these costs and benefits, payback would be achieved by 2018/19.

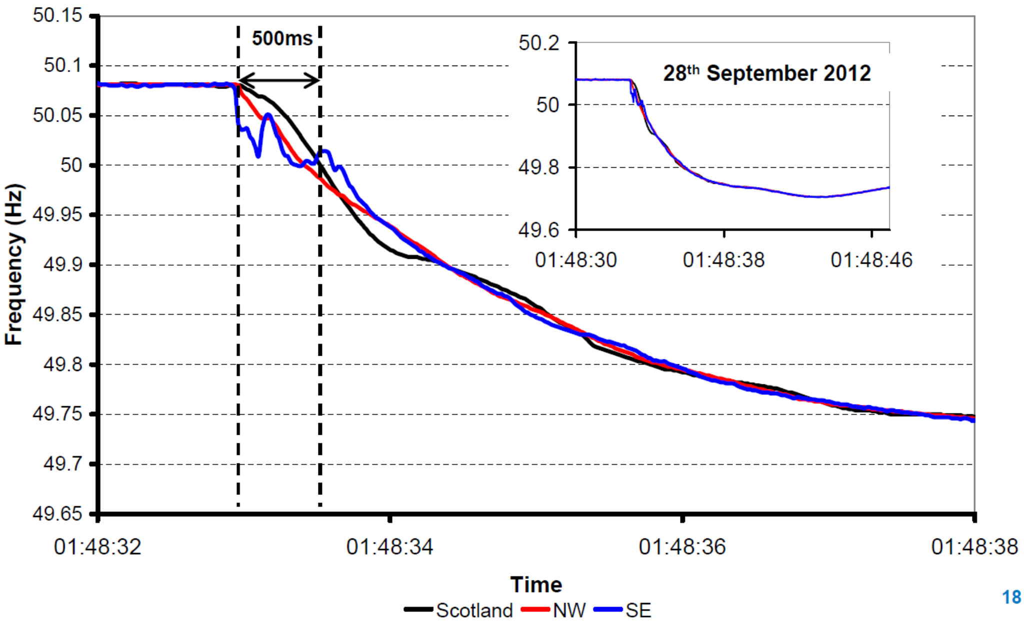
The site-specific risk assessment for synchronous generators is required due to the increased risk of out-of-phase re-closure (when a live electrical island is reconnected to the main system, and the phase angle and frequency of the waveform in the island is different to that of the main system). This poses a safety risk, if not properly assessed and addressed, and is particularly important for synchronous generators [40].

Much of the focus in Great Britain has been on understanding the behavior of embedded generation. For example, a detailed study was commissioned to conduct testing of photovoltaic inverters, to determine their ability to successfully detect an island and trip accordingly, and their ability to remain stable (and not spuriously trip) during rate of change and voltage vector shift events. All tests were found to be successful, up to the required new RoCoF level of 1Hz/s [41].

3.2.2 Measurement challenges

National Grid have also noted that a 500ms measurement window for RoCoF may be appropriate, to avoid challenges related to oscillatory behavior, and variation in local system frequency following a disturbance, as illustrated in Figure 6 [39].

Figure 6 - Frequency measured at different points in the National Grid network [39]



3.3 ENTSO-E (Europe)

ENTSO-E, the European Network of Transmission System Operators, represents 42 electricity transmission system operators (TSOs) from 35 countries across Europe, including Germany, Denmark, Ireland, Great Britain and Cyprus.

ENTSO-E drafted a "Network Code Requirements for Grid Connection" applicable to all generators, aiming to harmonize solutions and products. This was recently accepted by the European Parliament, and became a binding regulation in the EU on 17 May 2016 [42].

The ENTSO-E Network Code on Requirements for Generators states [43]:

> *"With regard to the rate of change of frequency withstand capability, a power-generating module shall be capable of staying connected to the network and operate at rates of change of frequency up to a value specified by the relevant TSO, unless disconnection was triggered by rate-of-change-of-frequency-type loss of mains protection. The relevant system operator, in coordination with the relevant TSO, shall specify this rate-of-change-of-frequency-type loss of mains protection."*

ENTSO-E originally attempted to implement a consistent standard for RoCoF at 2Hz/s, measured over a 100ms average [8]. This was revised due to concerns in respect of existing generation capability, commercial impacts on new plant and the inability of some plant to comply. This led to a devolvement of RoCoF responsibility from the ENTSO-E Network Code to the individual national frameworks where the RoCoF has yet to be defined by each TSO [8].

3.4 Nordic analysis group

The Nordic Analysis Group is a collaboration consisting of representatives from the transmission system operators:

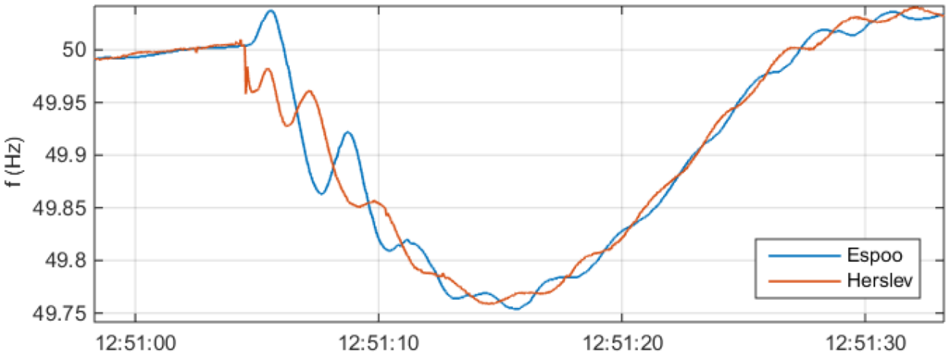
- Energinet.dk (Denmark)
- Fingrid (Finland)
- Statnett (Norway)
- Svenska kraftnät (Sweden)

In late 2013 they established the "Future System Inertia" project, approved by the Regional Group Nordic (RGN) on 19th November 2013. The project has four tasks, identified to be priority issues for the Nordic nations involved [44]:

1. Establishment of a systematic process to study frequency disturbances and inertia
2. Harmonising of inertia calculation method
3. Implementation of inertia real-time estimation
4. Study on the impact of future production and consumption changes on inertia

Like other system operators, the Nordic Group have noted that the frequency varies across the system following a disturbance, as illustrated in Figure 7. Inter-area oscillations, where generator groups oscillate against each other, are observed [44]. They note that frequency can behave very differently in different parts of the system depending on the operational scenario and fault location.

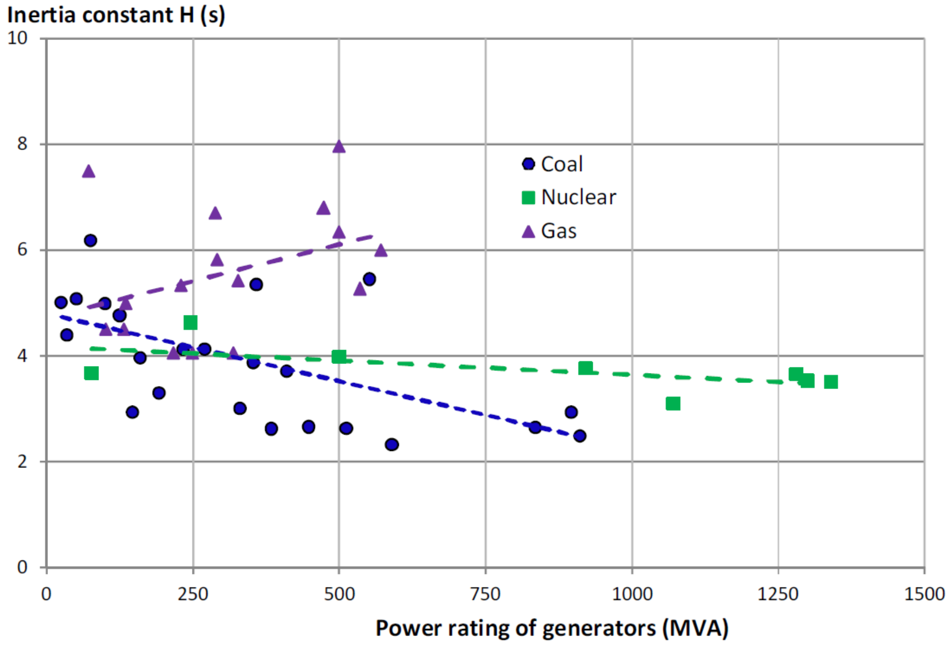
Figure 7 – Frequency measured in Espoo (Southern Finland) and Herslev (Denmark) after a loss of 580MW [44]



A significant focus of the project has been on developing methods for accurately quantifying system inertia. Synchronous inertia does vary significantly from synchronous units, and the Nordic work program suggests it may not always be straightforward to quantify.

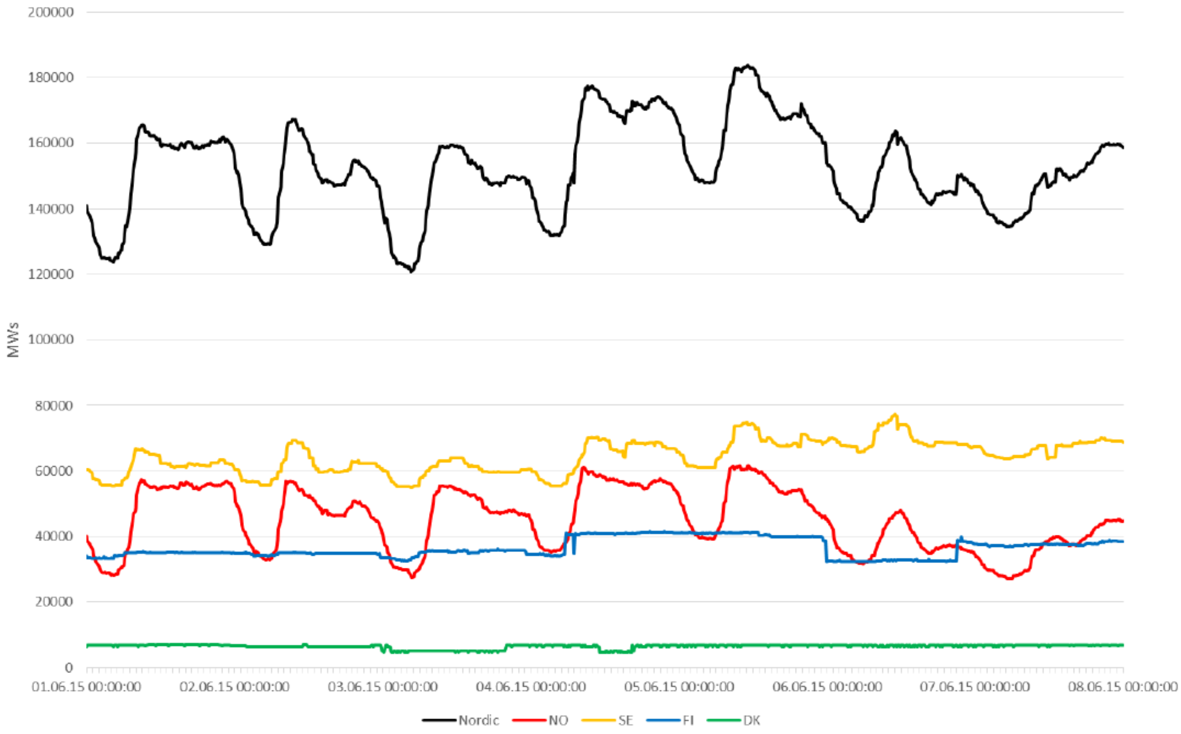
Figure 8 illustrates the variation in the inertia constants of synchronous generators of different kinds [45]. Gas generators tend to have higher inertia constants, which can lead to future carbon-constrained scenarios having *increased* synchronous inertia, due to a transition to gas-fired technology [46]. Combined cycle gas generation can have nearly twice the inertia per MW of coal [46]. Typical inertia constants (H) are 5s for gas, 3.5s for coal, and 2.1s for a synchronous condenser [45].

Figure 8 - Inertia constants for conventional units [45]



The Nordic Group are also exploring the implementation of real-time tools to calculate and monitor system inertia [44]. The Nordic system operators now monitor and exchange inertia data in real-time; an example is illustrated in Figure 9. The lowest synchronous inertia measured in Sweden, Finland and Norway was 115 GWs (in 2009) [44]. They estimate inertia values in 2020 between 124 GWs and 305 GWs [44]. Note that this remains several orders of magnitude larger than in the South Australian region, which now has inertia below 2,000 MWs in some periods.

Figure 9 - Synchronous inertia (kinetic energy) in the Nordic system in week 23, 2015 [44]



The Nordic Group have now commenced a Phase 2 project, to further address several issues raised in the first report, including anticipating avoiding the effects of low-inertia situations, by means of proper forecasting tools and mitigation measures. This project started on 8 June 2016 and will run until the end of June 2017.

It would appear from this work program that the issue of inertia and RoCoF management is not an urgent issue in the Nordic region, and the focus is primarily on monitoring.

3.5 New Zealand

Transpower is the system operator in New Zealand. They currently do not have a grid code requirement for generators in relation to RoCoF [10].

In 2011 an event occurred on the system on the North Island of New Zealand that caused the frequency to drop to a nadir of 47.5 Hz. The initial RoCoF for the event was 0.73 Hz/s[6] and there was no evidence of units tripping from the system as a result of this RoCoF [10].

A new Automatic Under Frequency Load Shedding (AUFLS) scheme has been proposed for the North Island. This new scheme is designed to disconnect four blocks of demand

[6] No information was given for the time period used to calculate the RoCoF value for this event.

sequentially, with block 4 employing a RoCoF relay to allow acceleration of load shedding if the RoCoF exceeds 1.2 Hz/s [47].

Transpower published a report in 2014 which examined the effect of wind generation on the overall inertia of the New Zealand grid [47]. The baseline power system frequency response showed RoCoF levels in the range 0.12 Hz/s to 1.7 Hz/s (at 1 second after the contingency), depending upon the snapshot (winter peak, summer peak or summer trough), the nature of the contingency event, and whether it was measured on the North or South Island. Increasing the amount of wind generation was found to increase RoCoF levels to as high as 2.1Hz/s (with the replacement of 1289 MW of synchronous plant by wind generation). At this time, New Zealand does not appear to have established a work program to explore this further.

3.6 Hawaii

Hawaii does not have a Grid Code standard for rate of change of frequency [10].

Hawaii has experienced several high RoCoF events which have resulted in units tripping from the system. Gas units in Hawaii were found to trip for RoCoFs in excess of 0.3 Hz/s [10], as outlined in Table 8. The RoCoF was found to cause the over temperature protection to trip if the proportional droop response was too fast for the temperature control.

Table 10 - Historical high RoCoF events in Hawaii [10]

Date	Frequency nadir (Hz)	RoCoF (Hz/s)	Notes
Feb 2010	58.7	0.307	No further generation tripped for this event.
Jul 2010	57.7	0.373	Resulted in cascade tripping of gas turbine units. Following the event, the controllers of the gas turbines were tuned and a position limiter was inserted for the fuel valve of each unit.

Steam units in Hawaii were not found to experience difficulties with these RoCoF events, but it was envisaged that a sustained change in frequency could cause problems for steam units. There was no evidence that these events resulted in significant mechanical issues for the units [10].

3.7 Cyprus

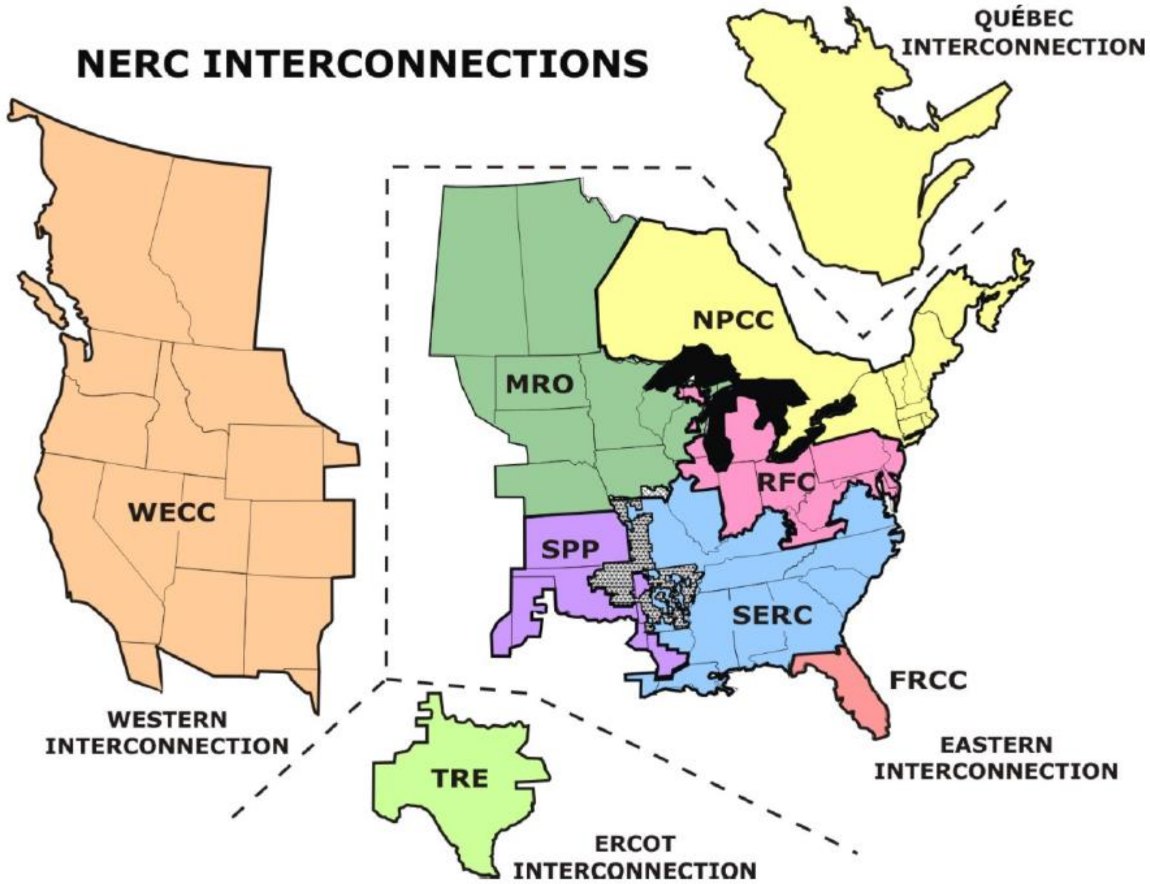
Cyprus is an island system with a peak demand of ~1 GW. There are no connections between the island of Cyprus and the mainland.

Cyprus experienced a high RoCoF event in January 2012, which resulted in a RoCoF of 1.3 Hz/s (measured over 500ms). There was no loss of conventional generation during the event, but the high RoCoF caused 68 MW of wind generation to disconnect from the system [10]. This was because the protection schemes employed by the wind farms caused the wind farms to disconnect for RoCoFs in excess of 1.25Hz/s. The settings of the anti-islanding protection at these wind farms has now been increased to 1.5Hz/s [10].

3.8 North America

The National Renewable Energy Laboratory (NREL) commissioned GE Energy Management to conduct detailed modelling of the frequency response and transient stability implications of a 33% wind and solar scenario for the USA Western Interconnection [2]. As illustrated in Figure 10, the Western Interconnection spans a large geographic area, and supplies electricity to a large proportion of the USA. Each interconnection illustrated represents a large, synchronously connected grid.

Figure 10 - North American electricity grid interconnections [2]



The study notes there is general concern among power system operators and utilities in the USA regarding the degradation of frequency response over the past two decades. The degradation is due to various factors, including the withdrawal of governor responses shortly after an event, the lack of in-service governors on conventional generation, and the unknown and changing nature of load frequency characteristics [2]. High penetrations of non-synchronous generation further complicate this issue.

Dynamic power system modelling was conducted with GE's proprietary PSLF model, across a wide range of scenarios. The modelling showed that the initial RoCoF increased by 18% in scenarios with an increased renewable penetration level (due to reduced system inertia). However, the levels of RoCoF observed were on the order of 0.1Hz/s in all cases considered (the base case had an initial RoCoF of 0.096Hz/s, and the high renewable case had an initial RoCoF of 0.113Hz/s, or as high as 0.118Hz/s in the most extreme sensitivity explored) [2]. Furthermore, the Western Interconnection (and the USA more broadly) does not rely upon RoCoF-based protection, meaning that the increased RoCoF was assessed to be of limited system-wide consequence. These very small levels of RoCoF are related to the large synchronously connected network in the Western Interconnection, which maintains significant levels of synchronous inertia, even in high renewable penetration cases.

The NREL study also noted that no commercially available wind or utility-scale photovoltaic generation is capable of operation in a system without the stabilizing benefit of synchronous machines [2]. The modelling considered the conversion of some retiring coal plants to synchronous condensers, and found that this was effective for stabilizing the system [2].

Similar modelling for the California ISO (CAISO) explored a snapshot with wind and solar generation providing 37-50% of California's generation (11-15GW), and modelled the loss of two units at the Palo Verde Nuclear Power station (a 2690 MW event) [48]. The entire Western Interconnection was modelled, including the additional of wind generation such that it represented 15% of the rest-of-WECC generation. The study found some minor impacts upon RoCoF levels, but that RoCoF was not a significant challenge for CAISO at these levels [48].

Similarly, ERCOT (the Electricity Reliability Council of Texas) notes a maximum RoCoF of only 0.2Hz/s (during high wind conditions in 2013) [3]. Projecting forward, their studies (based upon 2012 system conditions) indicated that RoCoF as high as 0.4Hz/s could occur for the two largest unit trip of 2750MW, as per the required NERC standard [3]. This remains far below the levels of relevance in the NEM.

These results suggest that jurisdictions in North America do not provide a useful analogue for the NEM with regards to RoCoF. The same likely applies for most USA jurisdictions, which operate as parts of large, synchronously connected systems.

3.9 Germany

In 2015, Germany sourced 32.6% of electricity from renewables, and is one of the top countries in the world for total non-hydro installed renewable capacity (92GW), and renewable capacity per inhabitant [49]. Germany is leading in renewable integration in many respects, and provides valuable insights for other jurisdictions aiming to meet higher renewable proportions. However, this review did not identify any important studies or key insights from Germany relating to management of high RoCoF. Germany has a relatively large electricity demand, and is highly interconnected to neighboring power systems with AC interconnectors. This means that Germany is not likely to encounter high RoCoF challenges until a considerably higher proportion of non-synchronous generation is achieved.

3.10 Denmark

In 2015, Denmark sourced 42% of electricity from wind generation, and is among the world's top 20 countries for non-hydro renewable power capacity per inhabitant [49].

In 2013, Energinet.dk in Denmark purchased two 200 MVA synchronous condensers to support the power system, at a cost of 340m DKK [50] (~A$68m) [51]. Synchronous condensers provide a range of system services, including synchronous inertia. However, it is likely that these units were primarily installed to address system strength and other relatively localized grid support issues, rather than synchronous inertia and RoCoF challenges. Like Germany, Denmark is highly interconnected with neighboring regions via AC interconnectors, and therefore has access to considerable amounts of synchronous inertia from other jurisdictions. This review did not identify any key insights or significant studies relating to high RoCoF in Denmark.

Denmark requires new generators connecting to be able to withstand a RoCoF of ±2.5Hz/s (increased from a previous value of 2 Hz/s) [24]. The Energinet.dk regulations for grid connection state for thermal power stations larger than 1.5 MW [52]:

> *"The general purpose of the following requirements is to ensure that the power station unit is designed in such a way that it can continue to operate at transient frequency deviations. These deviations normally occur in connection with grid faults. A power station unit must be able to withstand transient frequency gradients (df/dt) of up to ±2.5 Hz/s in the connecting point without disconnecting."*

The time interval over which the RoCoF is measured is not mentioned (for thermal power stations).

For wind and PV generation above 11kW, the regulations state that generators must be able to withstand a change of frequency (df/dt) of ±2.5Hz/s, with a trip time of 200ms [53, 54].

3.11 South Africa

The South African Grid Code for "Renewable Power Plants" (RPPs) requires [55]:

> *"The RPP shall remain connected to the NIPS[7] during rate of change of frequency of values up to and including 1.5 Hz per second, provided the network frequency is still within the minimum operating range."*

South Africa has a large, predominantly coal, nuclear and hydro based system experiencing relatively high demand growth. The synchronous inertia of the system is therefore unlikely to be reduced significantly by the development of renewable generation in the short term [8].

3.12 Conclusions

This review found very few large international jurisdictions (500 MW or more) that are experiencing issues related to high RoCoF. EirGrid/SONI (Ireland/Northern Ireland), and National Grid (Great Britain) are notable exceptions; both have identified emerging concerns about high RoCoF levels (>0.5 Hz/s), and have established work programs to address the specific challenges facing their systems. These work programs are especially relevant to the NEM, and some specific findings from an examination of these work programs are outlined below.

Smaller island grids (such as Cyprus and Hawaii) have also experienced high RoCoF events. However, these systems are less relevant to the NEM for a number of reasons. Firstly, as very small systems they do not have significant markets, and therefore do not offer insights on market implementation. Secondly, although there may be lessons from the demonstration of a range of technical solutions in these systems, scaling these up to the scale of the NEM may not be commercially optimal. For example, Hawaii makes extensive use of batteries for managing wind and photovoltaic variability, but a similar approach may not be optimal at the scale of the NEM due to the cost involved in scaling up the battery systems, and the availability of a broader range of technical options in a larger system.

Large, highly interconnected systems (such as Germany, Denmark, the Eastern and Western Interconnections in the USA, and Texas) have orders of magnitude more synchronous inertia than these examples, and are therefore unlikely to encounter issues related to RoCoF until they reach *significantly* higher renewable penetration levels (far beyond the levels being studied at present). For example, a study of the Western Interconnection in the USA with a 33% wind and solar scenario simulated a RoCoF of 0.118 Hz/s in the most extreme sensitivity explored [2]. The low RoCoF value calculated is due to the very large scale of the

[7] NIPS refers to "National Interconnected Power Systems".

Western Interconnection, and the comparatively smaller size of the contingency event modelled (a trip of two fully loaded nuclear power station units for a loss of 2,750 MW, representing around 2% of the system size). Similarly, ERCOT (Texas) has experienced a maximum RoCoF of 0.2 Hz/s, and projects that 0.4 Hz/s may be possible in future [3]. These levels of RoCoF remain an order of magnitude below those now possible in South Australia [1].

The specific findings of this review relating to international experiences with high RoCoF are outlined below.

3.12.1 Insights for the NEM

3.12.1.1 RoCoF Access Standards

There may be justification for initiating a review of the NEM Access Standards relating to RoCoF. The present Access Standards for RoCoF in the NEM are summarized in Table 1.

Table 11 - RoCoF access standards in the NEM [4]

	Requirement defined in the NER
Minimum Access Standard	±1 Hz/s for 1 second
Automatic Access Standard	±4 Hz/s for 250 ms

Firstly, modelling conducted by DNV-GL (for EirGrid/SONI) suggests that the RoCoF withstand capabilities of synchronous generators are highly dependent upon the duration of time that they are exposed. For example, a 260 MW CCGT dual-shaft machine was found to remain stable under RoCoF of -2.2 Hz/s for 250 ms (under the operation conditions of 100% load and a power factor of 1 unity), but was not stable at -1 Hz/s for 1 second [5]. This suggests that the NEM Automatic Access Standard (4 Hz/s for 250 ms) could actually be *less* onerous than the Minimum Access Standard (1 Hz/s for 1 second) in some cases. This may mean that a generator could be allowed to connect based upon the Automatic Access Standard, but not be able to meet the Minimum Access Standard. This could be investigated with modelling, and possibly unit testing. It may be prudent to change the Automatic Access Standard so that it specifies a need to also withstand 1 Hz/s for 1 second.

Secondly, EirGrid/SONI's experience highlights that the subtleties in how the measurement window is defined have consequences for withstand capabilities. They have selected a measurement window of 500 ms, measured as a rolling window. However, DNV-GL's modelling found that the RoCoF withstand capabilities of synchronous generators are highly sensitive to the total duration of the RoCoF event. Their modelling showed that most generators could achieve compliance with a 1 Hz/s standard over an *absolute time window of 500 ms*. However, the capabilities of generators were much lower when the 1 Hz/s RoCoF was sustained over a full second (for a 1 Hz absolute drop) [5]. This means that meeting the 500 ms rolling window standard could pose challenges for synchronous generators in the EirGrid system, even where DNV-GL's modelling indicated that the units were stable at 1 Hz/s for 500 ms [6]. For the purposes of generator testing, EirGrid has defined representative frequency traces that should be withstood; this may offer a suitable approach.

It may also be prudent to explore the potential for implementing a more stringent Minimum Access Standard. EirGrid/SONI have faced considerable challenges in attempting to increase their system-wide RoCoF standard from 0.5 Hz/s to 1 Hz/s (over a 500 ms rolling window). Demonstrating compliance with a stringent standard is far more straightforward for new connections, when the original equipment manufacturer (OEM) is already heavily involved. EirGrid/SONI have discovered that the process of demonstrating RoCoF compliance for incumbents is far more complicated and costly.

It is clear that the NEM power system is trending towards lower levels of synchronous inertia, meaning that there are significant advantages in targeting a future power system with higher RoCoF withstand capabilities. This process needs to commence early, to ensure that generation installed now (which is likely to remain operating in 10-30 years) has demonstrated the capabilities to confidently operate in the future high-RoCoF regime.

This suggests that the minimum access standards for RoCoF should be set at the highest possible level that does not constitute a barrier to entry, and does not substantially increase costs for new entrants. Other jurisdictions (such as Denmark) have access standards as high as 2.5 Hz/s (over 200 ms), suggesting that standards around this level may be achievable, and may not present a significant barrier to entry. RoCoF standards applying in other jurisdictions are summarized in Table 2.

Table 12 – RoCoF Standards applied in other jurisdictions

	RoCoF Standard
Ireland (EirGrid/SONI)	0.5 Hz/s, changing to 1 Hz/s (over a 500ms rolling window)
Great Britain (National Grid)	0.125 Hz/s, changed recently to 0.5 Hz/s for incumbent synchronous units, and 1 Hz/s for non-synchronous units and new synchronous units (over 500 ms)
Denmark	2.5 Hz/s (over 200 ms for wind & PV, no specified timeframe for synchronous)
New Zealand	Does not have a standard for RoCoF
Hawaii	Does not have a standard for RoCoF

Spain	2 Hz/s [7, 8]
South Africa	1.5 Hz/s (applying only to renewable power plants) [8, 9]

Determining the RoCoF capabilities for the range of potential new entrants requires careful consideration. This is particularly pertinent for gas-fired generation, which this review indicates could be more sensitive to RoCoF than inverter-connected generation, and which could be an important new entrant in the NEM (particularly for peaking capacity). The likely RoCoF capabilities of other types of synchronous generators should also be considered carefully, including solar thermal, biomass and geothermal. This process will need to involve manufacturers; AEMO could consider initiating a work package to interview manufacturers, and determine the maximum RoCoF levels for which they are prepared to endorse their products.

EirGrid/SONI's high-level analysis shows signs of instability (and potential for pole slipping) for incumbent synchronous units at around 1 - 1.5 Hz/s. This modeling is not conclusive, however, and it may be possible to design new units with higher RoCoF withstand capabilities. Analysis of historical international high RoCoF events suggests there is no evidence of significant mechanical damage for synchronous units due to high levels of RoCoF. And, there is no evidence of generators tripping directly due to high levels of RoCoF [10]. In some cases units have been observed to trip due to various control and instrumentation issues [10]. In these cases it was possible to address the identified issues by adjusting the relevant control and protection systems. However, the availability of data from historical events is limited, and is insufficient to draw strong conclusions.

3.12.1.2 Generator testing for RoCoF withstand capabilities

EirGrid/SONI's experience show the significant amount of time involved in testing of generators to determine RoCoF withstand capabilities. The individual unit testing required is complex, non-routine, and requires engagement of specialist expertise at the relevant OEMs.

Given the uncertainty over the RoCoF withstand capabilities of most generators in the NEM, the trends towards higher RoCoF exposure, and the likely expense involved in mitigating high RoCoF exposure, it would be beneficial to rigorously establish the RoCoF withstand capabilities of generators in the NEM. EirGrid/SONI's high-level analysis indicates signs of instability (and potential for pole slipping) for synchronous units at around 1 - 1.5 Hz/s. This is within the RoCoF exposure levels in South Australia at present [1].

For these reasons, the NEM could consider commencing a program of work to establish the RoCoF withstand capabilities of individual units. Given resource constraints and the very limited number of specialists with the required expertise at OEMs, this should be carefully planned, probably targeting the highest capacity factor units in SA first.

EirGrid's program of work focuses on each unit demonstrating the ability to comply with their proposed 1 Hz/s standard. EirGrid's analysis suggests that testing will need to consider a wide range of aspects for each generating plant, including:

- ***Mechanical integrity*** – transient torques on machine shafts and turbine blades, including the potential for pole slipping in synchronous units,
- ***Protection*** – The potential for misoperation of plant protection systems under conditions of extreme RoCoF,
- ***Control Systems*** – The potential for unintended consequences related to plant control systems, under conditions of extreme RoCoF,
- ***Unit specific factors*** - Flame stability or over-temperature in gas turbines (GT)s, and hydraulic transients in hydro plant, and
- ***Auxiliaries*** – Impact on auxiliary plant such as motors (e.g. boiler feed pumps, gas compressors).

The studies required to robustly demonstrate RoCoF withstand capabilities are likely to be costly; GE estimated the associated costs of testing to be around US $1.5 M per CCGT [11, 8], while another source estimated similar costs at around of €900 k per plant [8]. Careful consideration will need to be given as to who will be responsible for paying these costs, and how they will be recovered. In Ireland, generators have been responsible for bearing the costs of demonstrating compliance with the proposed new standard, without the ability to recover these costs.

3.12.1.3 Anti-islanding protection for embedded generation

In some jurisdictions (such as Ireland and Great Britain), anti-islanding protection is based upon the detection of RoCoF, and can therefore trigger during extreme RoCoF events (when it is not desired). Even where anti-islanding protection is not based upon RoCoF directly, other types of protection may misoperate under conditions of extreme RoCoF. Given the increasing prevalence of distributed PV (and the large potential contingency size that could result from their tripping), it will be important to establish the level of RoCoF that can be tolerated by anti-islanding protection in the distribution network in the relevant parts of the NEM. Both Ireland and Great Britain have been conducting an extensive program of work to adjust anti-islanding protection settings, to withstand a higher level of RoCoF.

3.12.1.4 Collaboration with EirGrid/SONI on high RoCoF issues

EirGrid/SONI are the most advanced internationally on exploring RoCoF related issues. Their comprehensive work program (since 2010) provides many valuable insights for the NEM. Their ongoing work in this area should continue to be highly relevant and valuable. AEMO could explore the potential for a collaborative relationship with EirGrid/SONI, to share lessons learned and combine efforts in this challenging and groundbreaking field.

4 FAST FREQUENCY RESPONSE TO MITIGATE HIGH ROCOF

This section reviews international investigations into emerging technology solutions for managing high RoCoF, with a particular focus on analysis exploring the use of a "Fast Frequency Response" (FFR). Definitions vary, but for the purposes of this report, "Fast Frequency Response" is defined as a rapid injection of active power (in a time period of 1-2 seconds or less), to arrest the frequency decline following a contingency event.

Later sections review the practical demonstration of some possible technologies that could provide FFR, including storage (section 5), demand response (section 6) and emulated inertia from wind turbines (section 0). This section focuses on higher level insights around the implementation of such a service, from a more technology neutral perspective.

4.1 EirGrid/SONI (Ireland/Northern Ireland)

As the third strand of the program of work to approve and implement the new RoCoF standard in Ireland and Northern Ireland, the CER and UR required exploration of "alternative solutions". This is based upon a recognition that demonstrating compliance with the new RoCoF standard could take considerable time, and may inhibit achievement of the stated renewable energy goals. Therefore, the "Alternative Solutions Project" aims to investigate alternative (or complementary) solutions for managing high RoCoF. It is worth noting that EirGrid/SONI believe that generator compliance with the proposed new RoCoF standard is the most efficient and timely solution, and therefore state that their primary priority is to deliver the RoCoF Generator project and DSO project [26, 56]. They view the Alternative Solutions project as potentially complementary to the implementation of the wider DS3 Program [56].

The investigation of alternative solutions has progressed over two phases. In the first phase, EirGrid/SONI commissioned DNV-GL to identify potential "alternative or complementary technology solutions" to changing the RoCoF standard from 0.5Hz/s to 1Hz/s. A range of theoretical options were assessed at a high level, as listed in Table 14. In the second phase, more detailed power system modelling was conducted to assess the nature of the fast frequency response required from these technologies to mitigate high RoCoF.

4.1.1 Distinguishing between synchronous and non-synchronous technologies

The Phase 1 review makes a distinction between two fundamentally different technology types, which have the potential to assist with mitigating high RoCoF:

1. ***Synchronous technologies,*** which provide an inherent inertial response
2. ***Non-synchronous technologies***, connected to the system via power electronics (inverters). These were termed "Fast Frequency Response" (FFR) type devices [57]. This category includes "synthetic/emulated inertia" type devices.

The review found that synchronous and non-synchronous technologies have fundamentally different characteristics in the nature of their response to high RoCoF events [56]. Importantly, for synchronous technologies, the response time is immediate, while for non-synchronous technologies, there is a delay between the RoCoF event and the response.

Although both technology types were found to have the capability to help with mitigating high RoCoF events, synchronous technologies were found to be the most proven technology [26]. Non-synchronous devices may have the potential to provide responses that would mitigate high RoCoF events, but are less proven. In particular, the review found that the RoCoF detection methodology and response time would need to be explored further and resolved prior to implementation [26].

Several of the synchronous options considered in the DNV-GL study are listed in Table 13. Non-synchronous options are discussed further below.

Table 13 – Synchronous technologies for RoCoF mitigation considered in DNV-GL study [40]

Synchronous Devices	Notes
Synchronous compensators/condensers	Generators that are synchronized with the transmission network, and operate as free spinning motors. Not mechanically driven by a prime-mover, nor do they drive any load. Can be retrofitted at decommissioned power plant generators, where the prime-mover is decoupled from the generator.
Rotating stabilizers	Similar in nature to a synchronous compensator; provides synchronous inertia.

4.1.2 Response time of FFR-type devices

DNV-GL characterized the response time of a FFR-type device as being composed of the following four components [57]:

1. ***Measurement time*** – the time needed to detect and measure the severity of a RoCoF event

2. ***Signaling time*** – the time required to get the activation signal from the detection and measurement system to the FFR-type device. The delay typically depends upon the communication system used, and the distance to the FFR-type device.
3. ***Activation time*** – the time required for the FFR-type device to deliver the initial power response from the moment it receives the activation signal
4. ***Ramping time*** – the time required to ramp up to the required active power response from the device, once the activation signal has been received.

The total response time of the device will be the sum of each of these four components, with each discussed further below.

4.1.3 Measurement Time

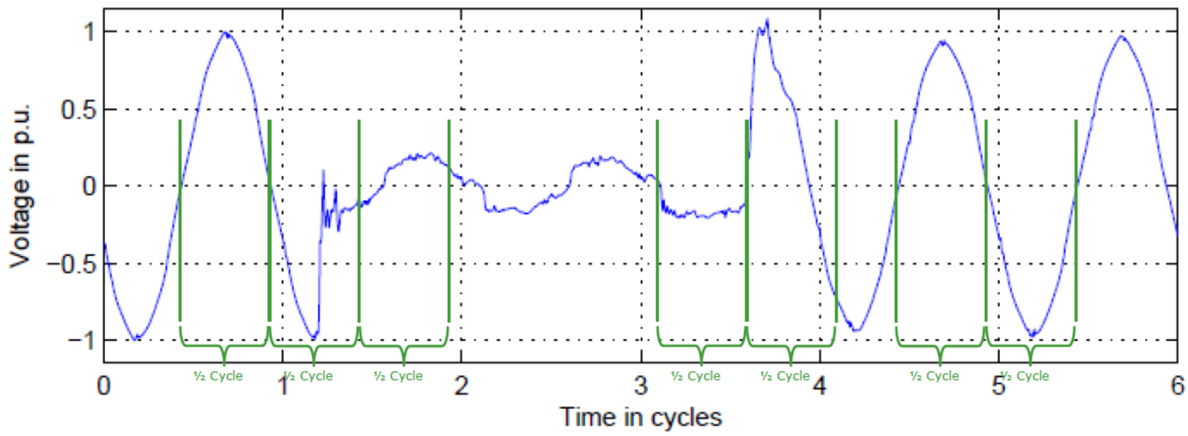
The time period required to reliably activate a (synthetic/emulated) FFR-type device for the delivery of an effective power response was found to pose some challenges. Within the total response time of the device, the most challenging aspect was found to be the period required to reliably detect and measure a RoCoF event to ensure the appropriate response to mitigate the event [57]. At present, RoCoF detection is mostly used for the purposes of anti-islanding disconnection protection, but there is no proven track record for accurate RoCoF detection for the purpose of mitigation of RoCoF events [57].

RoCoF and frequency measurement devices measure the voltage waveform. There are several methods for calculating the system frequency. One method is to calculate the time between zero crossings of the voltage, with the period of the sine wave then translated into a frequency. A low pass filter is used to eliminate high frequency transient voltage signals [57]. Using this method, for each half cycle a duration measurement can be performed. With this technique, only complete sine waves should be used for measurement, because of possible asymmetry of the voltage waveform [57]. For reference, with a 50Hz grid frequency in the NEM, a full cycle is completed in 20ms.

Another technique that can be used for frequency measurement is Fast Fourier Transform Analysis (FFTA). This method determines the frequency based upon Fourier analyses, which makes it possible to use only a part of the voltage sine wave, and provide a potentially faster (more continuous) measurement. However, transient signals and distortions of the sine wave often occur following significant disturbances (as illustrated in Figure 11), which means that measuring only a part of the sine wave may not give a good indication of the actual change in frequency [57]. FFTA methods are only accurate if the voltage waveform is not distorted, and for this reason, measurement techniques like FFTA may not provide better reliability for RoCoF detection than those based upon zero crossings [58].

For example, system faults (short circuits) cause transients in the sine wave of the system voltage. Zero crossings of the voltage will shift, even when the system frequency (based upon the speed of the generators supplying the grid) does not change. Switching operations can also cause a sudden phase shift of the voltage at the moment of switching [57]. This is illustrated in Figure 11, which shows an example of transients in the sine wave as a result of a network fault in the power system. This figure shows both a voltage dip, and a frequency shift. As a result of these effects, the time between zero crossings may be longer or shorter, and the calculated frequency therefore lower or higher than the actually system frequency. The RoCoF device must remain stable under these circumstances, and not false-trigger [57].

Figure 11 - Voltage dip and temporary phase shift in zero crossings [59]



They indicate several methods for reducing false triggering of RoCoF devices [57]:

1. ***Measure over a longer duration of time*** – Allow a longer period for the frequency measurement and calculation, so that multiple sine waves can be sampled. Typical measuring windows are 2-100 cycles (40ms to 2 seconds).
2. ***Introduce time delays*** – Employ a time delay to reduce the effect of possible transients in the signal. Typical time delays are 50-500ms.
3. ***Block triggering when voltage is reduced*** - Block the RoCoF trip signal when the grid voltage is temporarily reduced. This prevents nuisance tripping during short circuit transients.
4. ***Block triggering for an unexpectedly high RoCoF*** – The maximum expected RoCoF can be determined for a system based on system inertia, and the largest possible

contingency size. RoCoF devices can be blocked for activation when the measured frequency change is larger than the expected maximum.

Oscillatory phenomenon can also cause challenges for accurate measurement of system frequency. Synchronous generators respond to a large frequency excursion by providing an initial inertial response, followed by primary governor control action. These local control actions can result in damped frequency swings in the early stages following an event, as illustrated in Figure 2. Studies performed by EirGrid/SONI suggest that a timeframe of 500ms is appropriate for these initial frequency swings to dampen, and for the system to reach "coherency" [23, 57].

For Loss of Mains protection relays, best performance has been found to be achieved by incorporating a delay time, to increase stability in the presence of small scale system transients. A 500ms timeframe has been indicated as appropriate to reliably calculate RoCoF [60, 61].

4.1.4 Signaling time

The delays involved in signaling typically depend upon the communication system used, and the distance to the FFR-type device. It is possible to send control signals in micro-seconds if need be, but delays may occur if controllers are remote from the site, or if the signals need to be sent to a number of devices.

4.1.5 Activation time

The activation time partly depends upon the power electronic converters used, and partly by the FFR-type device behind the power electronic converter. Power electronic converters are generally fast compared with the grid frequency, with the limiting factor potentially being the ramp-rate of the FFR-type device.

4.1.6 Ramping time

The ramping time depends upon the nature of the FFR-type device. A selection of the devices considered are listed in Table 14.

Table 14 – Non-synchronous technologies for RoCoF mitigation considered in DNV-GL study [40]

Non-Synchronous Devices	Notes
Batteries	Battery power is instantly available from the terminals, and therefore the power converter is the main limitation for energy delivery.

(Flow, Lead Acid, Li-ion, Nickel, Sodium-Sulfur)	The rapid energy *consumption* capability is generally much lower in capacity, and therefore the technology is better suited to prevent low frequency RoCoF events.
Flywheels	Can deliver large amounts of energy, for relatively short durations (<1min to 1hr). Flywheels are connected to the grid through power electronics, and therefore can only deliver emulated inertia (not synchronous inertia).
Wind turbines	Older turbine types (1 & 2) were capable of providing some synchronous inertia, but newer types (4) are connected via a full converter, and can only contribute FFR-type response (no synchronous inertia).
Demand side management (DSM)	DNV-GL was of the opinion that DSM remains insufficiently proven for RoCoF mitigation. The identified challenges with sufficient aggregated capacity, detection technology, novel communications nd new TSO operational controls.
HVDC interconnectors	Capable of providing a large variety of system services, depending upon the converter technology employed.

EirGrid/SONI received comments on their Phase 1 report stating that type 3 wind turbines (doubly-fed induction generator (DFIG) type) can provide a limited inertial response to the system, when configured in a certain manner. For example, a DFIG that has its rotor winding short-circuited will act like a traditional induction machine [56]. Similarly, a DFIG with a DC current inducted on its rotor windings will act similar to a synchronous machine [56]. Both of these configurations would allow for an inertial contribution to the system. However, the power electronic converter on the rotor is usually controlled such that the speed of the machine will optimize the power take-off of the wind turbine [56]. Studies have illustrated that this type of rotor configuration restricts the machine from giving an inertial response to the system [62]. DFIGs currently deployed in Ireland are operated in this manner, but could possibly be modified to provide inertial response [56]. DNV-GL suggests that the converter control in DFIG type turbines delivers constant torque control at a high bandwidth, which means that any synchronous inertia is very transient, and rapidly negated by the torque control loop. This means that the synchronous inertial response from Type 3 turbines may be limited [57]. In any case, most new wind turbine installations at present are Type 4, which are connected to the system via power electronics, and are therefore only capable of providing "emulated" inertia responses [57].

4.1.7 Summary of findings on device response times

The DNV-GL analysis concluded that the total response time of FFR-type devices is an obstacle for providing effective "emulated" inertia, with the most challenging aspect being the period required to robustly detect a RoCoF event [57].

With relay protection technology commonly used at present, 30ms is necessary to detect frequency changes. However, *accurate* detection requires a longer duration, likely closer to 500ms. To prevent RoCoF of 1Hz/s (measured over 500ms), the reliable response time needs to be much shorter than 500ms. This barrier will need to be overcome for FFR-type devices to provide a helpful contribution to mitigating high RoCoF [57].

DNV-GL recommended that various aspects are studied further, including measurement methodologies, and the likely electricity network characteristics with regards to damped frequency swing durations [57].

Until these issues can be addressed, DNV-GL concluded that synchronous solutions are likely to continue to be required to mitigate high RoCoF [57].

4.1.8 Power system modelling of FFR devices

Phase 2 of the EirGrid/SONI "Alternative & Complementary Solutions Project" involved detailed power system modelling to explore the potential contributions of FFR-type devices (providing "emulated inertia") for mitigating high RoCoF [30]. The study is framed with the specific objective of exploring the additional system services that would be required as an *alternative* to increasing the RoCoF standard from 0.5Hz/s to 1Hz/s. The study analyses the year 2020 with the anticipated increased non-synchronous generation, and allowing a SNSP (System Non-Synchronous Penetration) of up to 75%. Two types of system services are explored: Synchronous inertia, and FFR (and combinations of the two). The modelling calculates the additional quantities of each required to decrease RoCoF from 1Hz/s to 0.5Hz/s.

Key findings are as follows [30]:

- A system inertia of 20,000 MW.s is required for the majority of dispatches to maintain potential RoCoF within 0.5Hz/s. This equates to approximately 12,000 MW.s of supplementary synchronous inertia added to the 1Hz/s base case, to limit RoCoF to 0.5Hz/s.
- The performance of FFR devices was found to be highly sensitive to the characteristics of the response. In particular, the device response time and ramp rate were of significant importance. In order to meet the RoCoF criteria, the FFR devices would need to:
    - Begin responding within 100ms from the start of the event

- Ramp to full active power injection within 200ms after the device begins to respond (a ramp rate in the realm of 1500MW/s, in these simulations)
- Implement a suitable form of control to prevent unintended adverse system issues during the frequency recovery
- Provide a total of ±360MW for the duration of the event
- Be able to respond to both high and low frequency events

The modelling explores in some depth a range of potential triggering and control methods for the FFR-devices. The results show [30]:

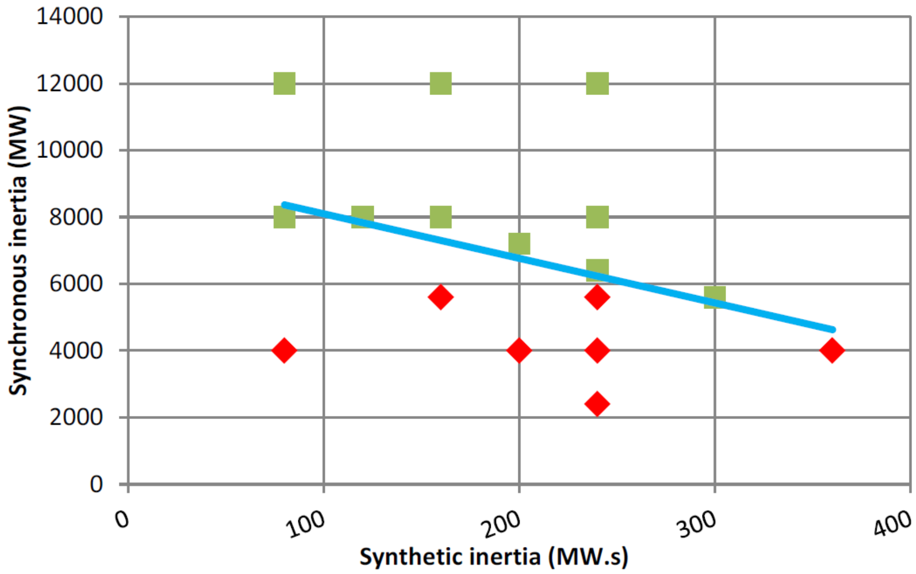
- An uncontrolled, static provision of emulated inertial response leads to over-provision of active power following small frequency excursions, potentially leading to violation of RoCoF during frequency recovery. This method is therefore considered unsuitable.
- A RoCoF controlled response is also unsuitable; delays in measurement mean that this approach cannot respond sufficiently rapidly.
- A droop controlled emulated inertial response was found to be appropriate, but only if an aggressive droop of approximately 0.25% was applied (the standard droop setting of 4% was insufficient).
- An initial frequency triggered active power injection response, followed by a transition to a droop controlled response (upon sensing system frequency beginning to recover), was found to be successful in simulations.

Based upon these simulations, the study recommended a controlled recovery. A droop controlled response in the frequency recovery period appeared to offer a suitable response [30]. However, a large penetration of devices with different droop characteristics may have system stability implications, which would need to be explored [37]. Responses to the report suggested exploration of alternative control strategies, such as a simple continuous and proportional controller, using frequency and RoCoF measures as input variables [37].

The modelling also found that the composition of the load became increasingly important at low levels of synchronous inertia, with the impact of load frequency response becoming more significant [30]. This means there is a growing need to accurately characterize and represent the frequency behavior of loads in modelling of this nature.

The various combinations of synchronous and emulated inertia modelled are illustrated in Figure 12. Combinations that meet the required frequency criteria are colored in green, while those that failed are colored in red. The trend line provides an indication of the relationship between synchronous and emulated inertia which complies with the acceptance criteria. This relationship is strongly dependent upon the manner in which the emulated inertial response has been modelled in these simulations. However, the slope of the line suggests that emulated inertia has the potential to "displace" the need for synchronous inertia, within certain parameters.

Figure 12 - Relationship between synchronous inertia and emulated inertia required to maintain frequency criteria [30]



In order to implement a solution involving FFR-type devices, the study recommended a TSO-led project to specify the necessary device characteristics, with further detailed analysis and/or demonstration testing [30]. They recommended that further analysis on alternative solutions to the RoCoF issue should only be performed if results from the primary RoCoF projects (to increase the RoCoF system limit from 0.5Hz/s to 1Hz/s) indicate that alternatives are required [30]. However, as outlined in Section 8.1, EirGrid/SONI are proceeding with the establishment of a suite of new frequency control ancillary services, including a "Fast Frequency Response" service with a response time of 2 seconds (sustained for 8 seconds). This will include a "Qualification Trial Process" to demonstrate the capabilities of emerging technologies to provide the specified services.

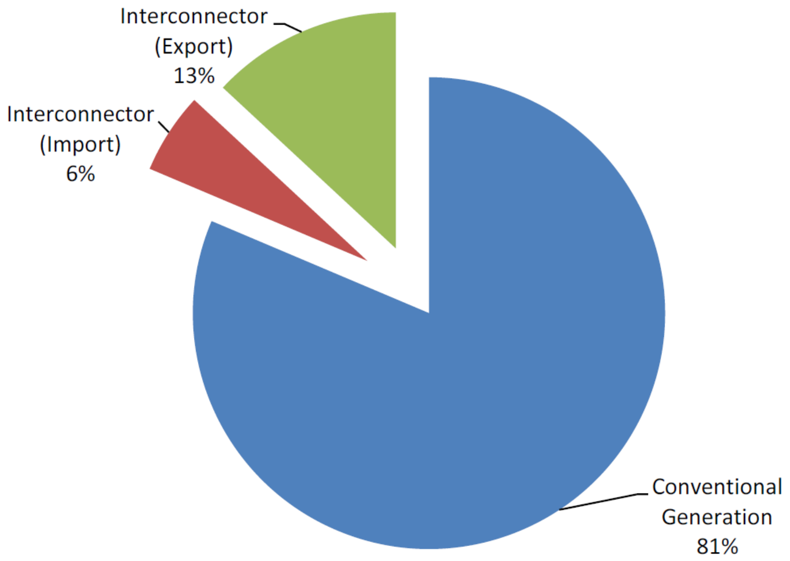
4.1.9 Special Protection Schemes

In situations where high RoCoF is related only to a specific event (such as the loss of an interconnector), this is often managed internationally via the implementation of a Special Protection Scheme (SPS), also sometimes termed a Remedial Action Scheme (RAS). These mechanisms directly detect the specific event of interest (such as the failure of the interconnector), and trigger the FFR immediately (without waiting for measurement of frequency or RoCoF). This could avoid many of the challenges related to detection and identification of high RoCoF events.

Mechanisms of this type have already been successfully implemented in Australia (to manage the loss of Basslink) and in other jurisdictions (such as the USA), and are appropriate where there is a single specific event to be managed.

However, SPS are of limited use in jurisdictions such as Ireland, where the largest contingency event of concern is often the loss of a generator (rather than the loss of the interconnector) [30]. This is illustrated in Figure 13, which shows the proportion of worst case contingency events of each type, calculated for every hour of the year in the study [30]. This illuminates the reason for EirGrid focusing on local frequency measurement, rather than direct event detection.

Figure 13 - Worst case contingency events in EirGrid modelling study [30]



4.2 National Grid (Great Britain)

National Grid established a Frequency Response Technical Sub Group in November 2010 to investigate issues such as the ability of wind turbines to contribute to system inertia. The group conducted modeling with DIgSILENT to investigate the system response to the largest loss (1,800MW) [19]. Although the modelling was specifically related to understanding the power system implications of an emulated inertial response from wind turbines, it is broadly relevant to FFR in a technology neutral sense, and therefore is discussed in this section of the report.

Their study found that the control strategy applied for FFR is of critical importance, to ensure that the right amount of active power is injected into the network, to balance the loss of generation. Too much active power could potentially result in over-frequency events [19].

Their analysis indicated that measuring RoCoF provided a good measure of the required level of active power injection. They modelled two controllers both using RoCoF functionality [19]:

1. A "one-shot" RoCoF controller, based on an initial injection and fixed decay based upon RoCoF, illustrated in Figure 14.
2. Based on a continuously acting RoCoF controller, which would operate throughout the entire disturbance, and in doing so regulating the active power injection to the network continuously (illustrated in Figure 15).

Figure 14 - Illustration of "one-shot" RoCoF control strategy [19]

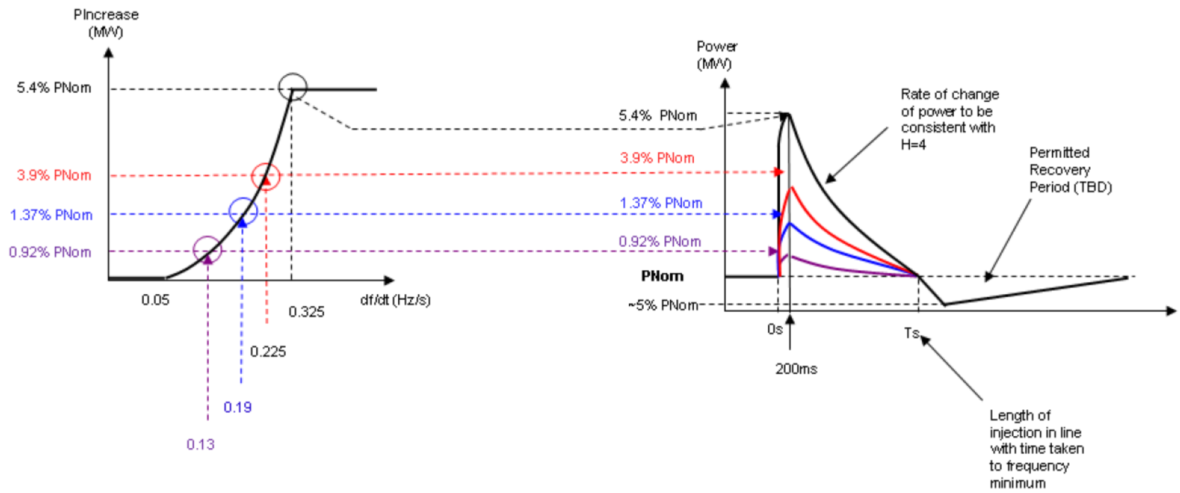
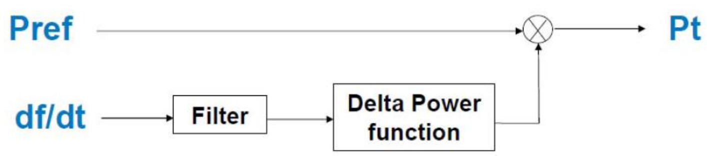


Figure 15 - Illustration of continuously controlled RoCoF controller [19]



Both controllers were found to be effective, and successfully maintain system frequency within limits. However, two critical issues were identified [19]:

- RoCoF controllers are noise amplifying and can, even with appropriate filtering, fail to operate in the appropriate manner, particularly where small time constants are involved. Furthermore, RoCoF measurements can be equally triggered by non-genuine generation losses, such as switching incidents. Appropriate filtering for these types of events is challenging on very short timeframes.
- The recovery period for wind turbines operating at just below rated wind speed can result in substantial reductions in their active power output (as much as 30%), resulting in a system frequency collapse some 10 to 15 seconds after the initial generation loss.

The first issue may necessitate the use of longer measurement windows. It also may be possible to use a frequency trigger, in addition to a RoCoF measurement.

On the recovery period, their analysis found that there was a serious risk of a significant volume of geographically dispersed wind generation operating at a similar wind speed just below rated speed, which could lead to active power reductions accumulating across the power system in response to a large frequency disturbance [19].

As a part of this project, the working group surveyed equipment manufacturers on wind farm capabilities [19]. Five wind manufacturers provided confidential feedback on emulated inertia and fast frequency response capabilities [19]. All of the replies from wind turbine manufacturers stated that fast frequency response (in 5 seconds) could be delivered by wind turbines, with the exception of one, who stated it was not possible to confirm at this time [19]. A number of replies highlighted that the delivery of frequency response by wind turbines was dependent upon the wind resource available [19]. No specific implementation costs were provided, but a number of the replies stated that development costs for them were likely to be associated with software and control systems, rather than in turbine hardware [19]. A number of replies also highlighted a desire to continue work on emulated inertia [19].

4.3 Systems with zero synchronous inertia

There is growing interest in the potential for operating large power systems with zero synchronous inertia. For example, the most recent IEEE Annual General Meeting of the Power & Energy Society (PES), held in July 2016 in Boston, included a panel session on "Challenges to Operate a Large Transmission Grid with Minimal or No Connected Synchronous Generators" [63]. This is one of the most significant power system conferences globally, indicating growing interest and activity in this field of research.

Presentations at this session highlighted that grids with no synchronous generation have been demonstrated at a small scale, in distribution systems of households, ships and within industry applications, and in off-shore DC connected windfarms [64]. However, they have never been demonstrated on a transmission scale [64].

They found that emulating the behavior of synchronous generation with emulated inertia from inverter-based devices is likely to be technically possible, but will require over-sized inverters, which is likely to be very costly [64].

Present-day inverters connected to the grid are "followers" – they measure the frequency (created by synchronous machines) and adapt their current injection to provide active/reactive power with the same frequency. In the absence of synchronous generators, some inverters would need to take on the role of being "grid forming", creating a voltage waveform on their own. Moreover, it would be necessary for all inverters to be synchronized at the same frequency, over the entire grid, regardless of grid topology, in a very distributed and robust way (avoiding the use of telecommunications), even during transient disturbances. Stable operation of a large transmission system without synchronous inertia should not depend upon the telecommunication system, which means it will be necessary to use something like the frequency to synchronize inverter operation [64].

State of the art technologies utilize a droop control response, to allow the inverter to mimic the operation of a synchronous machine [65]. This approach does have limitations, however; it assumes sinusoidal steady state conditions, and can have slow dynamics [65]. It is emphasized that power electronics can be fully controllable, but the appropriate control systems must be in place, and this is a field of research at present [64].

Open questions identified during this session included [64]:

- Determining the proportion of inverters that will need to operate as "grid formers", and to determine what happens when some grid forming inverters reach their maximum currents.
- How to control frequency, and consequently how to define and measure it during fast transients.
- How to draft requirements regarding these new constraints in grid codes.

This session highlights that the operation of large power systems with no synchronous inertia may be possible in future, but at present it is an area of active research [63].

Research of this nature will be progressing through the recently launched "MIGRATE" project (Massive InteGRATion of power Electronic devices), which aims to devise various approaches to solving key technical issues relating to grid stability, supply quality, and control and security of supply that arise owing to the challenge posed by the ever-increasing use of renewable energy feed-in sources [66]. One component of the work is to explore technology-based solutions to manage a transition towards an HVAC electric system where all generation and consumption is connected via 100% power electronics, based on innovative control algorithms together with new grid connection standards. The project will operate for four years, and is receiving 17 million euros from the EU [66].

4.3.1 National Grid (Great Britain)

As outlined in section 3.2, National Grid's modeling has indicated growing challenges around managing RoCoF. To address this anticipated challenge, National Grid established the "Enhanced Frequency Control Capability (EFCC)/SMART Frequency Control project" [67]. Running from January 2015 to March 2018, this project aims to:

- Demonstrate a new regional monitoring and control system for very fast response from multiple embedded providers, as well as faster initiated response from thermal power plants.
- Demonstrate the viability of obtaining rapid frequency response from solar PV, battery storage, and wind farms, and coordinate fast response from CCGT stations and demand side resources such as banks and water treatment plants.
- Develop technological solutions in combination with commercial frameworks,
- Ensure new generation technologies will be able to compete effectively with existing response providers in the balancing services market.

The flagship of the project is the establishment of an "Enhanced Frequency Response" (EFR) service, which requires an active power injection in 1 second (or less), sustained for 15 minutes. This is discussed further in section 8.3.

The project also includes a number of trials and demonstration projects. National Grid have been trialing various battery projects to provide fast frequency response, including different types of control strategies.

Specifically, National Grid is conducting trials of a "virtual inertia" product from a battery. This service simulates inertia by providing very fast active control (<20ms), and a very high short circuit power, with a sophisticated command and control scheme to mimic synchronous inertia [13]. In this way, it may eventually be possible to genuinely replace synchronous inertia with a battery response [13].

The trial will involve a Belectric high power (0.7-1.4MW, 948kWh) lead acid battery, optimized for frequency regulation (where the deliverable power depends upon the time and inverter configuration). The inverter and the control system will be optimised for fast response times [13]. Inverter based control schemes such as virtual inertia and frequency generation, will provide for a reaction time less than 20ms [13]. Control schemes invoking the operating system (frequency response, central command response) target a round trip time of under 100ms, applying stringent loop time control and a real time interface between the control system and inverter [13].

The project is anticipated to cost a total of £1,100k [13]. According to the project plan, the system will be installed and evaluated during the period October to December 2016, with frequency response trials taking place from January 2017 to September 2017 [13]. Knowledge dissemination activities are anticipated prior to the project close at the end of March 2018.

The results of these trials will be of great interest to AEMO, when they are published.

4.4 Conclusions

Terminology varies, but for this purposes of this report, a “Fast Frequency Response” (FFR) is defined as an active power injection, delivered within the first 1-2 seconds of a disturbance, to assist in arresting the frequency decline. In a low inertia (high RoCoF) power system, FFR is a potentially important service for mitigating high RoCoF, giving the governors of conventional generators (and other slower acting frequency control mechanisms) time to act to arrest, stabilize and restore system frequency.

Findings from this review on FFR are outlined below.

4.4.1 Insights for the NEM

4.4.1.1 Procurement mechanisms for synchronous inertia

International studies are clear that FFR is technologically and physically distinct from synchronous inertia. These should be considered as two different services, with different technical characteristics that interact differently with the power system.

At present, there are no examples of large power systems (hundreds of megawatts) operating with no synchronous generation. Modelling and analysis to date shows that FFR alone is not sufficient to maintain frequency, and is not a direct substitute for synchronous inertia. However, research in this field is active and growing, and may soon lead to sophisticated control systems that allow inverter-connected devices to set and maintain frequency, enabling genuine replacement of synchronous generation in large power systems. This would be a distinct service from FFR; it would continuously and actively set and maintain frequency (rather than being triggered by a RoCoF or frequency event), and therefore would not have the same challenges around measurement and identification of high RoCoF events as an FFR-type service.

This suggests that a procurement mechanism for synchronous inertia may be required in the NEM, to ensure that a minimum level of synchronous inertia is maintained for system security. This mechanism should ideally be designed such that it can transition over the longer term towards alternative inverter-connected solutions, as they are developed and demonstrated.

4.4.1.2 Fast Frequency Response service

International investigations have found that there are a range of technologies available to provide FFR-type services to assist in mitigating high RoCoF events, including batteries, flywheels, emulated/synthetic inertial responses from wind generation, and so on.

EirGrid/SONI's modelling suggests that an FFR-type service from inverter-connected devices could reduce the amount of synchronous inertia required to maintain system frequency. The precise relationship between the amounts required, however, will depend upon the specific characteristics of the FFR service. This suggests that exploring an FFR service in the NEM could be an important initiative to minimize the costs of mitigating high RoCoF. This would include quantifying the potential benefits of such a service in the NEM, and determining the parameters for its specification.

4.4.1.3 Managing stakeholder expectations

There is much excitement globally about the potential for emerging technologies to provide FFR-type services to mitigate high RoCoF. While these technologies show great promise in the long term, they are fledgling for this purpose at present, and there remain many challenges. In particular, analysis in Ireland and Great Britain has highlighted that robust and reliable measurement and identification of high RoCoF events poses a significant challenge, particularly over very short timeframes. Preliminary modeling suggests that the control mechanisms for the response of these devices is particularly important, and is at an early stage of development. International studies indicate that further research is required in this area before an FFR-type service could be implemented with confidence.

5 STORAGE TECHNOLOGIES FOR FREQUENCY CONTROL

This section explores the potential use of storage technologies for frequency control, including batteries, flywheels, and emerging hybrid technologies that may be well-suited to delivering a Fast Frequency Response service. The review explores practical demonstration of the technologies for frequency control, and other key findings from the analysis and research in this area internationally.

5.1 Hawaii

Hawaii includes six islands with significant electric utilities, and renewable penetration levels ranging from 83% (on Kauai) to 30% (on Lanai). There are no electrical interconnections between the islands.

Battery storage has been employed in Hawaii for various purposes, as listed in Table 15. Many of these battery storage systems are used for ramp rate control, or various frequency control aspects. This provides a practical demonstration that battery technology is capable of providing various frequency control services, particularly for managing ramp rate issues related to renewable generation in very small systems.

The 1MW battery system recently commissioned at Oahu may prove of interest to the NEM. This recently commissioned trial project is designed to provide fast frequency control (operating in less than one second), as well as general ramp rate control. It is employed at a distribution level (to assist with managing a feeder with high rooftop PV penetration). Their experiences over time with providing this service from a battery could provide valuable insights in commissioning a similar service in the NEM.

Table 15 - Hawaiian island renewable generation and storage

Island	Peak load (MW)	Renewable amount (MW)		Storage				
		PV	Wind	MW	MWh	Chemistry	Owner	Purpose
Oahu	1,100	356	99	1	0.250	Lithium titanate	Utility	Power smoothing (ramp-rate control) and frequency control operating in less than one second, on a feeder with high rooftop PV penetration. Trial project, went into operation at end July 2016.
				0.006	0.020	Lithium ion	Utility	Smooths loading and voltage at an electric vehicle charging station.
Maui	190	76	72	1.5	1	Advanced lead acid	Private	Ramp-rate control at a wind farm
				10	20	Advanced lead acid	Private	Part of a wind farm that was contractually required to provide very aggressive response to loss of load; allows conventional generator to operate at lower levels and wind to operate at higher levels.
				1	1	Lithium ion	Utility	Peak load shaving at a substation
				11	4.4	Lithium ion	Private	Ramp rate and voltage control at a wind farm (contractually required)
Hawaii	190	73	31	1	0.250	Lithium titanate	Utility	Ramp-rate control at a wind farm, and secondarily, to assist with island-wide frequency control (not fast).
				0.2	0.496	Lithium ion	Utility	-
Kauai	75	62	0	6	4	Lithium ion	Utility	Provides frequency control (not fast) and assists with island-wide ramp-rates
				13	52	Lithium ion	Utility	Dispatched via AGC by the system operator
				1.5	1	Advanced lead acid	Utility	Provides frequency control (not fast) and assists with island-wide ramp-rates
				3	2	Advanced lead acid	Utility	Provides frequency control (not fast) and assists with island-wide ramp-rates
Molokai	5.5	2	0	2	0.4	Lithium titanate	Utility	Intended to help with fast frequency smoothing and voltage control for island-wide rooftop PV. However, is not operating properly because of an inadequate inverter.
Lanai	5	1.5	0	1.1	0.5	Advanced lead acid	Private	Ramp rate control at a 1 MW PV plant.

5.2 PJM (USA)

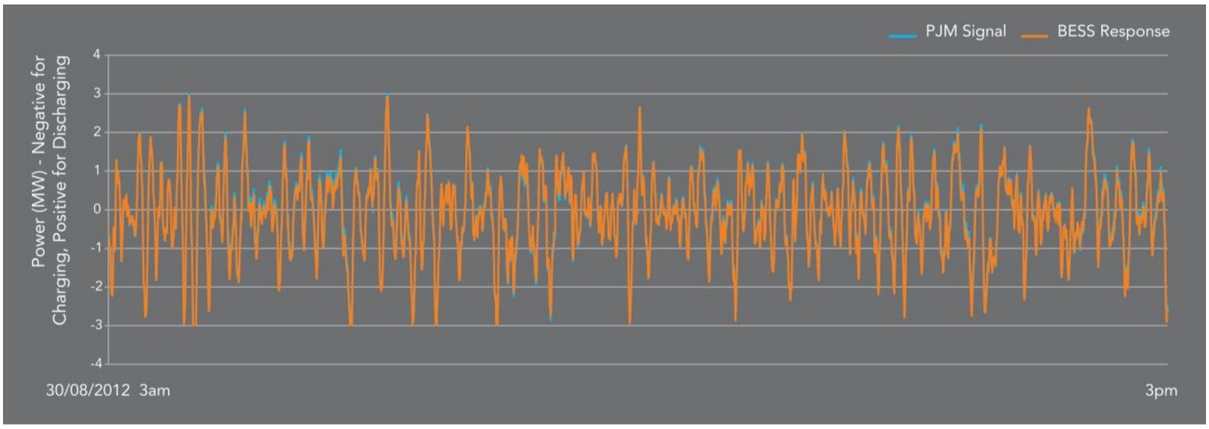
PJM is a part of the Eastern Interconnection in the USA, with a peak load of around 165GW [68]. As at April 2016, PJM has a total of 246 MW of battery storage projects installed [69], with a further 50MW of projects under construction, and a further ~700MW of projects under study [68]. Around 70% of storage projects deployed in PJM are based on lithium-ion batteries [70]. This world-leading capacity of storage technology has been established in response to the introduction of a new fast-response regulation market (discussed further below).

The bulk of these PJM installations have been deployed to provide grid frequency regulation services, with the lithium-ion systems having a discharge duration of 20-30 minutes [70].

5.2.1 Batteries for fast regulation

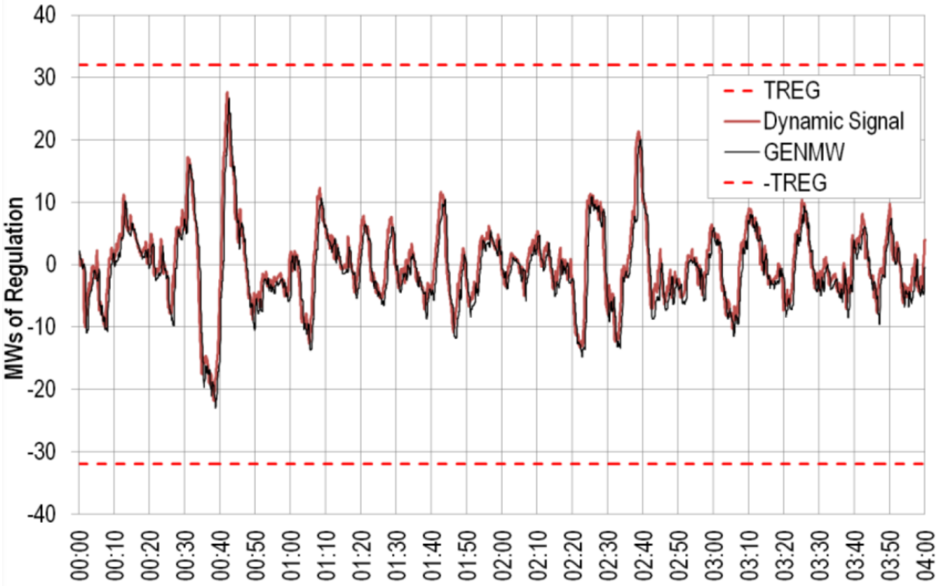
A one-megawatt array of lithium-ion batteries has provided regulation service in the PJM market for several years [69]. The battery facility, housed in a trailer on the PJM campus, was owned by AES Energy Storage. AES has now added a two-megawatt battery facility on the PJM campus. The total system provides 3MW of continuous frequency regulation services bidding into the open market on PJM, responding to PJM's fast response signal as illustrated in Figure 16 [71]. The system employs "UltraBattery" technology, which incorporates supercapacitors and Lead-Acid cell batteries to improve performance [72].

Figure 16 - PJM Regulation services signal and Battery Energy Storage System (BESS) response (30 Aug 2012) [71]



A much larger Lithium-ion battery facility (32 MW, 8 MWh) went into operation in 2011 in conjunction with a 98-MW wind farm at Laurel Mountain in West Virginia [69]. The battery facility provides a rapid regulation service in the PJM spot market [73]. The ability of this system to follow the PJM dynamic signal illustrated in Figure 17. It is reportedly capable of changing its output in less than one second [69].

Figure 17 - Response of the 32 MW battery at Laurel Mountain [74]

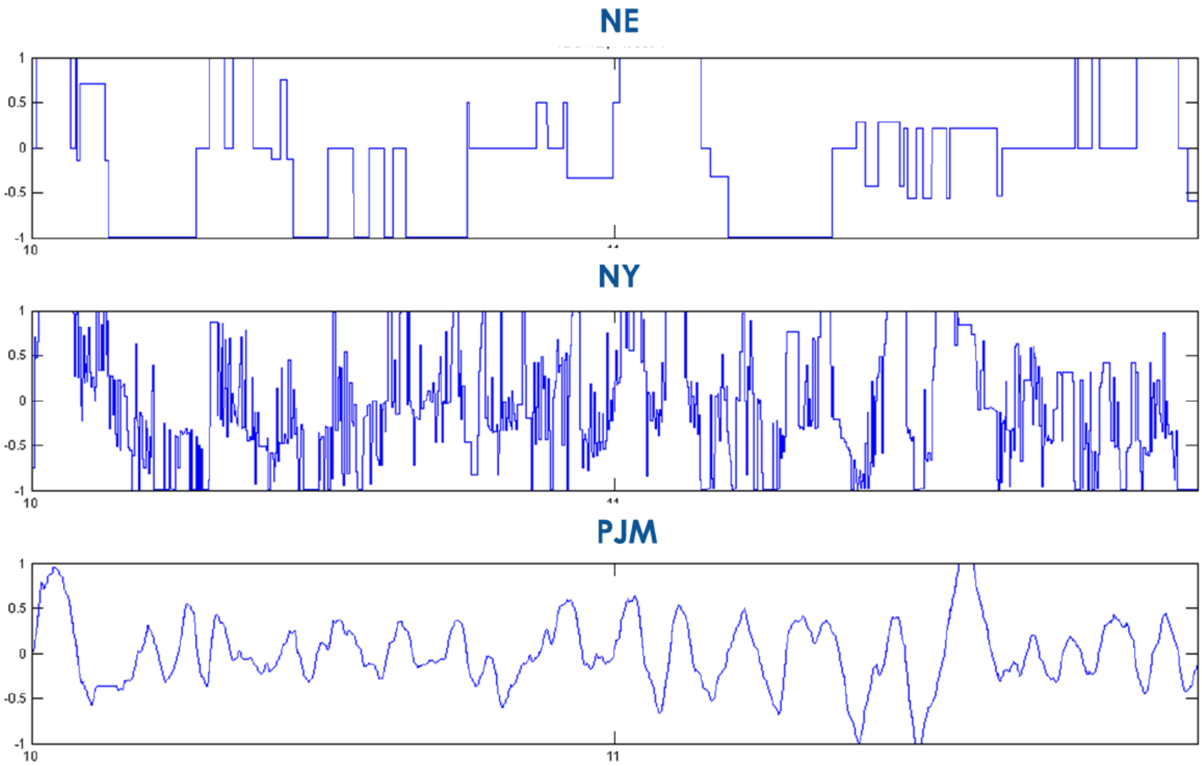


5.2.2 Flywheels for fast regulation

PJM also uses flywheel technology for regulation services. A 20-MW Beacon flywheel facility in PJM went into service in 2013 in Hazle Township, Pennsylvania [69, 73], with full commissioning in July 2014 [75]. The site incorporates 200 flywheels, each rated at 0.1 MW and 0.025 MWh, for a plant total of 20MW and 5 MWh [76]. The total project value was estimated at US$52,415,000 (in 2012) [76].

Figure 18 compares the use of this flywheel plant for regulation in the PJM market with two similar flywheel facilities (including a 20MW facility in Stephentown, NY, operating since 2011) [75]. Beacon Power note the substantial differences in how ISO's dispatch fast resources currently, indicating that markets are still developing in their utilization of these fast resources [75].

Figure 18 – Comparing the use of flywheel regulation in different ISOs (actual data from plant operations, normalized to ±1MW, showing a 2hr window) [75]



Similarly to this PJM facility, a Beacon Power flywheel system has been providing frequency regulation for the ISO New England grid since 2008 [69], and a 20-MW facility was completed in New York in 2011 [69].

5.2.3 Vehicle-to-grid demonstration

PJM is also exploring the use of vehicle-to-grid technology, with electric vehicles providing regulation services to PJM in a demonstration project with the University of Delaware and NRG Energy [69].

5.2.4 Why is there so much battery storage in PJM?

The Federal Energy Regulatory Commission (FERC) issued a ruling on 20 October 2011 (order number 755) [77], finding that the current compensation methods for regulation service in RTO and ISO markets "fail to acknowledge the inherently greater amount of frequency regulation service being provided by faster-ramping resources", and requiring RTOs and ISOs to:

> *"compensate frequency regulation resources based upon the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs, and a payment for performance that reflects the quantity of frequency regulation*

> *service provided by a resource when the resource is accurately following the dispatch signal."*

This was extended by FERC Order 784 on 18 July 2013, which required each public utility transmission provider to:

> *"take into account the speed and accuracy of regulation resources in its determination of reserve requirements for Regulation and Frequency Response service"*

PJM responded to these FERC Orders in 2012 by dividing their real-time market for regulation into two types of services: RegA (traditional, slower) or RegD (dynamic, faster) [78]. Modelling studies using KEMA's KERMIT tool found that the introduction of the fast regulation service improved the (already high) performance of PJM's regulation mechanism [79].

Regulation resources in PJM are paid for their performance (how quickly and how accurately they respond to PJM's signal). This performance-based approach rewards faster and more accurate resources with higher compensation [80]. In response, fast-ramping resources, in particular, have increased their share of the PJM market from 11% at the start of the performance-based regulation to 38% in October 2014 [81].

The new market design uses two separate payment types – one for capability (the cost of reserving megawatts) and one for performance (the cost of providing movements of output including mileage) [73]. The performance payment is multiplied by the additional amount of power that fast resources achieve compared to slower ones, resulting in a bonus mileage payment [73].

PJM's experiences demonstrate that battery storage systems and flywheels can be installed at significant scale, and used for rapid frequency control, although the application in PJM appears to be primarily rapid frequency regulation, rather than a contingency-type response (the main service of interest in the NEM for managing high RoCoF).

5.3 California (USA)

The California Public Utilities Commission (CPUC) has adopted a 1,325 MW procurement target for electricity storage by 2020, with target increasing every two years from 2016 to 2020 [70]. The targets are defined in three categories: transmission connected, distribution connected and behind the meter. The storage resources are procured biannually using a reverse auction mechanism (similar to the mechanism used in California for the procurement of renewable energy projects) [82].

The policy was implemented with three stated goals [83]:

1) *the optimization of the grid, including peak reduction, contribution to reliability needs, or deferment of transmission and distribution upgrade investments;*

2) *the integration of renewable energy; and,*

3) *the reduction of greenhouse gas emissions to 80 percent below 1990 levels by 2050, per California's goals.*

The focus of this initiative does not specifically mandate frequency control applications for the battery facilities installed, although it does define a range of possible "end uses" including the provision of ancillary services [84, 85].

This initiative suggests that there could be significant deployment of electricity storage projects in California in the coming years, but in the absence of more directed use for rapid frequency control services it may be of little relevance in demonstrating the types of technologies of interest to AEMO.

5.4 National Grid (Great Britain)

National Grid conducted analysis of existing battery storage sites, for suitability for fast frequency response trials [13]. Their findings included:

- Flow type batteries were not suitable because they cannot provide sufficiently fast <0.5s response times. Due to the time taken for electrolytes to mix that is inherent with this technology to produce a change in power output, fast response times cannot be achieved. Additionally, the power to capacity ratio of these batteries is not favorable for short-term, high-power applications (such as Fast Frequency Response).
- Even for other types of existing batteries considered more suitable for fast frequency response, the anticipated response time is around 0.5 -1 second. Although faster response times are possible for new installations, these existing battery installations were not originally optimized with this in mind.
- It is preferable for the battery to have a high power output (relative to installed capacity), to maximize the potential contribution for mitigating RoCoF. Many

existing battery facilities have not been originally optimized with this in mind, and therefore have limited suitability for fast frequency response.

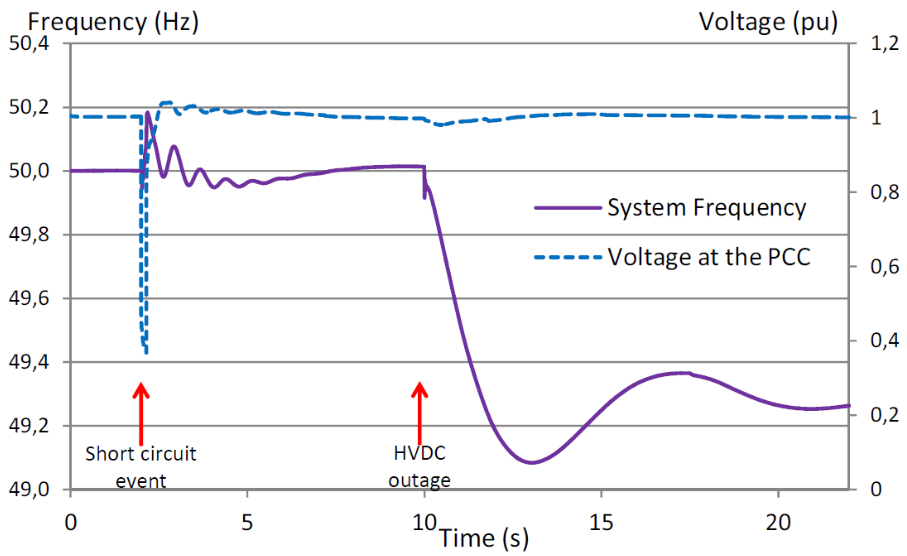
These insights illustrate that although battery systems can deliver a very rapid frequency response, they must be designed to do so. If it is required, this capability must be specified during the project design phase.

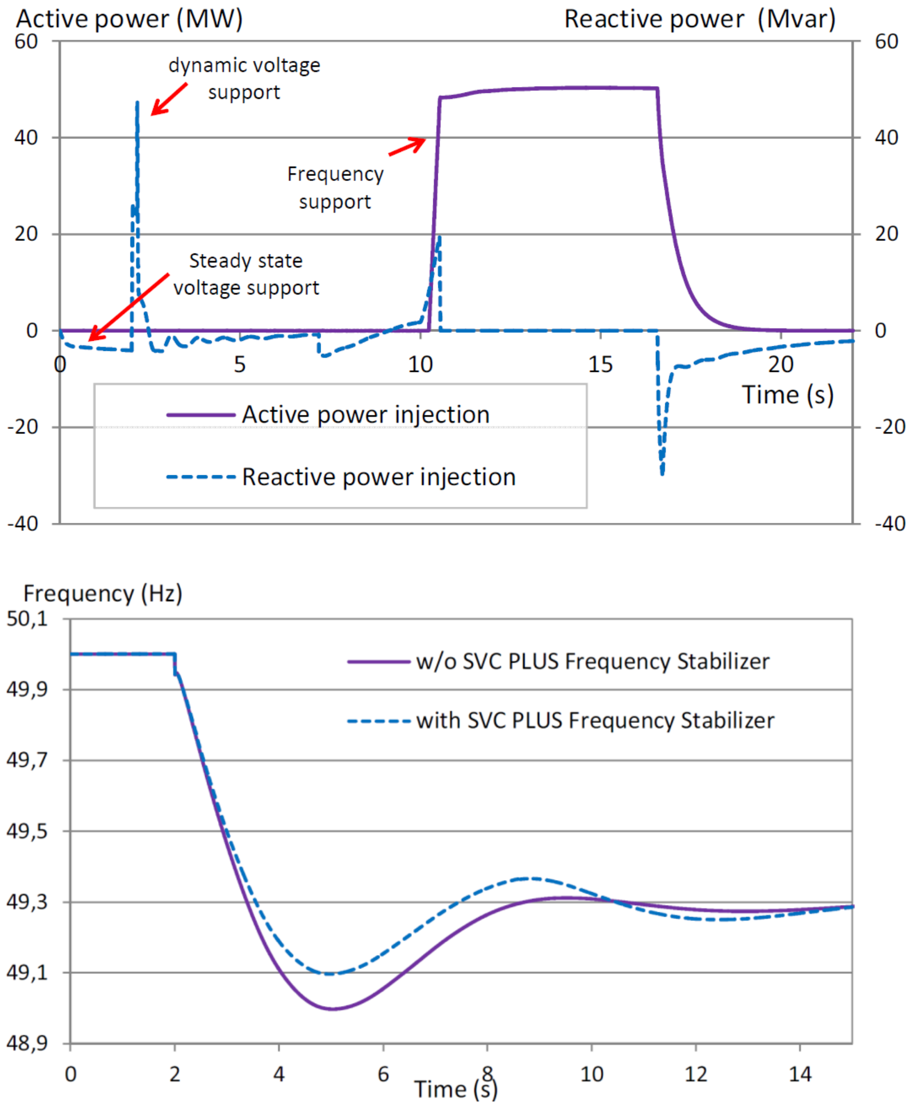
5.5 Emerging technologies

Manufacturers have recognized the emerging opportunity for technologies to manage high RoCoF, and are in the process of developing new products to meet this need. For example, Siemens is now developing a product they term "SVC PLUS FS" (SVC plus frequency stabilizer), which acts as a multilevel STATCOM with power intensive supercapacitors to provide "artificial inertia" for both frequency and voltage grid support [12]. This device is anticipated to be available as a commercial product in the first half of 2017.

Simulation results illustrating the behavior of this device in the Irish power system are presented below. The modelling shows a short circuit event at t=2s for 150ms duration, and the outage of the HVDC connection with Great Britain at t=10s [12]. The system frequency and voltage at the point of connection are shown, as well as the active and reactive power from the device. The active power response is very rapid. The operation of the device improves the frequency nadir by ~0.1Hz, avoiding load shedding in this particular example [12].

Table 16 - Simulation of STATCOM with storage for frequency and voltage grid support [12]





The vendors claim that this device (SVC PLUS FS) can deliver the same fast frequency response capability as a battery, but at a lower cost (they suggest that an equivalent battery would be 3-5 times more expensive) [45].

As RoCoF issues become an issue in a larger number of jurisdictions, it is reasonable to expect that manufacturers will develop more sophisticated devices for managing these challenges. The technology is fledgling at present, but evolving rapidly. This suggests that AEMO should apply a cautious approach to the specification of any new ancillary services, ensuring that the specification is as technology-neutral as possible, allowing flexibility for the development of sophisticated new technologies to meet the identified need.

5.6 Conclusions

Batteries have been deployed at significant scale in various other markets, including various applications in frequency control. For example, in PJM, batteries and flywheels are now the dominant technology entering the market to provide dynamic (fast) regulation , with almost 250 MW installed (mostly lithium-ion batteries). Hawaii also has a range of battery projects in operation, assisting with ramp rate control at wind and solar generators. Korea Electric Power Corporation, the national utility of South Korea, is currently deploying the largest utility-based, battery energy storage system in the world. The system, when fully deployed in 2017, will total 500 MW.

However, this review did not encounter *any* examples of storage technologies being currently used in practice in other systems to provide an FFR-type service (defined as an active power response in 1-2 seconds or less, following a contingency event, to assist in managing high RoCoF). This is relatively unchartered territory.

Further findings from this review on FFR are outlined below.

5.6.1 Insights for the NEM

5.6.1.1 Technology neutral approach

Inverter-connected technology for managing high RoCoF is in a fledgling state at present, but is evolving rapidly. For example, Siemens is developing a product that acts as a STATCOM with power intensive supercapacitors to provide “artificial inertia” for frequency and voltage grid support [12]. Other manufacturers are likely to be exploring a range of other potential options. Such technologies show potential to be highly responsive and cost effective. This suggests that the specification of any new service (such as an FFR-type service) should be as technology-neutral as possible, focusing on power system needs rather than technology capabilities, and allowing flexibility for developing sophisticated new technologies.

5.6.1.2 Encouraging fast response characteristics

Storage technologies are capable of very fast response times, but this capability must be designed into the system when it is initially developed. Standard battery projects (designed for other purposes) may not be capable of delivery an FFR-type service, unless this is specifically included in the specifications of the project. For example, National Grid’s review of existing battery installations found that very few would be capable of delivering fast frequency services without costly retrofitting [13].

It appears likely that FFR capability will be desirable in future, so battery projects now under development should be designed with this in mind. AEMO could consider engaging with organizations that promote and support such projects (such as project developers and the Australian Renewable Energy Agency) to encourage the inclusion of rapid frequency response capabilities.

6 DEMAND RESPONSE FOR FAST FREQUENCY CONTROL

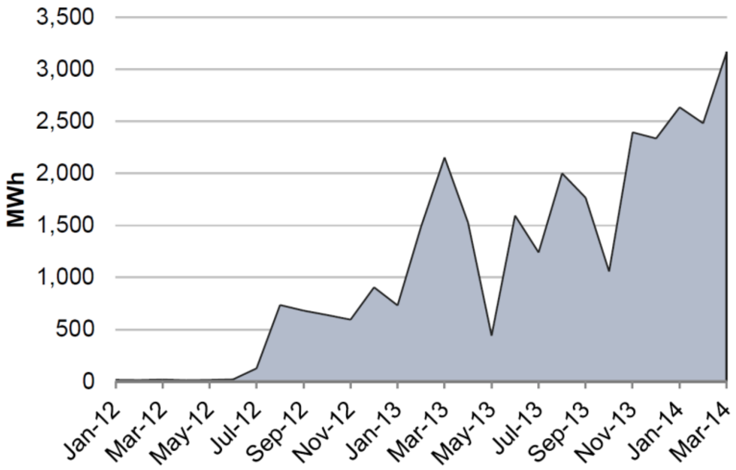
This section explores international examples of the use of demand response for fast frequency control, including regulation and contingency services.

6.1 PJM

Demand response resources were approved to provide frequency regulation services in PJM in 2008, but did not actually clear PJM's market until 2011 because the market rules, including a 1 MW minimum offer requirement, made participation impractical [86]. The minimum size restriction acted as a barrier to entry for new demand response aggregators, particularly aggregators of small residential loads [86].

Following a rule change in November 2011 that removed several barriers, demand response participation in the PJM regulation market skyrocketed [86]. Figure 19 shows the monthly megawatt-hours of regulation provided by demand response in PJM since January 2012.

Figure 19 - Monthly regulation services provided by Demand Response in PJM [86]



For example, a company active in the PJM territory, known as VCharge, aggregates thermal storage heaters to provide low-cost heating and regulation services to PJM. VCharge's fleet of heaters is able to respond to area control error signals in 2 seconds [86].

Importantly, VCharge and other third-party demand response providers are able to participate in PJM's market due to market rules that accommodate a wide variety of resources. Firstly, PJM allows for aggregated loads to supply ancillary services [86]. Further, the VCharge program, and other demand response resources similar to it, were able to participate in the balancing reserve service after PJM lowered the minimum size requirement for resources from 1 MW to 0.1 MW [86]. This suggests that the minimum size requirements for demand aggregators to provide frequency control services should ideally be no larger than 100 kW [86].

6.2 New Zealand

In New Zealand, the system operator procures two types of Fast Instantaneous Reserves (FIR) [47]:

1. From generators providing partly loaded spinning reserve and tail water depressed reserve, FIR is the additional capacity (in MW) provided within 6 seconds after a contingency event, sustained for a period of at least 60 seconds.
2. From interruptible loads, FIR is the drop in load (in MW) that occurs within 1 second of the grid system frequency falling to or below 49.2Hz, sustained for a period of at least 60 seconds.

The 1 second interruptible load service provides a practical demonstration at scale of the capability of load response to rapidly arrest a frequency decline, operating in less than one second.

6.3 Conclusions

Demand response has been demonstrated internationally to have the potential to provide various kinds of rapid frequency control. For example, demand response provides regulation services in PJM, and New Zealand has a 1 second contingency service specifically provided by demand response. Demand response could provide an important and cost effective source of FFR-type services in the NEM, if the service is specified appropriately and barriers are removed.

6.3.1 Insights for the NEM

6.3.1.1 Minimum size for demand-side aggregators

A 1 MW minimum size for demand aggregation was a significant barrier to demand-side participation in frequency control markets in PJM. Reducing this minimum size to 0.1 MW appeared to eliminate this barrier, and demand-side providers are now active in PJM's frequency control markets.

The NEM also has a 1 MW minimum size requirement for registration to provide frequency control services. Based upon PJM's experience, this may be a barrier to demand-side participation, and may warrant further investigation around the costs and benefits of alleviating this issue.

7 EMULATED INERTIA FROM WIND TURBINES

This section explores international experiences with emulated inertia (also termed synthetic inertia) from wind turbines. Practical experiences and key lessons from Hydro-Québec are explored, as well as the specification of inertial emulation requirements in several other jurisdictions.

7.1 Technical nature of the emulated inertial response

7.1.1 Differences between emulated and synchronous inertia

To provide an emulated inertial response, the wind turbine inertial control utilizes the kinetic energy stored in the rotor to provide an increase in active power. This does not adversely impact annual energy production (it is not necessary to continuously spill energy in order to provide this service) [87].

As discussed below, Hydro-Québec requested that the emulated inertial response have a similar functional response to that of a synchronous machine [87]. However, there are some important differences between a synchronous inertial response, and an emulated inertial response from a wind turbine.

Firstly, the emulated inertial response is implemented with a dead band, which suppresses the response of the controller until the control error exceeds a threshold. Thus, the controller only responds to large events. The continuous small perturbations in frequency that characterize normal grid operation are not passed through to the controller [87].

Secondly, the control is asymmetric; it only responds to low frequencies. High frequency controls are handled separately, by a different controller that can, if necessary, provide a sustained response [87].

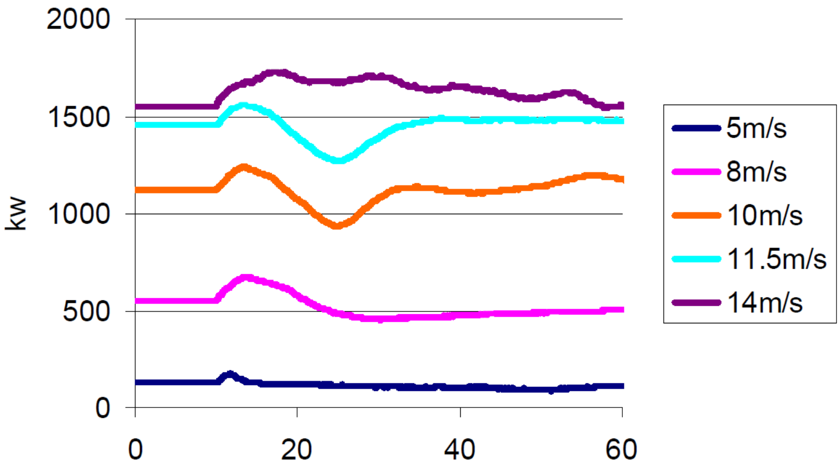
Thirdly, the speed of the response is a function of the control parameters (not an inherent physical characteristic of the device). This means that the characteristics of the emulated inertial response can be fine-tuned (and turned off, if necessary), which provides an additional tool to manage system stability [87]. Many manufacturers have designed the response of their present products around the Hydro-Québec requirements and system, including providing good coordination with the inertial response of other generation in that system, and with the governor response of their conventional generation [87].

7.1.2 The Recovery Period

The wind turbine inertial response is essentially energy neutral. Below rated wind, stored kinetic energy from the turbine-generator rotors is temporarily donated to the grid, but is recovered later [87]. At higher wind speeds, it is possible to increase the captured wind power, using pitch control, to temporarily exceed the steady-state rating of the turbine. Under these conditions, the decline in rotor speed is less and the energy recovery is minimal [87].

Field test results of the inertial control on a GE wind turbine for various wind speeds on a single wind turbine are shown in Figure 20 [87]. The field data was generated by repeated application of a frequency test signal to the control. The results, at various wind speeds, were then averaged and plotted [87]. Below rated wind speed (<14m/s) the results demonstrate the inertial response and recovery. Above rated wind speed the inertial response is sustained by extracting additional power from the available wind (i.e. short-term overload of the wind turbine) [87].

Figure 20 - Field demonstration of a GE wind turbine emulated inertia response [87]



The inertial control increases the power output of the wind turbine in the range of 5% to 10% of the rated turbine power [87], for a duration on the order of several seconds.

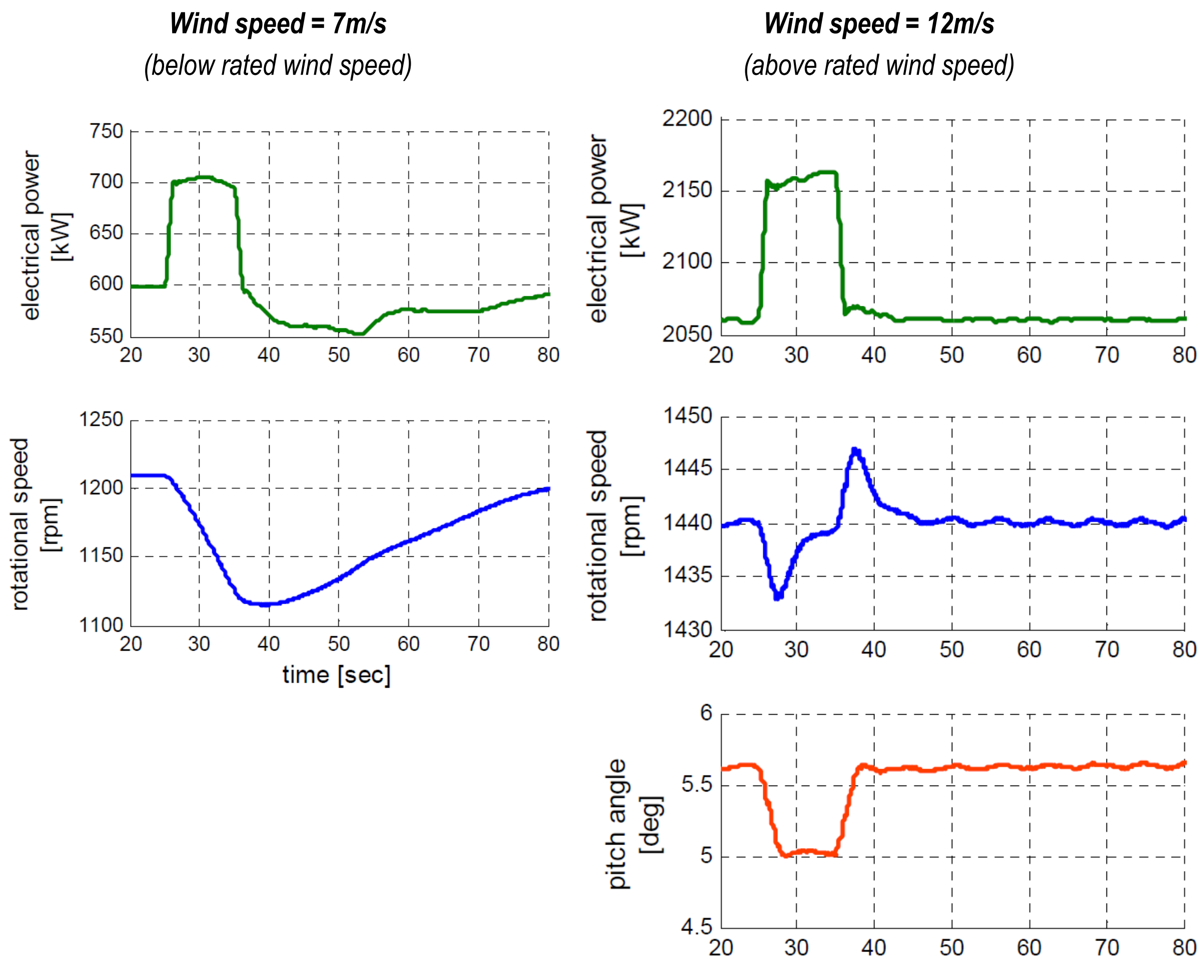
For comparison, Figure 21 illustrates the emulated inertial response of a REPower MM92 wind turbine [88]. At approximately 25 seconds the wind turbine is requested to contribute an additional 100kW of active power (~16% of the actual active power, or ~5% of nominal active power) for approximately ten seconds.

Consider first the left figures, which illustrate the turbine response when operating at a wind speed of 7m/s. The upper figure (in green) shows the emulated inertial active power response. The lower figure (in blue) shows the rotational speed of the wind turbine, which decelerates as the energy from the emulated inertial "boost" is taken from the rotational energy. This "breaking" process continues until the boost stops. At this point, the wind turbine has reached the minimum rotational speed that can be tolerated (~100rpm less compared to the pre-event speed) [88].

Following the "boost" period, the wind speed has to accelerate the wind turbine again in order to bring the turbine back to the optimum operational level (the "recovery" period). In this particular example, it takes approximately 45 seconds for the wind turbine to return to the pre-event rotational speed and active power output; in general, this duration will depend upon the moment of inertia of the turbine, the operational level, and the height and length of the boost period (as well as further adapted control during recovery, depending upon the power system operator's preferences) [88].

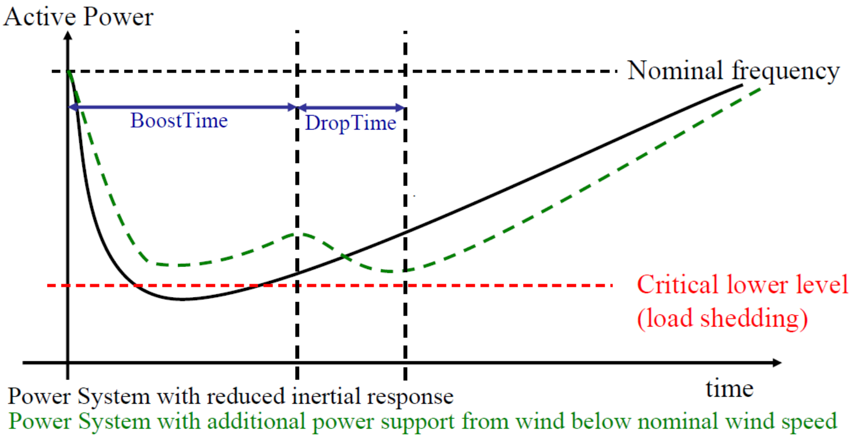
Consider now the right figures, which illustrate the emulated inertial response of the turbine for a wind speed of 12m/s (above rated wind speed). In this example, the turbine can use pitch control in order to maintain constant rotational speed and constant (maximum) active power output [88]. In this case, there is no recovery period, and the rotational speed deviation from the pre-event speed is negligible. The bottom figure illustrates that the active power is taken from a reduction of the pitch angle, rather than from the energy stored in the spinning mass of the turbine blades. It should be noted that this capability requires a dynamical overload capability [88].

Figure 21 - Inertial response of a MM92 REPower 2MW wind turbine (simulated) [88]



The energy deficit during the recovery period, and the influence of wind speed on the emulated inertial response create complications at a power system level, when attempting to anticipate the total system response to a contingency event. Figure 22 illustrates a schematic of the potential power system response, showing how the initial active power response from wind turbines could avoid arrest the initial frequency decline and avoid load shedding, but still accommodate the active power deficit during the recovery period [88].

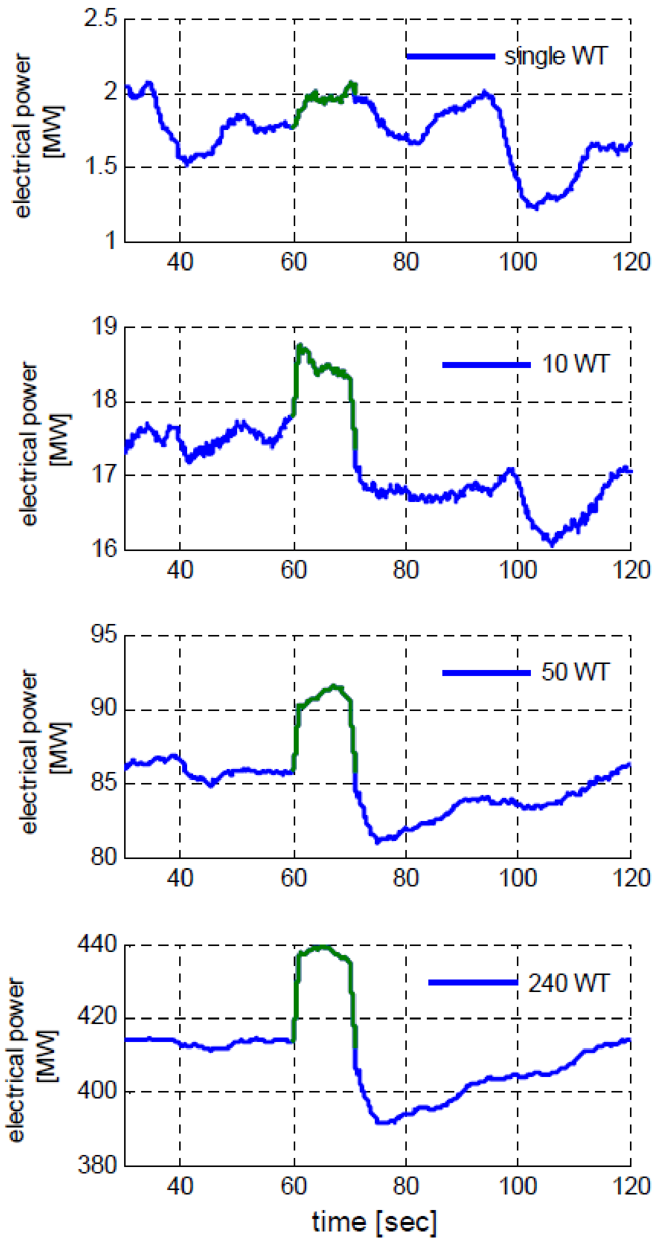
Figure 22 - Schematic frequency response characteristic of a transmission system with additional active power contribution from wind turbines [88]



7.1.3 Turbulence

Turbulence (variability in the wind speed) can create some complications during the testing of individual turbines, because the emulated inertial response can be difficult to distinguish from normal fluctuations in power due to wind speed changes. However, the response is more clear when aggregated at a wind farm level, as illustrated in Figure 23. In this example, the emulated inertia boost is activated at 60 seconds, and sustained for 10 seconds.

Figure 23 – Simulated emulated inertial response from a single MM92 turbine, 10 wind turbines, 50 wind turbines and 250 wind turbines (mean wind speed 10m/s, 10% turbulence intensity) [88]



7.2 Hydro Québec (Canada)

Hydro-Québec TransÉnergie manages the generation, transmission and distribution of electricity in Quebec, Canada. This system is interconnected to the Eastern Interconnection with a 4 GW HVDC link.

In 2005, Hydro-Québec had 1,500 MW of planned wind generation, and was preparing for an additional new 2,000 MW wind generation call for tenders [89]. The resulting 3,500MW of wind generation anticipated by 2015 would represent a penetration of around 10% of peak load, and close to 25% at light load [16]. An analysis performed to quantify the impact of this addition of wind generation identified a need for "inertial response" from wind turbines [89], as discussed further below.

In 2006, Hydro-Québec introduced the requirement for an emulated inertial response from new wind farms connecting to their system [89, 16]. In 2010, they were the first transmission owner to integrate wind plants equipped with this capability into their network [87]. Studies of system integration are ongoing [90].

For some years, Hydro-Québec was the only grid operator in North America to require wind generators to provide a frequency response of this type [91].

7.2.1 Specification of the emulated inertia requirements in Hydro Québec

Hydro-Québec specifies the emulated inertia requirements for wind generation in their grid code as follows [92]:

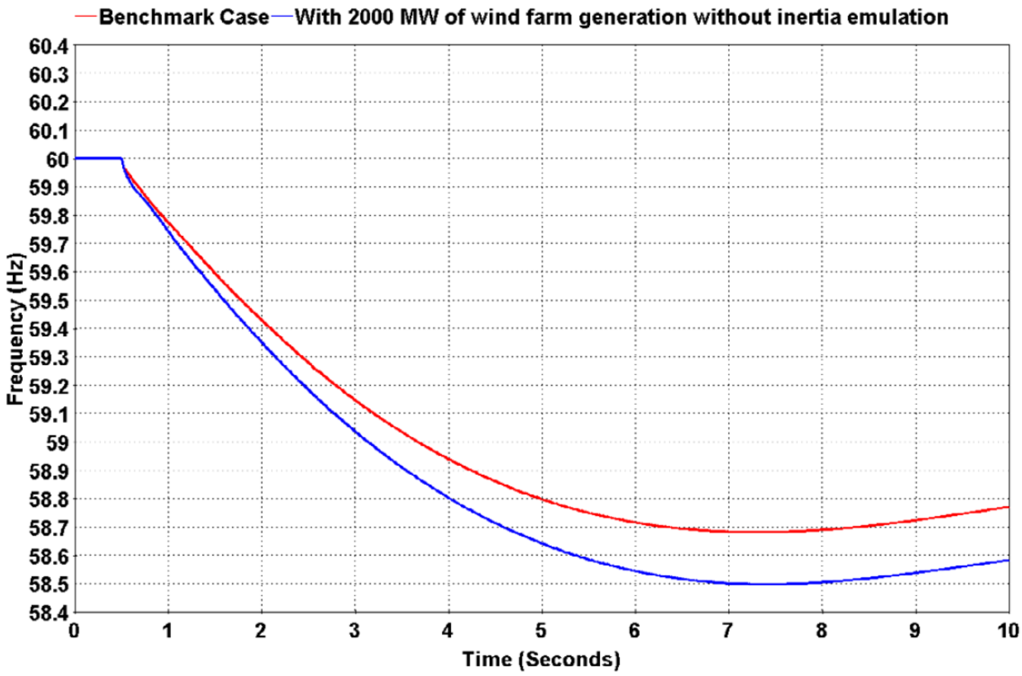
> *"Wind power plants with a rated output greater than 10MW must be equipped with a frequency control system. The system must be continuously in service, but only act during major frequency deviations. It will not be used for steady-state frequency control.*
>
> *The purpose of the system is to enable wind power plants to help restore system frequency and thus maintain the present level of transmission system performance during major disturbances.*
>
> *To achieve this, the system must reduce large, short-duration frequency deviations at least as much as does the inertial response of a conventional synchronous generator whose inertia (H) equals 3.5s. This target performance is met, for instance, when the system varies the real power dynamically and rapidly by at least 5% for about 10s when a large, short-duration frequency deviation occurs on the power system."*

In 2008, Hydro-Québec also published a general validation test program for wind turbines connecting to its system, which includes specific testing modules for the inertial response [93].

7.2.2 Studies that lead to the emulated inertial requirement

Hydro Québec's simulations indicated that if 2000 MW of hydro generation was replaced by wind turbine generators without inertial response, the frequency nadir will deteriorate by about 0.2 Hz within the first 10 seconds [94], as illustrated in Figure 24. Load shedding occurs in Hydro-Québec at 58.5Hz, indicating that the blue curve excursion is low enough to trigger load shedding [89]. The contingency simulated is the loss of ~1450 MW of hydro generation [16]. Very few other details are publicly provided on this modelling [89]. Since this modeling indicated that anticipated growth in wind generation could lead to load shedding, Hydro Québec introduced a requirement for wind power plants to provide an "inertial response" to the network [89].

Figure 24 - Impact of the addition of 2000MW of wind generation without inertia emulation [89]



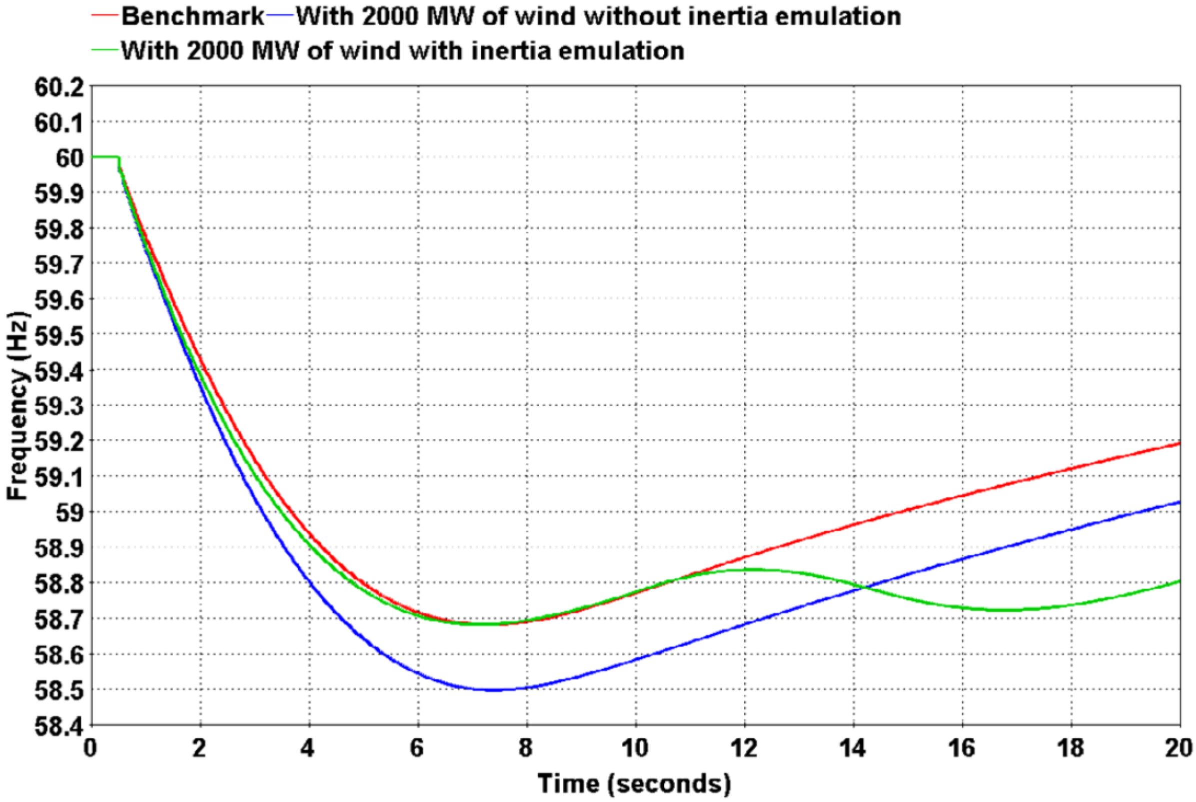
Hydro Québec ran some simulations to understand what parameters the wind plant should target in order to facilitate a similar frequency response to a system with all synchronous generators [89]. This analysis was intended as a guideline for manufacturers, with the final design remaining to be validated by additional studies and field tests. The study assumed two different types of control: a step function, where the response would come immediately, and a proportional function where the response would be provided more slowly. The results are shown in the table below, and were used by manufacturers as an indication of Hydro Québec's preferred performance characteristics [16].

Table 17 - Hydro-Québec parameters for wind power plants >10MW providing an emulated inertial response [95]

Parameters	Parameter Description	Proportional Function	Step Function
Deadband	The frequency deviation at which the emulated inertia response will activate.	0.3 Hz	0.5 Hz
Active power contribution	The minimum amount of energy above the current power output the plant must produce.	6%	6%
Duration of the active power contribution	The minimum time at which the plant must sustain its active power contribution before going into recovery phase.	10 seconds	10 seconds
Activation time	The maximum time after the event occurs before the response is given.	1 second	1 second
Transition time	The minimum time at which the active power contribution goes into a recovery phase in order to recover the energy and bring turbine speed back to its initial speed.	3.5 seconds	3.5 seconds
Maximum generation reduction during recovery phase	The maximum amount of power reduction when the plant goes into recovery phase.	20%	20%

Figure 25 illustrates the power system performance modelled with the recommended parameters for a proportional inertia emulation scheme, as listed in Table 17. Note that the Hydro-Québec needs are currently focused on limiting the frequency nadir, and not on limiting RoCoF (which is of key interest in the NEM) [16]. The introduction of the emulated inertia response was modelled to be sufficient to avoid load shedding at 58.5Hz.

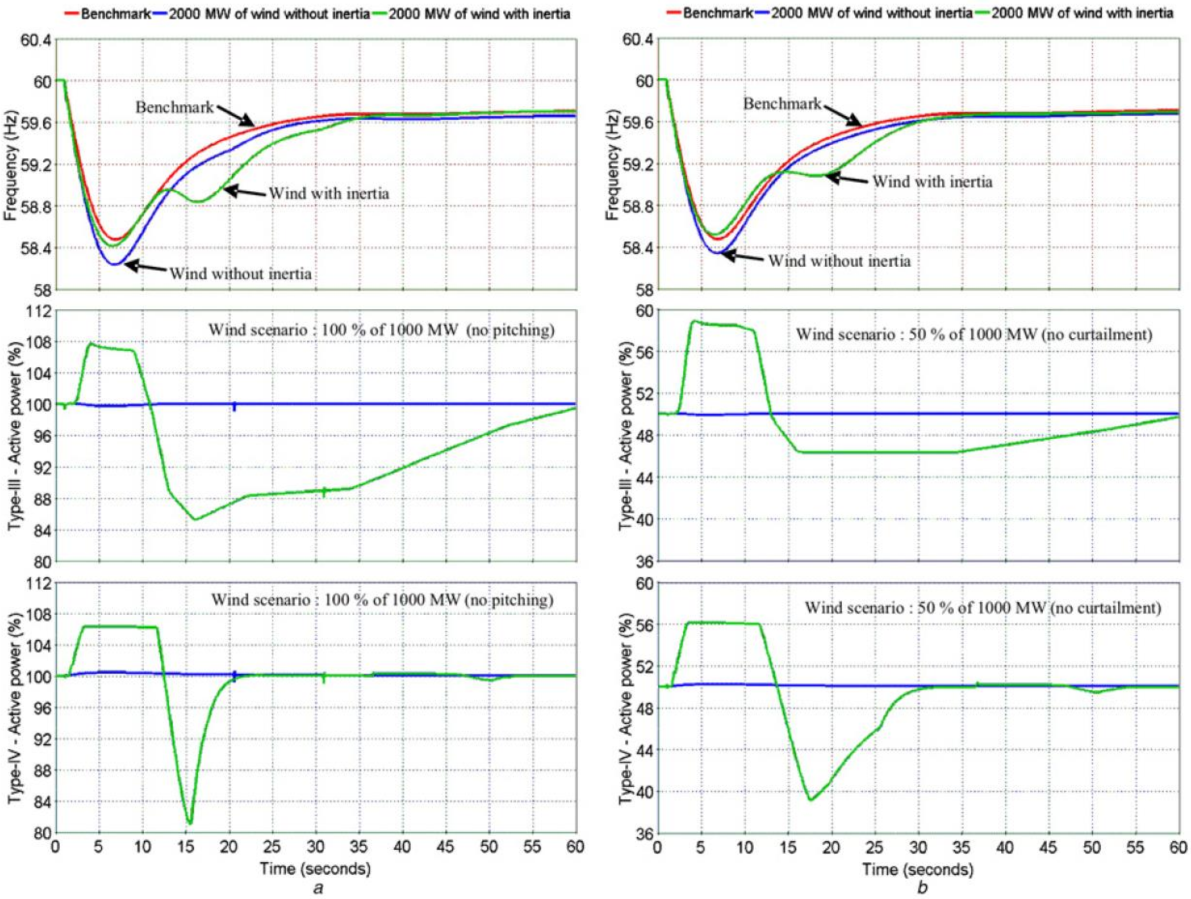
Figure 25 - Impact of inertia emulation on system frequency for a 2,000MW wind farm generation addition [89]



7.2.3 Simulations using manufacturers models of wind emulated inertia

More recently, Hydro-Québec has "updated" these simulations (illustrated in Figure 25) with the models provided by manufacturers. Key results are shown in Figure 26, for the identical scenario, but applying the manufacturer's models (at different levels of wind operation). The middle panels show the model response for a Type III turbine, and the lower panels show the response for a Type IV turbine model. The two models investigated show a different response, but both were found to satisfy the needs expressed by Hydro-Québec [16].

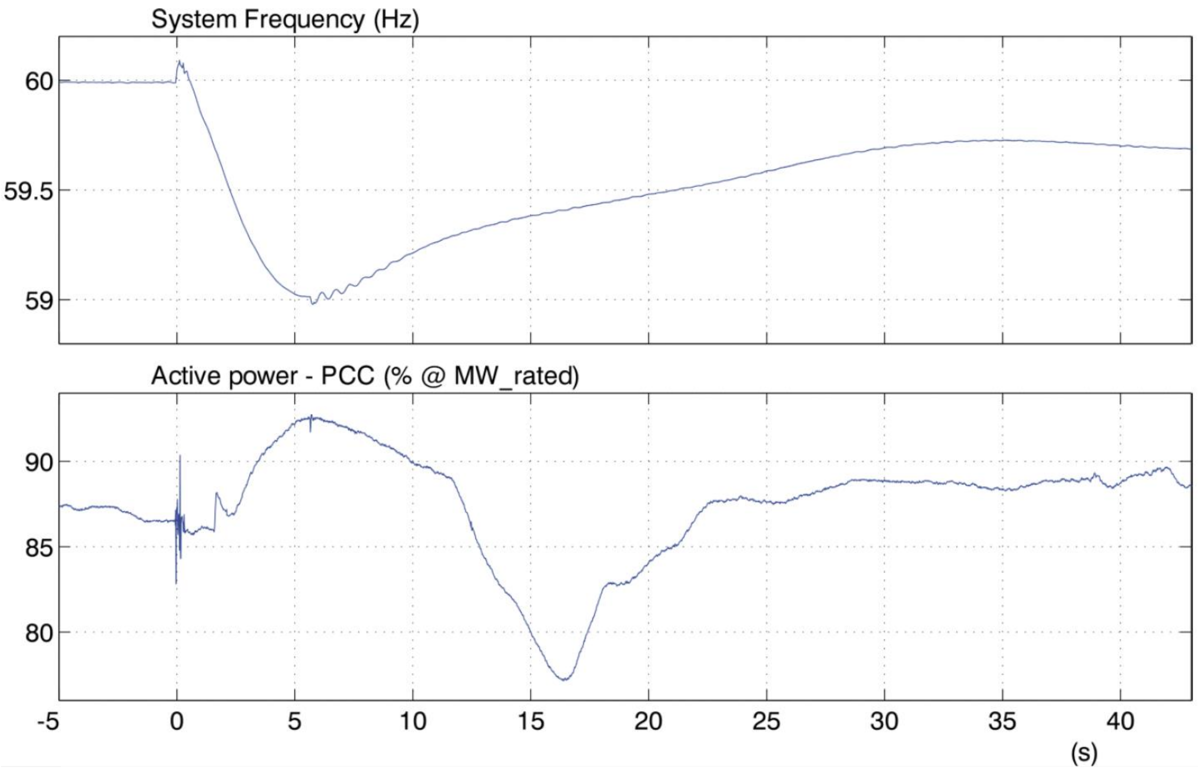
Figure 26 - Update of Hydro-Québec modelling using models from manufacturers. a) Wind operating at 100%, b) Wind operating at 50% [16]



7.2.4 Power system experiences with emulated inertia

Figure 27 provides an example of the measured emulated inertial response of a wind power plant in Hydro-Québec, in response to an actual system frequency event. The emulated inertial response is ~5% of the nominal capacity of the wind farm, over a period of ~3-4 seconds. The recovery period is evident, since the wind plant was operating just below rated wind speed during this event [90, 3].

Figure 27 - Emulated inertia response from a wind power plant - Example of a recorded event in Hydro-Quebec (PCC: Point of Common Coupling, connection point to the grid) [90, 3]



Hydro-Québec have very recently (2016) published some more detailed analysis on practical power system experiences with the emulated inertial response from wind generation [16]. Figure 28 shows two examples of the measured behavior of Type IV wind turbines during two different under frequency events initiated by a loss of generation. Figure 29 shows the equivalent for Type III wind turbines.

Figure 28 a) on the left illustrates results for a wind farm consisting of Enercon E70 2.3MW turbines, with typical settings that are equivalent to the "proportional function" defined by Hydro-Québec (Table 17). The top panel illustrates the system frequency during the event. The contingency event occurred at t=0, and the system frequency nadir reached 58.8Hz, which was sufficient to trigger the emulated inertial response from the wind turbines.

The second panel shows the active power response measured at an individual wind turbine generator (WTG) in red, and the Wind Power Plant (WPP) in blue. At the time of the event, the individual turbine was operating at 74% of rated power, while the whole farm was operating at 50% of rated power. When the event occurred, the wind turbine increased active power by 10% of nominal rated power, while the whole farm increased active power by 7%. Note that these wind turbines were designed to increase their power by at least 6%

of their nominal power, as indicated in Table 17, and the observed response was above this amount.

The emulated inertial response lasts for a duration of ten seconds, followed by a five second "fall time", entering the recovery period. The wind turbine active power reduces by 54% during this period; this very significant reduction is exacerbated by a reduction in wind speed from 13 to 10.5m/s. This is smoothed across the whole wind farm, however, with a relatively smaller reduction in power of 25.4%. The recovery period lasted for a duration of ~14 seconds.

Figure 28 b) on the right illustrates results for an Enercon E82 2.3MW turbine, with alternative settings similar to the step function (Table 17). In this case, the wind farm is operating at 25% of rated power immediately prior to the event. When the event occurs, the farm increases active power by ~6%, for a duration of ~10 seconds, as designed. The active power reduction in the recovery phase is less severe in this case, falling only 9%, for a slightly longer duration of ~20 seconds. The wind speed fluctuation in this example was less, which contributed to the less severe recovery period behavior. These wind turbines also have longer blades than the previous example, which leads to a higher inertia constant.

Figure 28 – Type IV wind turbines - Measured emulated inertia response in Hydro-Québec (two different events) [16]

a)	b)
Wind Power Plant (WPP) consisting of **Enercon E70 2.3 MW type IV** Wind Turbine Generators (WTG), with typical settings equivalent to the "proportional function" defined by Hydro-Québec (Table 17).	Wind Power Plant (WPP) consisting of **Enercon E82 2.3 MW type IV** Wind Turbine Generators (WTG), with alternative settings equivalent to the "step function" defined by Hydro-Québec (Table 17).

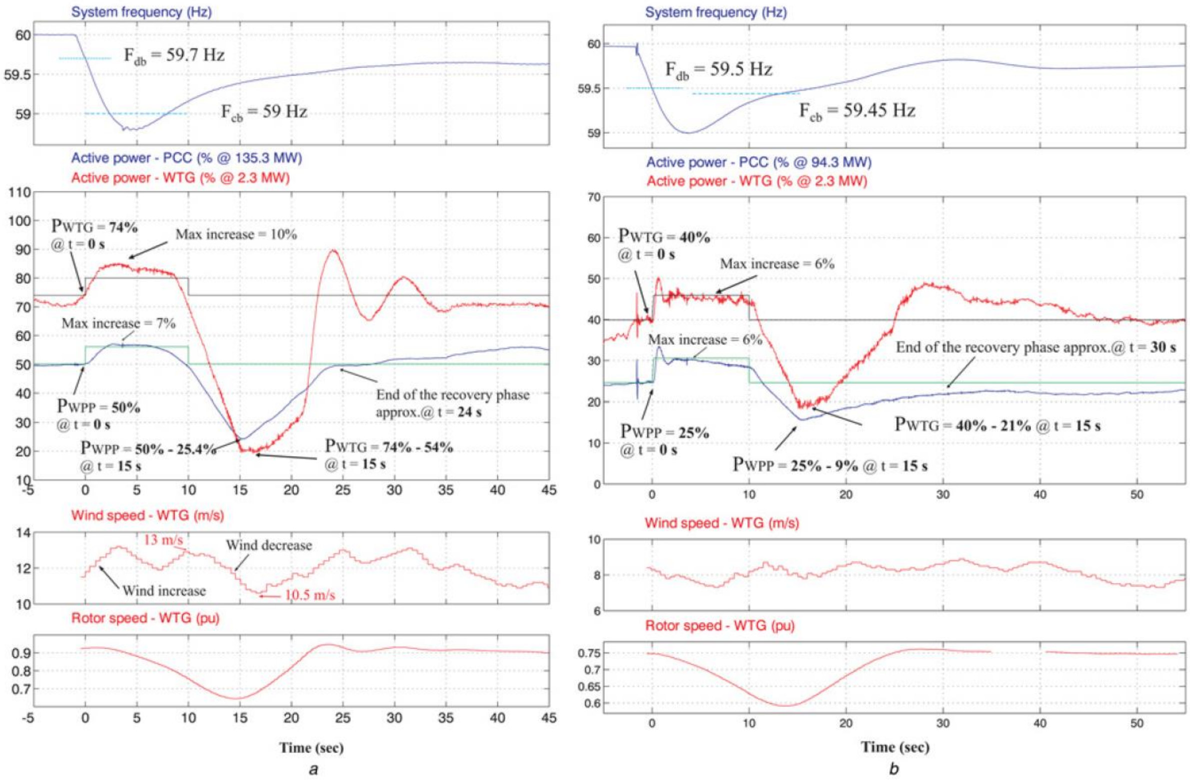
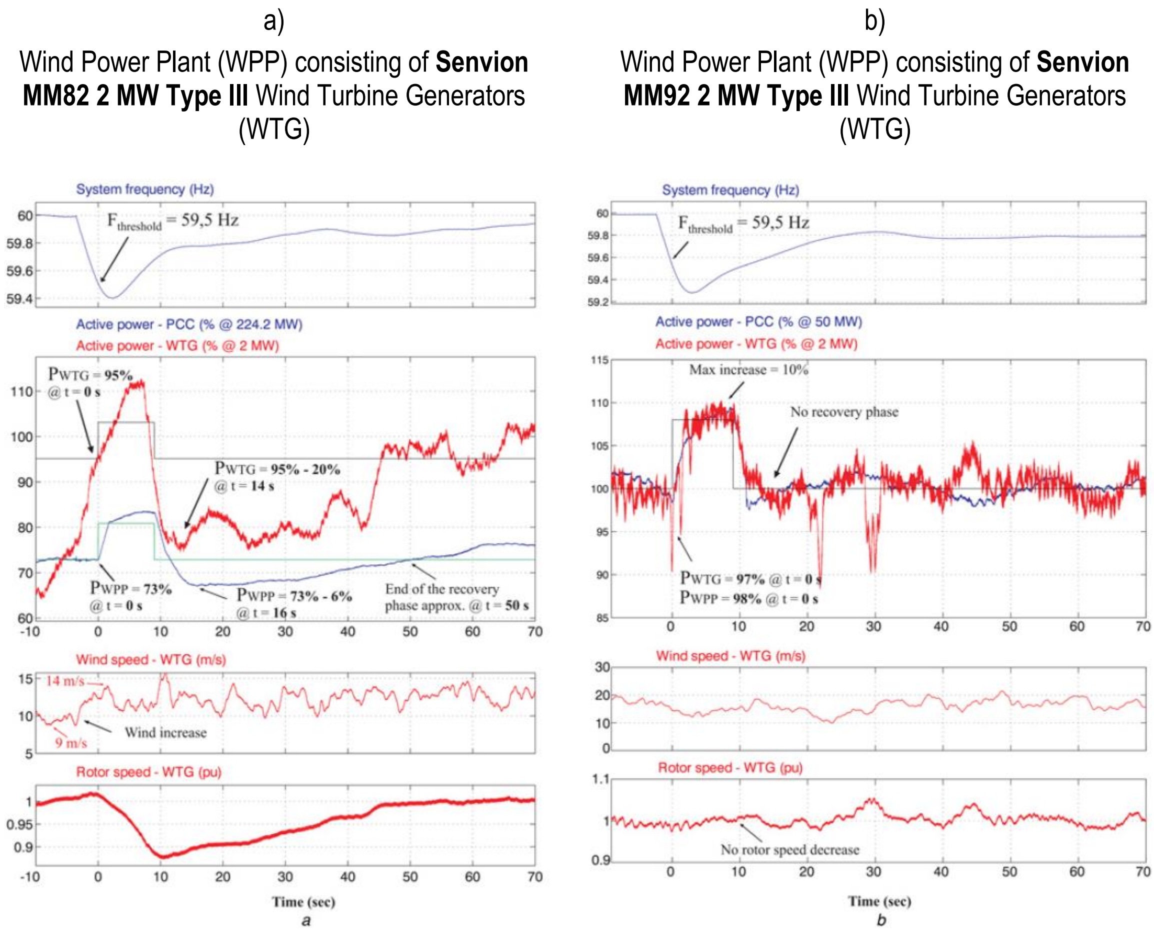


Figure 29 shows comparative results for Type III wind turbines, responding to real system frequency events in Hydro-Québec . In Figure 29 a) the individual wind turbine increases active power by ~17% of rated power, far beyond the required setting of 8%. This is most likely due to increasing wind speed during the rise period (from 9 to 14m/s). This response is smoothed across the wind farm, however, which achieves the required active power boost of 8% in 1.6 seconds, and eventually a maximum value of 10.5%. The boost period lasts for a duration of ~9 seconds. The power drop during the recovery phase reached 20% at the individual wind turbine, and 6% across the wind farm. The recovery phase lasted for a duration of ~40 seconds.

In Figure 29 b) shows alternative results for a wind farm operating at 100% of rated power prior to the event. In this situation, the emulated inertial response is delivered within several seconds, reaching 10% of rated power, and lasting for a duration of 9 seconds. There is no recovery period in this case, because the wind turbine can use pitch control to recover the energy expended in these high wind conditions.

Figure 29 – Type III wind turbines - Measured emulated inertia response in Hydro-Québec (two different events) [16]



On the basis of these field experiences, Hydro-Québec has translated the initial specifications for emulated inertial response into performance guidelines in the future grid code, pending approval [16, 96].

Researchers have noted that the characteristics of the emulated inertial response of these turbines has been tailored to the requirements of the Hydro-Québec system. Other system operators should conduct bespoke analysis to determine the optimal wind farm emulated inertial response for their power system [97, 98, 99, 100]. Wind power plants have the flexibility to adjust droop curve settings, inertia constants, and governor deadbands depending on system needs and requirements. Wind power can also respond to new designs like non-symmetric or non-linear droop curves, if desired [98].

A summary of the relevant findings from these studies includes:

- Emulated inertial responses from wind turbines of various kinds have been demonstrated to meet the specified requirements in the Hydro-Québec system. To meet Hydro-Québec 's specifications, manufacturers have designed turbines to provide an active power increase of ~6% of nominal rated capacity, responding within several seconds, and lasting for a duration of ~10 seconds. This is followed by a recovery period of ~15-40 seconds. The active power reduction in the recovery period can vary significantly, depending upon the wind speed. If the NEM elects to specify a Fast Frequency Response service, it would be helpful to be conscious of these design capabilities, to allow products presently on the market to participate (if these response characteristics are optimal for the NEM).
- The emulated inertial response can vary significantly at an individual turbine level, depending upon wind speed variability, but averaging across a wind farm appears to deliver a reliable response in the cases investigated. This means that validation testing procedures should involve measurements for the whole wind farm (testing of the response from individual turbines alone is not sufficient).
- Active power reduction during the recovery period can be significant under some conditions, depending upon the wind speed, and should be investigated at a power system level before specifying the preferred response characteristics, to ensure that wind turbines aren't likely to contribute to power system collapse during the recovery phase.

7.3 Ontario

Ontario Hydro also requires an emulated inertial response from wind turbines [94]. On-shore wind generation facilities that employ doubly-fed wind turbines or full converter-interfaced wind turbines are expected to have a capability to respond to a decline in the system frequency by temporarily boosting their active power output by recovering energy from the rotating blades (an "inertia emulation control" function). The required specifications are listed in Table 18.

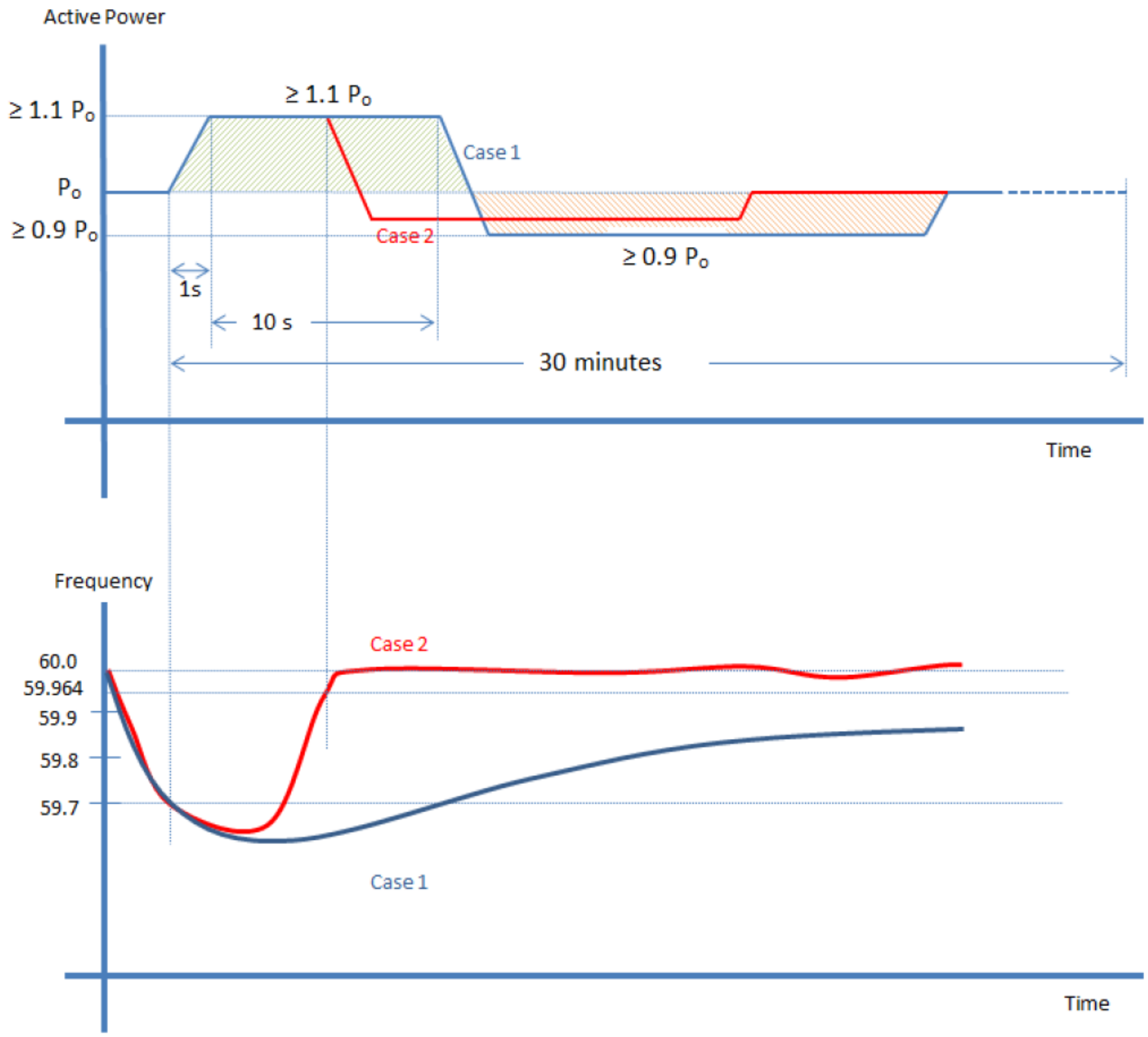
Table 18 - Specifications for Emulated Inertia Function in Ontario [101, 102]

Specification Type	Requirement
Minimum duration	10 seconds
Power contribution	At least 10% of pre-trigger active power
Frequency threshold	-0.3 Hz

Specification Type	Requirement
Maximum response delay	1 second
Minimum output for availability	25%
Maximum subsequent power drop below pre-disturbance	5%

The requirements specify that "the rate of energy withdrawn from the system during active power recovery must in general be less than the rate of energy injected into the system during the active power boost" [102]. An illustration of a response that meets these requirements (for two different trigger events) is shown in Figure 30.

Figure 30 - Inertia Emulation Requirement in Ontario [102]



Wind farms may connect without inertia emulation control capability (if it is not commercially available), but in that case the system operator reserves the right to ask for this applicant to install this function in future, when it is available for the proposed type of turbine [103, 104]. Some projects have included this capability [104, 105], while others have not [103]. Retrofit of this capability at a later date is likely to be considerably more expensive than including it during the initial installation.

The system operator notes that solar generation does not have a similar store of energy, so active power increases are not yet required from solar installations, but this may change as technology evolves [102].

7.4 Brazil

Brazil has ~6GW of wind installed at present, accounting for around 4.5% of capacity. Projections predict this growing to 17GW by 2019 [100]. In anticipation of this growth, the system operator (Operador Nacional do Sistema Elétrico, ONS) is in the process of changing the Brazilian grid code, and has added to auction rules [106], the requirement that all wind plants provide a emulated inertial response of at least 10% of their installed capacity during under frequency events [100].

7.5 New Zealand

Transpower modelled the emulation of inertia by wind farms, and found that it could lead to an improvement in the RoCoF, and the frequency nadir [47]. For example, during the North Island summer peak, adding emulated inertia was found to decrease the RoCoF from 0.45 Hz/s to 0.22 Hz/s (at 1 second following the contingency event). The study recommended a trial to determine the practical feasibility of emulated inertia from wind farms.

7.6 Conclusions

An emulated/synthetic inertial response from wind turbines is a relatively new technology. This technology uses the kinetic energy in the spinning blades to provide a brief active power “boost” when a frequency disturbance is detected. This is a type of FFR service, and is technically distinct from a synchronous inertial response.

Only a few power systems currently require emulated/synthetic inertial capabilities from wind turbines; this review found mandatory requirements in Hydro-Québec, Ontario and Brazil. Of these, only Hydro-Québec appears to have any significant practical experience with the delivery of this service from wind turbines.

In Hydro-Québec, wind turbines have been shown to successfully provide an emulated inertial response as specified, in response to real contingency events. They show a response within 1-2 seconds, with an active power increase of 6-10% of rated capacity, which extends for about 10 seconds. Wind turbines of various types (from a number of different manufacturers) have been shown to successfully delivery this response.

The initial active power "boost" is followed by a "recovery period", where the wind turbines experience a reduction in active power, to reaccelerate the turbine blades and prevent stalling. During the recovery period, the active power from the wind turbine can be as much as 30% below the pre-contingency level, and can extend for a duration as long as 40 seconds.

The nature of the active power response and the characteristics of the recovery period depend strongly upon the prevailing wind speed at the time of the event. This creates complexities for the power system operator in anticipating the response that will be delivered following a contingency event.

7.6.1 Insights for the NEM

7.6.1.1 Simulations for the NEM

The emulated/synthetic inertial response from wind turbines is very flexible, within physical limitations. There is potential to request that manufacturers produce the specific capabilities from wind turbines that would be most beneficial to the NEM. Detailed dynamic frequency simulations would be required to determine the optimal response characteristics, to suit the NEM. The typical response characteristics of wind turbines now on the market were mostly designed to suit the Hydro-Québec system, and could provide a suitable starting point for these investigations, but should not be assumed to be the only possible response.

In any modelling, particular care should be taken to represent the recovery period, and ensure that the primary frequency response (governor response) of other units can compensate for this active power reduction. If this is done poorly, the emulated/synthetic inertial response may successfully arrest the initial frequency decline, but lead to cascading system collapse during the recovery period. In general, a larger initial active power injection for a longer duration will require a longer and deeper recovery period (to recover the required energy).

7.6.1.2 Emulated/synthetic inertial capabilities

An emulated/synthetic inertial response from wind turbines (a type of FFR) could prove to be an important and cost-effective component for managing high RoCoF in the future. Wind turbines installed today are expected to remain in operation for 10-30 years, and retrofitting, calibrating and verifying this capability later could be considerably more expensive than including it during the initial design and commissioning (when the OEM is already engaged in the testing and verification process). This suggests that it could be prudent to encourage the inclusion of an emulated/synthetic inertial response capability in new entrant wind farms, particularly in South Australia. Wind farms could include the *capability*, but not necessarily deliver the response, at this stage. This would ensure they are available to deliver this service when it is required in future.

A mandatory requirement for emulated/synthetic inertial capabilities has been introduced in Hydro-Québec and Ontario, and has not halted investment in new wind generation, suggesting that it does not pose an insurmountable barrier to entry.

8 THE DESIGN OF NEW FREQUENCY CONTROL ANCILLARY SERVICES

This section explores the changes in frequency control ancillary services being implemented or considered in other jurisdictions. The focus is on the manner in which the services have been specified, the motivations for their introduction and any cost-benefit studies undertaken, as well as the work program leading to their implementation.

8.1 EirGrid/SONI (Ireland/Northern Ireland)

One of the key workstreams in the DS3 Program (introduced in Section 3.1.1) is the System Services workstream [107]. This program aims to transform Ancillary Services, to put in place the appropriate structure, level and type of services to ensure that the system can operate securely with up to a 75% instantaneous penetration of non-synchronous renewable generation [107]. The CER/UR found that there is clear evidence that enhanced system services are required in order to maintain a secure and reliable electricity system under conditions of high wind penetration [108].

8.1.1 Program of work

Significant milestones in this program of work are outlined in Table 19, and detailed further in the following sections.

Table 19 - Milestones in the System Services workstream

Date	Milestone
June 2010	EirGrid/SONI Studies on Facilitation of Renewables
July 2011	EirGrid/SONI report on Ensuring a Secure, Reliable and Efficient Power System
Sept 2011	EirGrid/SONI formally commenced the DS3 Project
Dec 2013	Technical Definitions for System Services (Decision)
Dec 2014	Procurement Design for System Services (Decision)
Q1 2015	Commenced Detailed Design Phase
1 Oct 2016	Go-live of Interim Arrangements (new ancillary services procured with regulated tariffs)
Q1 2017	First Auction run
Jan – Jul 2017	Proposed duration of Qualification Trials (demonstrate new technology capabilities)
1 Oct 2017	Go-live of Enduring Arrangements (competitive tender for procurement of some services)

The CER/UR decided to focus first on the technical design of ancillary services. This was then followed by economic analysis (including modelling to determine the value of system services, the volumes required, and options for procurement mechanisms), eventually leading to decisions on commercial aspects [108].

Stakeholders have expressed "considerable concern" at the length of time taken to reform ancillary services in Ireland/Northern Ireland [108]. For example, in 2012 EirGrid/SONI invested significant efforts in developing detailed recommendations on system services, including extensive stakeholder consultation [109, 110, 111]. The SEM Committee then undertook their own assessment and consultation process, before making a decision on technical definitions in December 2013 [108], and on procurement design in December 2014 [112]. The time taken was attributed to the considerable amount of work required to design robust solutions. AEMO should be mindful of managing stakeholder expectations around the significant time involved in developing new ancillary services, and seek streamlined approaches to undertake stakeholder consultation collaboratively with the AEMC.

Ireland/Northern Ireland are very active at present in the Detailed Design Phase of their new ancillary services framework, having recently published reports on auction design [113, 114], estimating the portfolio capability for each ancillary service [115], contracting arrangements [116], service specification [117], regulated tariffs and tariff methodologies [118, 119], payment scalars [120, 121], procurement options [122, 112, 123], and so on. There are likely to be ongoing lessons available to AEMO as this process evolves, particularly as the NEM moves further along the ancillary services design path.

8.1.2 Overview of system services (Technical Definitions)

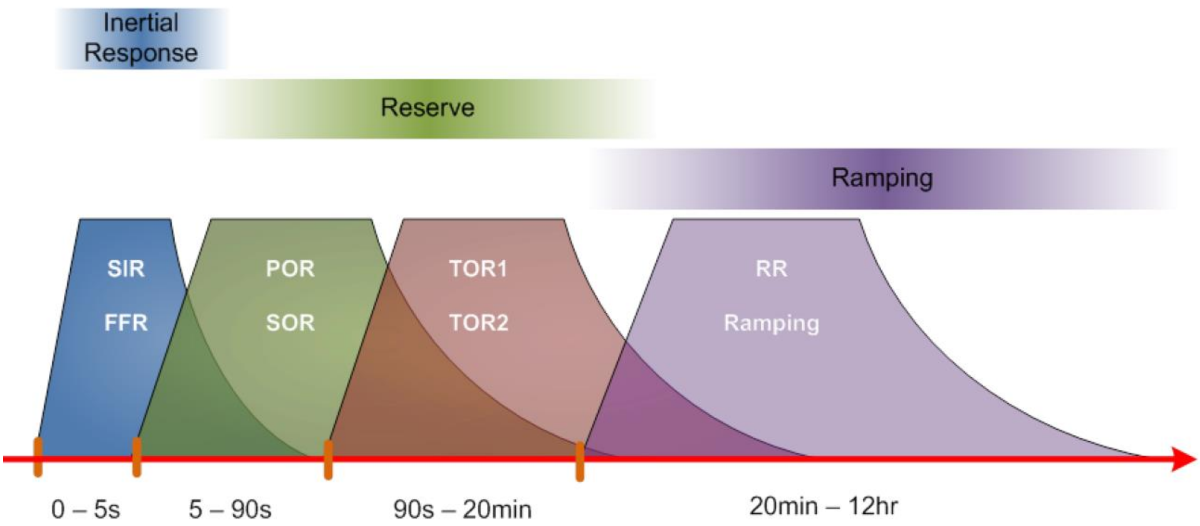
The suite of frequency control ancillary services to be implemented in EirGrid/SONI are listed in Table 20, and illustrated in Figure 31. Several new ancillary services related to voltage control are also being introduced [108]; these are not discussed in this review (which focuses on frequency control).

Table 20 – Frequency Control System Services in Ireland/Northern Ireland [108]

Acronym	Title	Response Time
	New Services:	
SIR	Synchronous Inertial Response	Instantaneous
FFR	Fast Frequency Response	2 seconds, sustained for 8 seconds
RM1	Ramping Margin 1 Hour	1 hour, sustained for 2 hours
RM3	Ramping Margin 3 Hour	3 hours, sustained for 5 hours

Acronym	Title	Response Time
RM8	Ramping Margin 8 Hour	8 hours
FPFAPR	Fast Post-Fault Active Power Recovery	250 milliseconds to return to 90% active power post-fault
	Existing Services:	
POR	Primary Operating Reserve	5 – 15 seconds (delivered at the frequency nadir)
SOR	Secondary Operating Reserve	15 seconds, sustained for 90 seconds
TOR1	Tertiary Operating Reserve 1	90 seconds, sustained for 5 minutes
TOR2	Tertiary Operating Reserve 2	5 minutes, sustained for 20 minutes
RRD	Replacement Reserve (De-synchronised)	20 minutes, sustained for 1 hour
RRS	Replacement Reserve (Synchronised)	20 minutes, sustained for 1 hour

Figure 31 - Frequency Control Services [108]



The services of most relevance to the NEM are discussed further in the following sections.

8.1.3 Synchronous Inertial Response (SIR)

Synchronous Inertial Response (SIR) is a new service. With increasing non-synchronous generation this response becomes scarce, and therefore it will be explicitly procured as a system service [108].

SIR is described as the response in terms of active power output and synchronising torque that a unit can provide following disturbances, immediately available from synchronous generators, synchronous condensers and some synchronous demand loads (when synchronised) because of the nature of synchronous machines [108].

A key concern appears to have been to create incentives for units to provide synchronous inertia with the capability of operating at low MW outputs, to allow the system to accommodate higher levels of non-synchronous generation. To achieve this, the SIR service is defined as the kinetic energy (at nominal frequency) of the unit[8], multiplied by the SIR Factor (SIRF). The SIRF of a synchronous generator is the ratio of the kinetic energy (at nominal frequency) to the lowest sustainable MW output at which the unit can operate at while providing reactive power control [108]. The SIRF has a minimum threshold of 15 seconds and a maximum threshold of 45 seconds. The SIRF for a synchronous condenser or a synchronous demand load that can provide reactive power control is set at 45 seconds. The SIR Volume is calculated by the following formula [108]:

$$\text{SIR Volume} = \text{Stored Kinetic Energy } \times (\text{SIRF} - 15) \times \text{Unit Status}$$

Stakeholders found the thresholds of 15 seconds and 45 seconds to be controversial, since these mean that not all inertia in the system is remunerated. The 15 second limit means that some units that cannot provide inertia at a low MW output are excluded. The CER/UR felt that this was appropriate, since inertia from these units "does not provide adequate additional value for the consumer relative to the status quo", and that such payments would "weaken the economic signals to generators to provide enhanced capability" [108].

Similarly, the 45 second limit places an upper limit on the SIR volume for which a provider is remunerated. This was justified on the basis that there is a limit on the value to the system of a single unit providing additional inertia beyond a certain point, and the incremental additional inertia from other units would provide more value to the consumer in terms of system resilience [108]. The 45 second value was justified on the basis of EirGrid/SONI's technical analysis [108].

The provision of emulated inertia is considered to be distinct from the SIR service (in that such providers are not synchronized) [108]. Flywheels, in particular, were noted to be a fast responding alternative that could potentially be considered in future, but are excluded in the present definition unless they are synchronized.

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[8] Dispatchable synchronous generator, dispatchable synchronous condenser or dispatchable synchronous demand load.

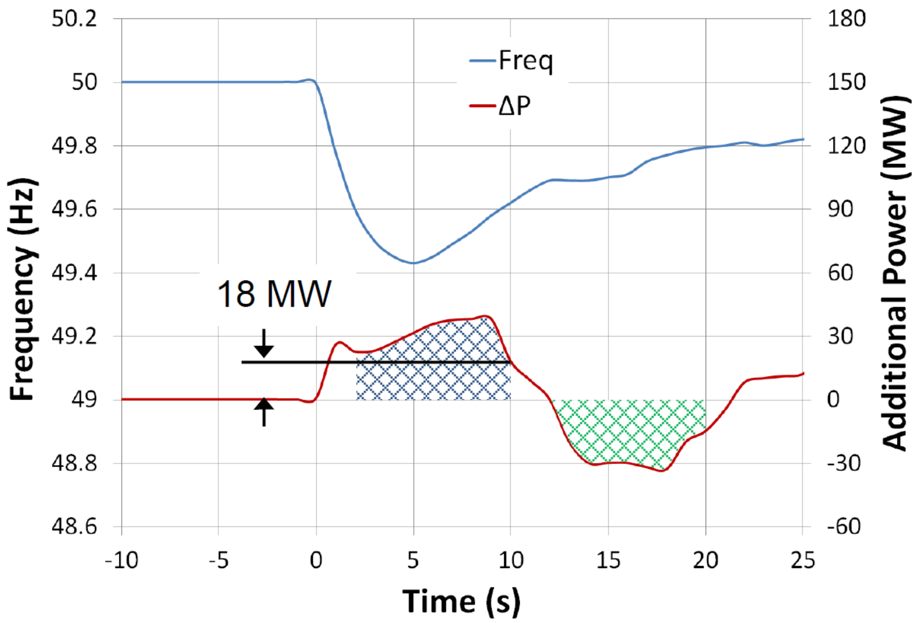
8.1.4 Fast Frequency Response (FFR)

FFR is a new service that provides a MW response faster than the existing Primary Operating Reserve times and may, in the event of a sudden power imbalance, increase the time to reach the frequency nadir and mitigate the RoCoF in the same period, thus lessening the extent of the frequency transient [108].

FFR is defined as the additional increase in MW output from a generator or reduction in demand following a frequency event that is available within two seconds of the start of the event and is sustained for at least eight seconds.

A key concern appears to have been the need to specify limitations on the "recovery period" for emulated inertia provided by wind generation. Therefore, the FFR definition specifies that the extra energy provided in the two to ten second timeframe by the increase in MW output must be greater than any loss of energy in the 10 to 20 second timeframe due to a reduction in MW output below the initial MW output (i.e. the hatched blue area must be greater than the hatched green area in Figure 32).

Figure 32 - Fast Frequency Response [108]



The FFR volume is measured as the additional MW Output that can be provided when connected. Providers may deliver both SIR and FFR, if they have the technical capability to deliver both [108].

Stakeholders suggested a pay-for-performance type approach that would reward providers that deliver the FFR faster than two seconds [108]. The CER/UR originally decided that this was not required (based upon analysis by EirGrid/SONI), and that it may reduce market participation by redistributing revenue from slower to faster FFR providers (effectively excluding providers close to the two second threshold), and result in higher costs to consumers than is required [108]. However, the SEM Committee later indicated that "scalars" would be applied to payments for services, which could incorporate higher payments for faster delivery, where this provides increased value to consumers [112]. EirGrid/SONI have now indicated an intention to apply a scalar to the FFR service for faster response, as well as for enhanced delivery [120].

8.1.5 Fast Post-Fault Active Power Recovery (FPFAPR)

During and following a voltage disturbance (such as a transmission fault), non-synchronous generators enter fault-ride-through mode, and in this phase provide limited active power to the system. This can significantly increase the effective size of a frequency disturbance, particularly if a large number of generators do not recover their MW output sufficiently rapidly.

To assist in addressing this, Ireland/Northern Ireland are introducing a new service to allow explicit procurement of a service to rapidly recover MW output following a voltage disturbance.

Fast Post-Fault Active Power Recovery is defined as having been provided when, for any fault disturbance that is cleared within 900 ms, a plant that is exporting active power to the system recovers its active power to at least 90% of its pre-fault value within 250 ms of the voltage recovering to at least 90% of its pre-fault value [108]. The generator must remain connected to the system for at least 15 minutes following the fault. The FPFAPR volume is based on MW output prior to the event [108].

It is interesting that the CER/UR decided to introduce this as a paid service to be procured, rather than as a more stringent mandatory fault-ride-through requirement for all plant in the Grid Code. This is perhaps to allow the System Operator to procure the service dynamically in the volumes required (based upon system conditions), and to avoid creating onerous Grid Code requirements that could create barrier to entry for some technologies (thereby increasing costs to consumers).

8.1.6 Ramping Margin Services

Ireland/Northern Ireland have introduced three new "Ramping Margin" services, designed to manage variability and uncertainty in a power system with higher levels of variable generation. Analysis by EirGrid/SONI showed that future generating portfolios were not likely to have adequate ramping capability [108, 110], and therefore new services should be defined.

Ramping Margin is defined as the guaranteed margin that a unit provides for a specific time horizon and duration. There are horizons of one, three and eight hours with associated sustain durations of two, five and eight hours respectively [108]. These are not mutually exclusive; a provider can receive payments for two or three of these services simultaneously [108].

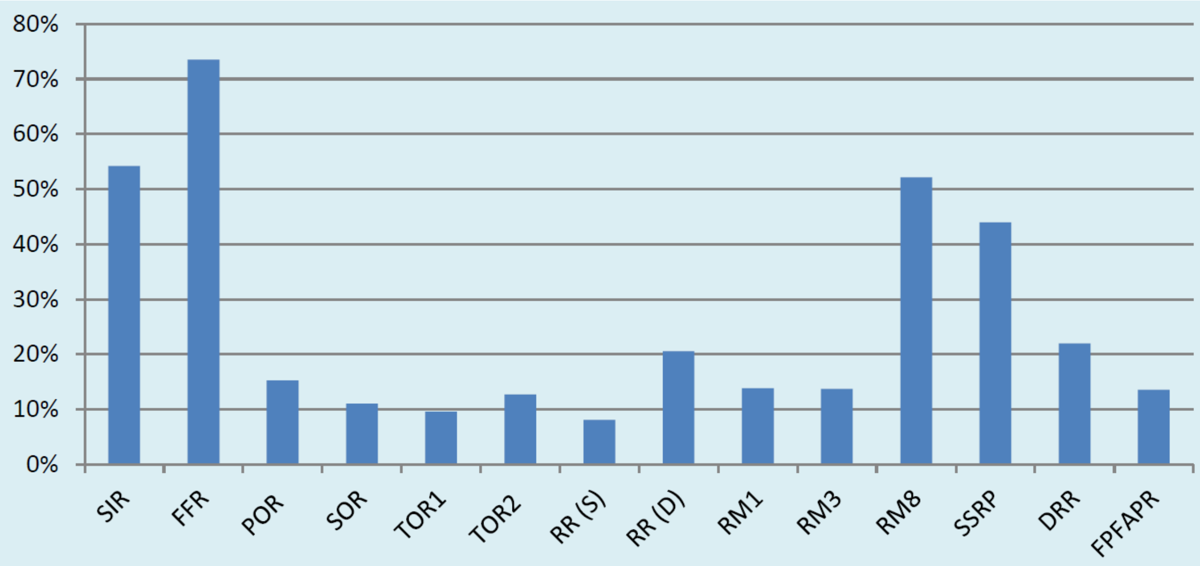
The defined services only involve ramping up; EirGrid/SONI's analysis indicated that a ramping-down product was not currently required [108].

These services are not related to the management of high RoCoF. However, they may be of interest and relevance to the NEM, if analysis indicates that a shortfall in ramping capability is likely in future. This should be examined by AEMO.

8.1.7 Analysis on future power system requirements

EirGrid/SONI conducted analysis to project the future volume requirements for each service, with results illustrated in Figure 33. Increased capability for SIR and FFR are identified as particular system needs. This suggests, noting the caveats discussed above, that there is a significant volume requirement for new SIR and FFR capability (either from new entrants or improved performance from existing units) [112]. Note that SIR is not the MW of synchronous capacity installed, but is instead defined via factors, as described in Section 8.1.3.

Figure 33 - Required increase in installed capability to achieve SNSP of 75% in 2020



8.1.8 Commercial arrangements

The new arrangements will be implemented in a phased approach. An interim set of regulated tariffs will apply from 1 Oct 2016 to 30 Sept 2017, allowing EirGrid/SONI to procure system services until an enduring competitive process has been fully designed and implemented [112]. The interim phase will also provide greater information on the capabilities of the existing portfolio to provide the specified services, and will establish a reference price around which a competitive process can operate (or provide guideline clarify on the prices for services for which a competitive process is not possible) [112].

A pre-qualification process will be used to establish the current system services capability in the portfolio (providing insight into which services have insufficient competition), and act as a filtering process to prevent speculative projects from distorting prices in the auction process [112].

Following the interim phase, for services where there is sufficient competition, an auction will be run in 2017 [112]. For services where there is insufficient competition for a competitive auction, enduring tariffs for each service will be set for five years, on one-year contracts [112].

Long-term contracts (1-15 years, or up to 20 years with approval) will be issued through the auction for new investment, and one-year contracts will be issued for existing capability [112]. This approach was selected to provide investors with revenue certainty.

The payment basis for all services will be on an "availability" basis, such that a provider with a system services contract will be paid for the volume of the service that they actually provided or made available in that trading period, regardless of the real-time requirement for that service. This approach was felt to provide a suitable balance between providing revenue and volume certainty to investors, while still incentivizing appropriate interaction with the energy market and provision of greatest value to customers [112]. Units must bid into the energy market in such a way that they ensure they are dispatched (so that they can provide the required services).

"Scalars" will be applied to the unit prices for each service, to reduce the level of payment to service providers where the value is not being delivered to the consumer, or to increase the level of payment for providers delivering additional value [112]. These are defined around issues such as performance (rewards good performance), scarcity (create marginal incentives for provision during periods or in locations of scarcity), and by product (where a provider can deliver a service in a faster time fame, and thereby deliver more value to consumers) [112]. A significant amount of effort has been expended during the Detailed Design Phase in the development of these scalars, including recently released detailed consulting work [121].

8.1.9 Qualification Trial Process

One focus of the System Services workstream is to facilitate the provision of ancillary services from emerging technologies, while ensuring power system resilience, understanding that in some cases robust and efficient measurement approaches to monitor performance do not exist, or are not yet fully proven [107].

To address this, EirGrid/SONI have recently proposed a "Qualification Trial Process", to allow emerging technologies to gain access to the Central Procurement Process for ancillary services, while managing system security prudently, and only contracting for what can be robustly measured [107].

EirGrid/SONI have proposed two key elements for the Qualification Trial Process [107]:

1) Provenability – Proof of reliable delivery of service
2) Measurability – Proof of the mechanism to monitor the delivery of that service.

EirGrid/SONI will also use the Qualification Trial Process to inform the development of new codes and standards for new technologies, processes and procedures for commissioning and testing of new technologies, and the design of performance monitoring arrangements [107].

The Qualification Trial Process will involve conducting trials, commencing in Q1 2017. Wind and demand-side technologies will form a particular focus (due to the high levels of deployment of these technologies in Ireland and Northern Ireland), but will also include "other technologies" such as energy storage and flywheels [107].

For the Provenability Trials, EirGrid/SONI have proposed procuring 40MW of wind, 20MW of demand-side, and 20MW of "other technologies", from a range of service providers [107]. The selected providers will need to operate under real system conditions, responding to 5 events during the trial period (6 months, commencing Q1 2017).

For the Measurability Trials, the focus is particularly on the fast-acting ancillary services, including Fast Frequency Response (FFR). Participants will need to provide evidence of performance in one event during the trial period (3 months, commencing Q1 2017).

The results of these trials are likely to be of significant value to AEMO, and should be examined for key lessons as they become available.

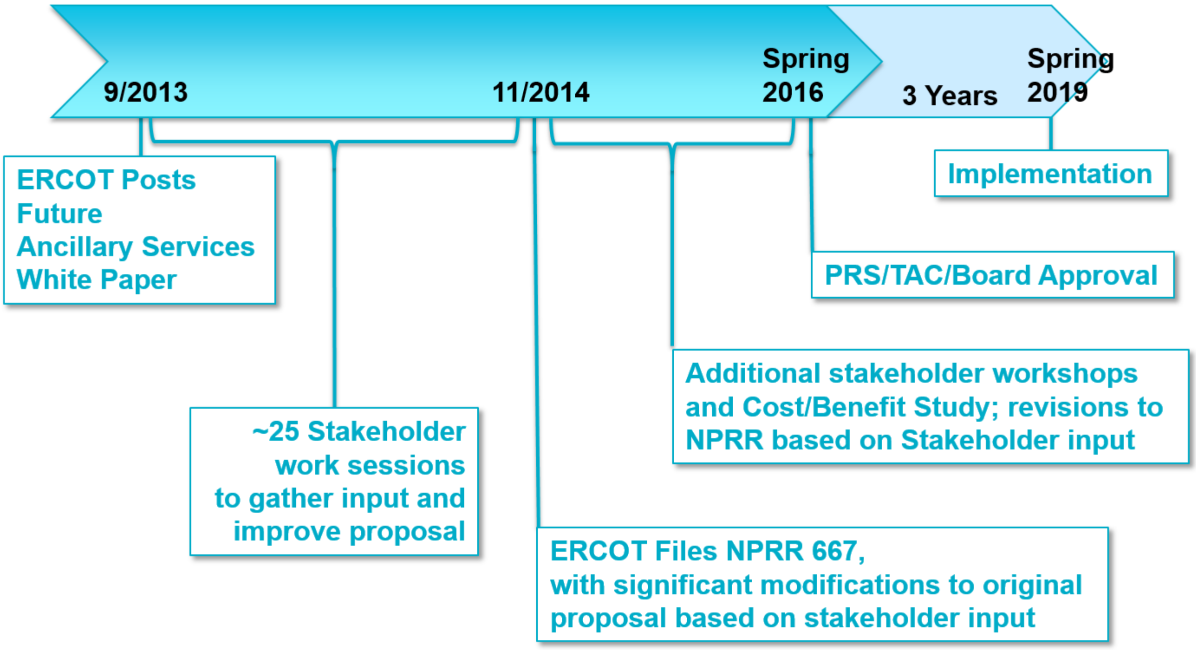
8.2 ERCOT (Texas)

8.2.1 Program of work

ERCOT began exploring options to improve frequency control ancillary services in 2012 [3], with a range of motivations, including the integration of new types of resources that bring new challenges and capabilities. In late 2013, they proposed a new suite of frequency control ancillary services [3]. As illustrated in Figure 34, this was followed by extensive stakeholder workshops. ERCOT submitted a formal proposal to the Technical Advisory Committee (TAC) and Protocol Revision Subcommittee (PRS) in late 2014. The TAC makes policy recommendations to the ERCOT Board of Directors, and the PRS is accountable to the TAC.

Demonstrating the cost-benefits of the proposal was a significant area of focus, with ERCOT commissioning the Brattle Group to undertake a significant modelling exercise throughout 2015 [46]. This study is discussed further below.

Figure 34 - Timeline of work [124]



After extensive dialogue with Market Participants, especially including the retailers (who carry and must pay for their Ancillary Service responsibilities) ERCOT agreed to an "adjustment period" to allow retailers to adapt forward contracts and adequately hedge their future obligations. Accordingly, ERCOT proposed implementation at a date three years from the date of approval by the ERCOT Board [125].

Table 21 - Timeline of events

Date	**Milestones** [126]
Mid-2012	ERCOT began discussing new ancillary services [3]
27th September 2013	ERCOT published concept paper on future ancillary services [3]
18th November 2014	ERCOT submitted proposal for ancillary services redesign (NPRR667) [127]
11th November 2014	Proposal tabled at PRS. Discussion at meetings and workshops: • Reliability need for ancillary services redesign • Project costs associated with implementation • Potential for smaller adjustments to achieve benefits with minimal impacts
21st December 2015	ERCOT published Brattle Group study on cost-benefit analysis [46]
12th May 2016	PRS voted to reject the ancillary services redesign proposal.
18th May 2016	ERCOT filed an appeal of the PRS decision to TAC.
26th May 2016	TAC voted to reject the ERCOT appeal.

As outlined in Table 21, the proposal was recently rejected by the TAC and PRS. The decision to reject the proposal cited the following concerns [126, 128, 129]:

- ***No reliability need*** – ERCOT has not demonstrated a current nor future reliability need for new Ancillary Services. ERCOT was seen to have delivered "exceptional performance" from a reliability perspective, and this has been observed to be improving over time, despite significant growth in intermittent resources.
- ***Liquidity concerns*** – Market participants have concerns about market liquidity for new Ancillary Services, given the unbundling of the services into a larger number of categories.
- ***Focus on alternatives*** – Market participants would prefer to see ERCOT focus on identified reliability needs and alternatives to the proposal, which ERCOT was not willing to do so long as this proposal was undecided.
- ***Implementation costs*** – Several market participants believed ERCOT's estimated implementation cost for the changes of $12 million to $15 million was too low, and also that ERCOT did not adequately address the costs and funding for the new services.
- ***Incremental changes preferred*** – Some market participants felt that incremental changes would be possible, to deliver the same value with a lower implementation cost.

It does not appear that the proposal was rejected for any insurmountable technical reasons.

ERCOT has indicated that they continue to believe in the concepts outlined in the proposed future ancillary services design, and intend to continue their work with stakeholders to plan for future ancillary services needs [128].

Although the proposed ancillary services changes were rejected, the work done to design this framework may offer valuable insights to AEMO, and is therefore outlined further below.

8.2.2 Specification of proposed future ancillary services

The future ancillary services proposed by ERCOT are summarized in Table 22 and Figure 35, with the services most relevant to the NEM discussed further in the sections below. The proposal is compared with the existing set of ancillary services in Figure 36.

Table 22 – Frequency Control System Services in ERCOT [3, 86]

Acronym	Title	Response Time
SIR	Synchronous Inertial Response	Instantaneous
FFR1	Fast Frequency Response	Full response in 0.5 seconds, sustain for 10 minutes
FFR2	Fast Frequency Response	Full response in 0.5 seconds, sustain as long as needed
PFR	Primary Frequency Response	Commence response in 1.5 seconds, full response in 16 seconds, sustain for 1 hour
Reg	Regulating Reserve	Commence response in 4-6 seconds, full response in 5 minutes, sustain for 10 minutes
CRS	Contingency Reserve Service	Commence response in 5 minutes, full response in 10 minutes, sustain for 1 hour

Figure 35 - Future Ancillary Services proposed in ERCOT [3]

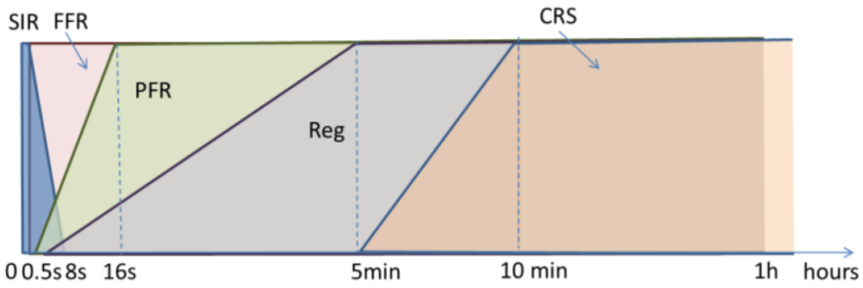
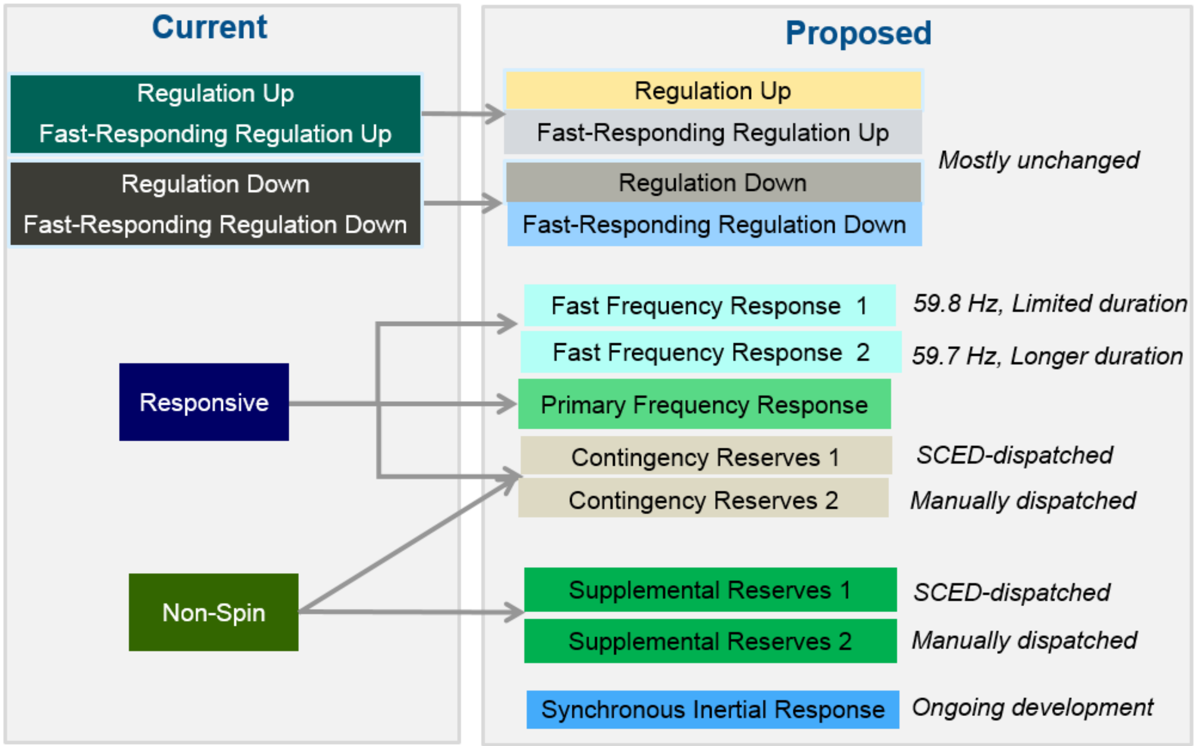


Figure 36 - Future Ancillary Services proposed in ERCOT [124]

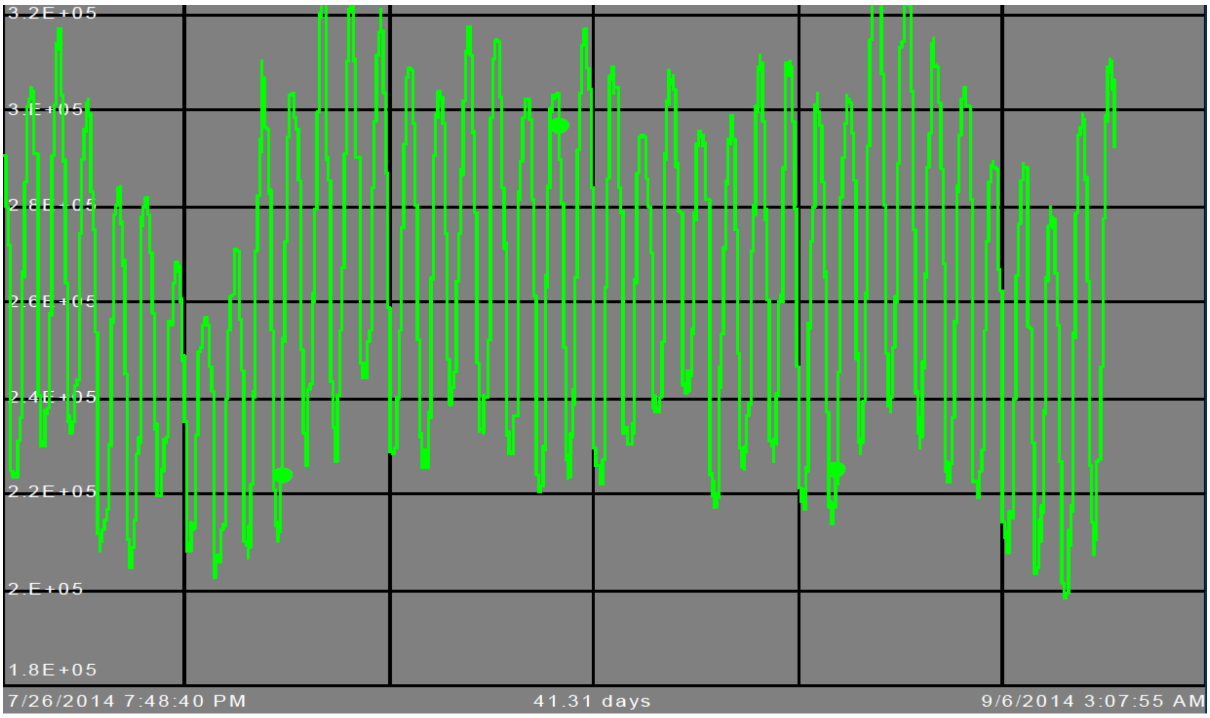


8.2.3 Synchronous Inertial Response (SIR)

ERCOT define the Synchronous Inertial Response (SIR) as the instantaneous response from synchronous machines following disturbances [3]. It is calculated as the stored kinetic energy (at nominal frequency) that is extracted from the rotating mass of a synchronous machine following an imbalance in a power system [3]. They note that the inertia response that a synchronous machine can provide is independent of the machine's power output. They also specifically note that emulated inertia (a control action in response to falling system frequency) is not equivalent to synchronous machine inertia (a natural response of synchronous machines to a generator trip), but that emulated inertia will improve RoCoF and help to arrest system frequency decay [3].

The SIR service was not proposed to be implemented as a part of the NPRR667 proposal, but was noted as the focus of ongoing development [125]. This appears to be because of the view that there is sufficient SIR available "naturally", which precludes the need for an explicit procurement of this service [86]. Therefore, ERCOT considered SIR on a different time track and implementation sequence from the other services [3]. Instead of promoting a market solution for SIR, ERCOT has developed a real time calculator to determine the amount of SIR required for each hour, as illustrated in Figure 37 [3, 130]. The ERCOT optimization engine seeks a resource commitment solution that minimizes resource costs, while simultaneously satisfying the requirements for a minimum amount of SIR (the SIR constraint) [3].

Figure 37 – Example output from ERCOT real time calculator for SIR (H*MVA) [130]



ERCOT notes that there is no opportunity cost to a generator for providing SIR (an inertia response is not provided instead of anything else, such as energy), which is somewhat different to other types of frequency control services (which require "headroom" to deliver the availability for the service) [3].

ERCOT proposed the possibility of creating a SIR market via an administrative sloped SIR demand curve, coupled with SIR offers at a price of zero [3]. The resulting intersection of the SIR supply and demand curve would then determine the clearing price for the service. The clearing price would be paid to all resources providing the service [3].

8.2.4 Fast Frequency Response (FFR) and Primary Frequency Response (PFR)

ERCOT define FFR as a MW response faster than the existing primary frequency response (PFR), with full response delivered within 0.5 seconds (30 cycles), and sustained for at least 10 minutes. It acts to increase the time to reach the frequency nadir, and mitigates RoCoF [3].

ERCOT split the FFR into two types [127]:

- FFR1 – Sustain a full response for at least ten minutes and, once recalled, restore full capability within 15 minutes. Responds at a higher frequency set-point.
- FFR2 – Sustain a full response until receiving an ERCOT recall instruction or until the ancillary service responsibility expires, whichever occurs first, and, once recalled, restore full FFRS Ancillary Service Resource Responsibility within 180 minutes. Responds at a lower frequency threshold.

Notably, the requirement to sustain active power for 10 minutes to supply FFR effectively excludes provision of this service from emulated inertia from wind turbines. It is unclear why ERCOT has specified the service in this way, excluding this important resource. Instead, a key focus appears to have been specification that is inclusive of load resources [86].

Given the FFR definition in this manner (with a sustain duration of 10 minutes), ERCOT notes that FFR and primary frequency response (PFR) will be highly interdependent, and the needs will vary depending upon system condition [3]. PFR is defined in ERCOT as the response of Governors (or Governor-like action), generally delivered completely within 12-14 seconds. The full proportional response must be delivered within 16 seconds, and sustained for an additional 30 seconds [3]. Again, it is unclear why ERCOT felt it was necessary to design services that overlapped in timeframe. In general, non-overlapping services (where the overlap is defined by the timescale of full deployment) provide the most efficient delivery [131].

Because of the interdependent relationship and substitution capability between PFR and FFR, ERCOT proposed to treat the FFR and PFR services as a "single market". They proposed to determine the total requirement for the sum of FFR and PFR services for each Operating Hour and procure in the day ahead market an amount of FFR and PFR capacity that satisfies the total requirement [3]. This would incorporate a minimum requirement for each of FFR and PFR, when necessary to ensure acceptable system response.

Up to 1400 MW of reserve currently procured from load resources in ERCOT could satisfy FFR characteristics [3], giving confidence in the potential for load response to provide this service.

ERCOT note that FFR cannot completely replace system inertia [3].

ERCOT has a requirement that all units capable of governor response have their governors in service; however, units that do not have a PFR service responsibility are not required to reserve capacity for governor action and may be allowed to have a larger frequency dead-band [3].

8.2.5 Regulation

ERCOT proposed to create both up and down Fast Responding Regulation Services (FRRS). As defined at present, regulation services are able to respond to ERCOT signals within five seconds [86]. The new fast resources will respond to frequency fluctuations on the system within one second, and will rely both on internal triggers and ERCOT dispatch instructions [86].

8.2.6 Cost-Benefit analysis

ERCOT currently spends ~US$500 million annually on frequency control ancillary services, and the cost to implement the proposed changes was estimated at US$12-15 million [132].

ERCOT commissioned The Brattle Group to evaluate the economic benefits of the proposed Future Ancillary Services design [46, 133]. The report found that it offers economic benefits on the order of 10 times the implementation costs, will improve system reliability, and will also provide greater flexibility for meeting reliability needs as system conditions and resource capabilities evolve [46, 133]. The authors found that the two essential features of the new design—unbundling of services and fine-tuning of hourly requirements to system conditions—represent "good market design" in that they increase the possible ways to meet reliability objectives, and they avoid procuring more reserves than necessary.

To assess the economic benefits, the production costs of meeting ancillary services requirements were compared with to the current design. Requirements depended upon system conditions, simulated in PLEXOS across a range of future scenarios. The production cost impacts of holding reserves were examined by analyzing two separate and additive components [46, 133]:

1) Day-ahead energy opportunity costs, considering expected real-time prices as modeled in PLEXOS; and
2) Real-time option value foregone, considering the volatility of real-time prices around the expected value. This was estimated based on analysis of historical data.

After combining day-ahead and real-time opportunity costs, the total annual benefits were calculated to be around US$20 million per year (US$21 million in 2016 and between US$16 and US$19 million in 2024), depending upon the participation of new technology [46, 133]. If benefits persist at such levels for ten years, the present value would be US$137 million, or 10 times the estimated one-time implementation cost of US$12 - 15 million [46, 133].

8.2.7 Lessons from ERCOT

Ultimately, the most important lessons from the ERCOT experience may be that effective stakeholder engagement is essential for significant market changes. Market participants must support the proposed changes, or they are unlikely to be adopted, regardless of the demonstration of clear benefits and good market design. Rather than attempting to re-design the entire ancillary services framework, ERCOT may have received more support for simply introducing several new ancillary services (including a Fast Frequency Response), and leaving the existing services largely untouched. This may have received more support, and been seen more in the light of new opportunities for market participants, rather than (potentially significant) implementation costs. ERCOT's experience provides a cautionary tale for the NEM, when considering adjustments to the existing Frequency Control Ancillary Services framework.

8.3 National Grid (Great Britain)

As outlined in section 3.2, National Grid's modeling has indicated growing challenges around managing RoCoF. Their cost-benefit analysis found that under existing mechanisms, the future increase in response requirement to control frequency is anticipated to be £200m-£250m per annum by 2020 [134, 13]. This estimate is based upon the Gone Green Future Energy Scenario, which gives rise to an increase in RoCoF of 0.3Hz/s [134, 13, 135].

To address this anticipated challenge, National Grid established the "Enhanced Frequency Control Capability (EFCC)/SMART Frequency Control project" [67], introduced in section 4.2. The flagship of the project is the establishment of an "Enhanced Frequency Response" (EFR) service, which requires an active power injection in 1 second (or less), sustained for 15 minutes.

8.3.1 Service specification

National Grid procures the following frequency control services [136]:

- **Primary Response** – Active power response in the period 0-10 seconds from the start of the frequency fall, sustainable for at least a further 20 seconds.
- **Secondary Response** – Active power response fully available within 30 seconds from the time of start of the frequency fall, and sustainable for at least a further 30 minutes.

A new service termed "Enhanced Frequency Response" will be added to these, and is specified as follows.

8.3.1.1 Enhanced Frequency Response (EFR)

National Grid have defined a new service termed "Enhanced Frequency Response" (EFR). Providers of this service must respond to a frequency deviation with 100% active power delivery within 1 second (or less), and be able to sustain output for at least 15 minutes [137].

Notably, EFR is as a *continuous* control service, provided via a droop response to frequency. The aim of the service is to manage system frequency pre-fault (ie. to maintain system frequency closer to 50Hz under *normal* operation). It is *not* designed to arrest frequency decline post-fault [138]. This makes it fundamentally different to the FFR services specified in EirGrid and ERCOT, which are targeted at post fault controls (ie. managing a big drop in frequency, or a big spike in frequency) [136]. The EFR service is more similar to the PJM fast regulation service model, although in the PJM case a central signal (AGC) instructs the battery on what to do (rather than requiring a response based upon locally measured frequency, as is the case for EFR in Great Britain) [136].

The 1 second time delay includes the time that the frequency monitoring device takes to detect a frequency deviation, plus the time for instructing a response and the time for the assets to deliver the MW change in output [137]. The total time delay must be no longer than 1 second in total, with the time delay for detection and instructing response no greater than 500ms [137].

The assets must be able to deliver at 100% EFR capacity for a minimum of 15 minutes [137]. This effectively excludes an emulated response from wind turbines, which only lasts for a duration of ~10 seconds. This may explain why the majority of tenders received by National Grid involved batteries, which can sustain a response for a longer duration. National Grid have indicated that assets with short duration, fast response characteristics “are more suited to post-fault frequency control”, and that the development of such a service (termed “Rapid Frequency Response”, discussed below) will be progressed separately to EFR [136].

Detailed technical specifications are provided for this service in the invitation to tender [137]. Broadly, it includes the requirement for active power delivery as a proportional response to a change in system frequency outside of the dead band (a droop response). The assets must deliver continuous active power within defined service envelopes.

National Grid have defined two types of EFR which differ only in the size of the deadband: ±0.05Hz or ±0.015Hz. They expected that there would be more providers for the wider ±0.05Hz service, but acknowledge that when inertia is high, a service with a ±0.015Hz is more valuable [139]. All eight of the successful tenders are for the narrower ±0.015Hz deadband [140].

Limitations on ramp rates are also defined (except where adherence to these ramp rate limitations would necessitate operation outside of the defined service envelopes) [137]. To meet the ramp rate requirements, assets will need to continuously monitor RoCoF, which given inherent inaccuracies will delay the response to a very fast frequency deviation. However, National Grid felt this was required, to reduce the chances of delivery overshoot, and unpredictable behavior.

Assets used to provide EFR must comply with the fault ride-through conditions specified in the Grid Code. In summary, these conditions require that the assets remain transiently stable and connected to the system for a short circuit fault lasting up to 140ms, and voltage dips lasting longer than 140ms [137].

Assets contracted to provide Enhanced Frequency Response cannot concurrently provide other services, but can provide different services within a day if they are not contracted for Enhanced Frequency Response at these different times [137].

The EFR service is symmetrical, meaning (for example) that an asset providing 25 MW EFR service must deliver 25 MW high frequency response and 25 MW low frequency response, and also that the duration of each must be the same (i.e. the assets must have the ability to deliver, for example, 15 minutes of high and 15 minutes of low frequency response) [136].

8.3.2 Rapid Frequency Response

In 2013, the Frequency Response Workgroup recommended to the Grid Code and Connection and Use of System Code (CUSC) Panels to introduce a "Rapid Frequency Response" requirement for asynchronous generators (including HVDC), requiring a mandatory response fully delivered within 5 seconds [141]. A range of technical challenges were noted as being necessary to address before this service could be implemented.

However, upon conducting further technical analysis, the Workgroup concluded that it could not recommend prioritizing development of emulated inertia, due to the unresolved technical issues [39]. These included challenges relating to the recovery period, and to the inability of wind generators to provide conventional primary frequency response at the same time as emulated inertia [39]. They found that an alternative approach to "speed up" the delivery of primary response may be preferable, and instead shifted focus to firming up delay and ramp rate requirements for the primary response. This could include mandatory requirements for wind turbines to have the capability for primary frequency response [19]. This capability would require wind turbines to fully respond within five seconds, and sustain the response for at least a further 25 seconds [19]. This is interpreted as being provided from wind farm pitch control, rather than emulated inertia, to avoid recovery period issues. National Grid appears to favor this approach, as a more robust method [19]. However, it requires pre-curtailment of the wind farm to deliver this service, which has a comparatively high opportunity cost.

8.3.3 Program of work

The timeline of events in Great Britain is summarized in Table 23.

In 2014, the Systems Operability Framework document quantified RoCoF challenges, giving rise to the award of £6.9m to National Grid (in partnership with Alstom, Belectric, Centrica, Flexitricity, the University of Manchester and the University of Strathclyde) from Ofgem in the "Network Innovation Competition" to deliver the Enhanced Frequency Control Capability project [142].

Table 23 - Great Britain – Timeline of progress [137]

Date	Milestone
September 2014	2014 "Systems Operability Framework" published, raising RoCoF as a challenge [135]
19 December 2014	"Enhanced Frequency Control Capability" project awarded funding through Ofgem (Electricity Network Innovation Competition) [143, 142]
22 September 2015	Invitation for Expressions of Interest in EFR tender [137, 138]
November 2015	2015 "Systems Operability Framework" published, further quantifying RoCoF challenges [17]
11 July 2016	EFR Tender event opened
26 August 2016	Publication of EFR tender results
February 2017	Post EFR tender milestone test (including connection agreement, planning permission, financial close,etc.) [136]
1 March 2018	EFR Latest Service Start Date

8.3.3.1 Expressions of Interest

National Grid commenced the EFR tender process with an invitation to submit "Expressions of Interest", to gauge the market interest [137]. They asked interested parties to provide details of the assets they were proposing to use, their specific technical characteristics and how they performed against a year of second by second frequency data, and any commercial or regulatory issues that they saw as barriers [137].

National Grid received 68 "Expressions of Interest" from a wide variety of parties with a total capacity submitted in excess of 1.3GW, 888 MW of that being from battery projects [137].

8.3.3.2 Pre-qualification

National Grid prequalified 64 offers submitted from 37 separate bidders, making up 1.2 GW of capacity [144]. Most of the submitted offers were batteries. Of the 37 bids received, 34 were for batteries (888 MW) [145]. Nearly all of those were lithium-ion [144]. Two bids were from demand reduction, and the final remaining bid was from thermal generation [145].

8.3.3.3 Tendering

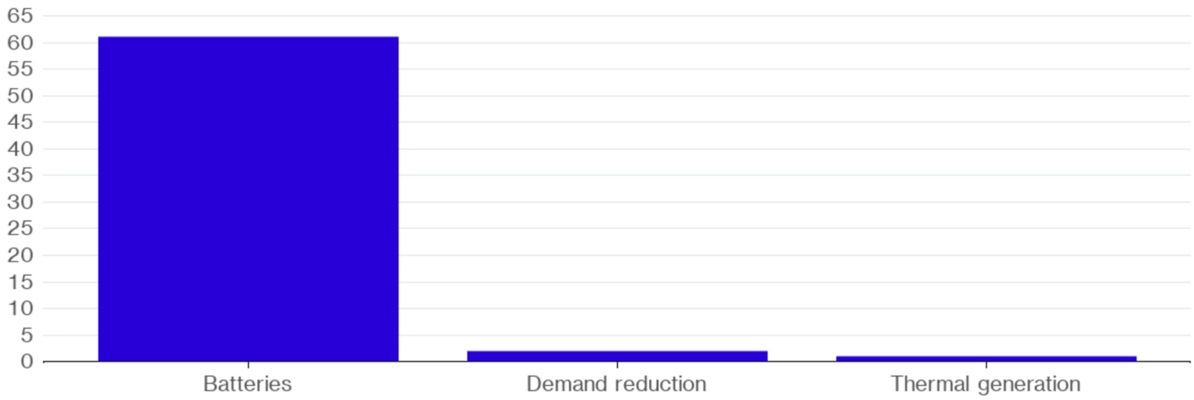
To tender, interested parties supplied details on their chosen site, program of works, connection offer, land rights, financing, and construction contracts [136]. National Grid wanted to ensure that all tenders received were for actual projects that have the best chance of delivery, and not speculative enquiries. Being project specific ensured that a level of engineering, financial and regulatory due diligence had been undertaken [136].

Project sizes were required to be within the range 1MW to 50MW [146, 136]. The 50MW cap was applied to minimize Grid Code compliance issues, and to develop a pool of providers with different technologies and response characteristics, and to minimize risk when procuring a new service [136]. However, National Grid have indicated that the cap is likely to be increased or removed in subsequent tenders [136].

The tender aimed to target 200MW, but if the offers were not economic National Grid would procure less (or may consider more if the offers were economic) [136].

National Grid received tenders from 37 different providers [147]. In total this represented 243 tendered options, 63 for the wide dead band service (service 1) and 180 for the narrow dead band service (service 2) [147]. This totaled 1596 MW of options tendered for the wide service and 4034 MW for the narrow service (although some of these options are mutually exclusive) [147]. The maximum capability per site (regardless of service type and ignoring the 50MW cap per provider) was 1684MW [147]. Of the 64 sites, 61 were classed as Storage, two were demand aggregation and one was thermal generation, as illustrated in Figure 38 [147].

Figure 38 - Number of sites proposed in the EFR tender, of each type [144]



This tender response indicates that there is a growing and active market for storage technologies to provide fast frequency services.

8.3.3.4 Tender Results

Results of the tender were published on 26th August 2016 [148]. National Grid accepted eight bids, providing a combined capacity of 201 MW, from battery storage providers [145]. The companies and projects that won are listed in Table 24.

Table 24 - Successful bidders in EFR tender [144, 145, 146, 140]

Company	Battery size	Location/Site name	Total Cost	Average price (£/MW of EFR/hr)	Estimated start date
EDF Energy Renewables	49 MW	West Burton Power station in Nottinghamshire	£12 million	£7.00 /MWh	Dec 2017
Vattenfall AB	22 MW	Pen y Cymoedd wind farm in South Wales	£5.75 million	£7.45 /MWh	Apr 2017
E.ON SE	10 MW	Blackburn Meadow CHP plant in Sheffield	£3.89 million	£11.09 /MWh	Nov 2017
Low Carbon Storage Investment	10 MW 40MW	Cleator Glassenbury	£15.35 million	£7.94 /MWh £9.38 /MWh	Dec 2017 Mar 2017
Element Power	25 MW	TESS	£10.1 million	£11.49 /MWh	Feb 2018
Renewable Energy Systems (RES)	35 MW	RESEFR7-PT	£14.65 million	£11.93 /MWh	Feb 2018
Belectric Solar	10 MW	Nevendon	£4.2 million	£11.97 /MWh	Oct 2017

The successful bidders won primarily because of the price they submitted, but availability was also taken into account. Most offered to provide the service 24 hours a day, seven days a week [144].

8.3.3.5 Commercial arrangements

Contracts have been awarded for a duration of four years [137]. Although this is not very long when investing in new assets, National Grid felt that longer contracts would pose an unacceptable risk, and that four years provided a good balance between revenue certainty and risk mitigation [136].

Payments to assets will be calculated based upon a Service Performance Measure, calculated per settlement period, second by second. They also apply an "availability factor".

8.3.3.6 Cost benefit assessment

The contracts in the EFR tender will cost National Grid £66 million [146]. National Grid spends in the vicinity of £160 million - £170 million per year on frequency control, and estimates that the introduction of the Enhanced Frequency Response service will save £200 million over four years [144].

8.3.3.7 Next steps

The successful bidders must pass post-tender milestone tests (such as connection agreement, planning permission, financial close, etc.) around February, and achieve full commissioning by 1st March 2018 [144].

National Grid foresees a requirement for this type of service increasing over the next few years, and therefore intends to run regular tender events on an enduring basis [146]. They have indicated an intention to add 30 percent more of such units by 2020 [144], and perhaps eventually as much as two or three times more than the 200 MW procured in this tender [136], based upon the modeling published in the SOF [17].

8.4 MISO (Mid-continent USA)

The Mid-continent Independent System Operator (MISO) has introduced an explicit market product to address ramping concerns [149]. Although MISO features a five minute dispatch, they believe that unanticipated deviations from the expected net load or high rates of change in net load *beyond* the 5-minute dispatch horizon can hinder their ability to get needed generation to ramp up quickly enough to help meet high demand [150]. This in turn, could lead to a short-term scarcity. They anticipate that this challenge will grow in future, with the growth in variable generation [150]. MISO notes that ramp shortages are the most common cause of short-term scarcities and price spikes; when the system has capacity online, but it is not rampable, prices rise to scarcity levels, then quickly drop back [151]. These scarcities result in issues of price volatility, and day-ahead/real-time price divergence [151]. MISO proposes that their ramping product will provide transparent price signals to provide effective economic incentives for resource flexibility [151].

The ramping product is designed to respond to short-term variations in load by holding back a portion of "rampable capacity" from the five minute dispatch [149]. MISO sets ramp requirements for the day-ahead and real-time markets based on load forecasts and historical analysis [149]. The ramp requirements are designed to manage both expected net load changes (variations) and unexpected net load changes (uncertainties) over a defined response time of 10 minutes [151].

Resources able to respond to five-minute energy dispatch instructions (generation, and some types of demand response) will be able to offer ramp capability [149]. Energy storage is not eligible, and dispatchable intermittent resources will be able to provide down ramp based on their ability to reduce output [149]. Resources that are dispatched out of merit order through the clearing of up or down ramp capability will be compensated for lost opportunity costs at a maximum of $5/MWh [149].

The concept was first recommended in 2011 (in a State of the Market Report) [151], detailed further in a white paper in 2013 with a cost benefit analysis [152], and launched in April 2016 [149], as listed in Table 25.

Table 25 - Timeline of events in MISO

Date	Milestone
2011-2013	Ramp capability product design
2013-2014	Proposal development with stakeholders
December 2014	Filing of ramp capability product design with FERC
31 October 2014	FERC accepts MISO introducing new ramping product [153]
1 April 2016	Launch of MISO ramp capability software [149, 151]

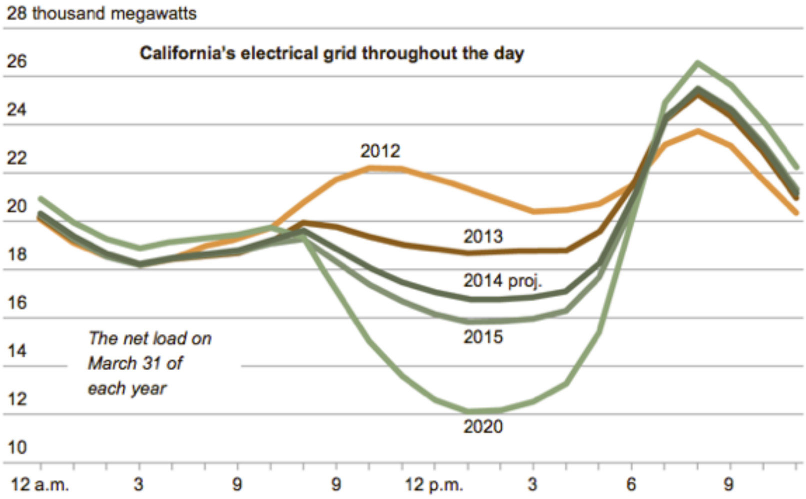
MISO believes the ramping product could save US$3.8 million to US$5.4 million in dispatch and commitment costs [149], after consideration of the impact of additional costs of US$2-4 million in operational costs to provide the ramp capability products [152]. They believe that the ramping product is a less expensive solution than increasing regulation requirements [152], which are typically in the range of US$10-20/MWh. The availability of regulation in MISO is limited. They felt that unbundling of these products was a more optimal solution, from a cost perspective [154].

MISO will conduct a study on the ramp product to gauge effectiveness over its first few years of operation [149]. The results of this study should be of interest to AEMO, in considering whether a similar product could be beneficial in the NEM.

8.5 CAISO (California, USA)

California has become known internationally for introducing the “duck curve”, as illustrated in Figure 39. This figure shows the impact of solar generation on net supply/demand. Of particular concern for the California Independent System Operator (CAISO) was the increasingly rapid ramping required from the balance of system in the evening, as solar resources ramp down generation, simultaneously with growth in the evening peak demand. This led to concerns about the adequacy of ramping resources.

Figure 39 - California "Duck Curve", showing net supply/demand on the California grid in 2012-13, and forecast to 2020 [155]



In response, in 2011 CAISO implemented a flexible ramping constraint, to help ensure that sufficient resources were available to meet forecast uncertainty for upward ramping needs. Resources that resolve the constraint are compensated at the shadow price, which is the marginal unit's resource specific opportunity cost [156]. At this time, they committed to design a product that would more effectively dispatch resources to meet ramping needs. This product has been termed the "Flexible Ramping Product" [157]. The Flexible Ramping Product will replace the existing flexible market constraint and provide the CAISO with a means to procure sufficient ramping capacity through economic bids [156].

The Flexible Ramping Product is designed to deal with uncertainties that are realized before the binding real-time dispatch, using a market-based design to procure ramping capacity in the CAISO's day-ahead market, fifteen-minute market and real-time dispatch [156]. The Flexible Ramping Product procures and compensates resources for providing ramping capability to meet the *forecasted movement* of net load (gross load forecast, less the wind and solar output), and *uncertainty* in the forecasted net load [157].

For *forecasted movement*, resources (load or supply) that increase the need for ramping capability will be charged for the flexible ramping product, while resources that decrease the need for ramping capability between intervals will receive a payment. It is anticipated that this will incentivize retailers to have a portfolio of resources that can follow their load profile [157].

For *uncertainty,* the flexible ramping product will procure an additional amount of ramping capability to cover uncertainty in the forecasted net load, if the expected benefits of this additional ramping capability exceed its costs. CAISO will determine this trade-off by calculating the probability of a power balance violation due to a deficiency in imbalance energy, and the associated costs to the market, and comparing this to the costs to procure ramping capability [157]. The costs of the ramping capability for uncertainty will be calculated using a procurement curve [158], and allocated based on each resource's contribution to uncertainty in each month.

CAISO has completed an extensive stakeholder engagement process over four years to design the product. To alleviate remaining stakeholder concerns, CAISO will conduct a "market simulation" prior to implementing the new product, to evaluate whether the tool will work as expected. The timeline of events is outlined in Table 26.

Table 26 - Timeline of events in CAISO

Date	Milestone
December 2011	Implemented a flexible ramping constraint interim compensation methodology [156]
2 June 2014	Straw Proposal published [159]
24 June 2016	CAISO filed proposal for "Flexible Ramping Product" [157]
August 2016	Market simulation of the Flexible Ramping Product commenced

Participants will not submit separate bids for the flexible ramping product (as is done for ancillary services capacity). Instead, CAISO will use energy bids for optimizing procurement [158].

Like MISO, CAISO believes that while the existing regulation service product could be called upon to address forecast uncertainties, procuring more regulation service is likely to be a more costly option than introducing an unbundled ramping service [156].

Further details on the Flexible Ramping Product are outlined comprehensively and accessibly in Section III of reference [157].

It is unclear whether the NEM will face similar issues related to ramping capability. Unlike the NEM, CAISO and MISO both have complex day ahead market frameworks, which may create different price signals, and limit the flexibility and incentives for resources to ramp rapidly in the real-time market. However, the experiences of these jurisdictions does suggest that AEMO should conduct analysis to investigate whether ramping is similarly of concern in the NEM, and whether introducing a ramping product may be necessary to ensure adequate ramping capability, or whether it may have the potential to reduce ancillary services costs.

8.6 Conclusions

A number of jurisdictions have invested considerable time and effort in developing new ancillary services frameworks, in response to growing penetrations of non-synchronous, variable generation. A common theme across these new frameworks is the introduction of some kind of FFR or fast frequency control, as summarized in Table 3.

Table 27 - Fast Frequency Ancillary Services introduced or considered internationally

	Service type	Response time	Sustain duration	Notes
Ireland (EirGrid/SONI)	FFR – contingency service, triggered by local frequency	2 seconds	8 seconds	To be implemented October 2016
Texas (ERCOT)	FFR - contingency service, triggered by local frequency	0.5 seconds	10 minutes	All proposed changes rejected (May 2016)
Great Britain (National Grid)	EFR – Continuous frequency regulation via droop response to local frequency	1 second	15 minutes	Procured via tender process (Aug 2016), to be installed by 1 Mar 2018,

EirGrid/SONI and ERCOT's proposed frameworks also include introducing a Synchronous Inertial Response (SIR) service, providing a precedent for potentially introducing something similar in the NEM.

As of the time of writing this report, none of these proposed changes have yet been implemented; this means that key lessons for the NEM are limited to considering their proposals, and the work that went into developing and justifying them. This review did not encounter *any* jurisdiction that has an operating FFR-type service, at present.[9] This highlights the need for caution and careful management of stakeholder expectations in developing a new FFR-type service in the NEM. Furthermore, EirGrid is the only example of another jurisdiction that will soon introduce an FFR-type service, and they have elected to specify a 2-second response time. This is considerably slower than the capabilities of some technologies (some of which can respond within 20ms), and is likely due to EirGrid's extensive analysis and resulting caution around the challenges associated with robust detection and measurement of high RoCoF events.

[9] PJM's fast regulation service is provided by fast-reacting batteries, but is controlled via AGC, and therefore is technically distinct from a fast active power injection in response to a contingency event.

Some jurisdictions (EirGrid/SONI, MISO and CAISO) are also introducing new ancillary service products for managing ramping and variability over timeframes longer than a dispatch interval. These are discussed further in the insights below.

8.6.1 Insights for the NEM

8.6.1.1 Collaboration with EirGrid/SONI on new ancillary services

EirGrid/SONI are the most advanced in the development and implementation of a comprehensive frequency control ancillary services framework, to operate in a system with high RoCoF exposure and large quantities of variable generation. In particular, they are about to introduce a 2-second FFR-type service, which could provide a model for a similar service in the NEM. To our knowledge, this will be the first practical demonstration of a service of this kind, in any jurisdiction.

EirGrid/SONI's "Qualification Trial Process" may also be of interest. This process aims to demonstrate the capabilities of emerging technologies for delivering the relevant frequency control services (including the FFR-type service). Results are expected in mid-2017.

AEMO could explore the potential for collaborating with EirGrid/SONI to share information and insights through their experience implementing these new services. This could also offer value to EirGrid/SONI, given the sophisticated and efficient frequency control ancillary services framework already in operation in the NEM [14].

8.6.1.2 Fast post-fault active power recovery

EirGrid/SONI have established an explicit ancillary service for fast post-fault active power recovery (requiring a maximum of 250 ms to return to 90% active power, post-fault). Active power recovery of non-synchronous generators post-fault can be a significant issue, potentially exacerbating frequency disturbances, and challenging the delivery of FFR-type services. EirGrid/SONI's experiences with this service may provide a model for a similar approach in the NEM.

8.6.1.3 Ramping services

EirGrid/SONI, MISO and CAISO have all introduced products that aim to procure ramping services, over timeframes longer than a dispatch interval. These are seen as important in MISO and CAISO to ensure adequate system flexibility to meet large, long timescale ramps caused by growing renewable penetrations, and to improve price signals for flexibility.

AEMO could conduct an analysis to determine the NEM's likely future ramping requirements, to determine whether this could be an issue, and explore the potential for improving price signals by introducing an explicit ramping product. Careful consideration should be given to the differences between the NEM and these other jurisdictions with regards to day-ahead markets and other frameworks that may limit or distort effective price signals for flexibility.

8.6.1.4 Adjusting existing services

ERCOT spent many years developing a comprehensive new ancillary services framework, only to have it ultimately rejected in May 2016. The most important lessons from the ERCOT experience may be that effective stakeholder engagement is essential for significant market changes. Market participants must support the proposed changes, or they are unlikely to be adopted, regardless of the careful demonstration of clear benefits and good market design.

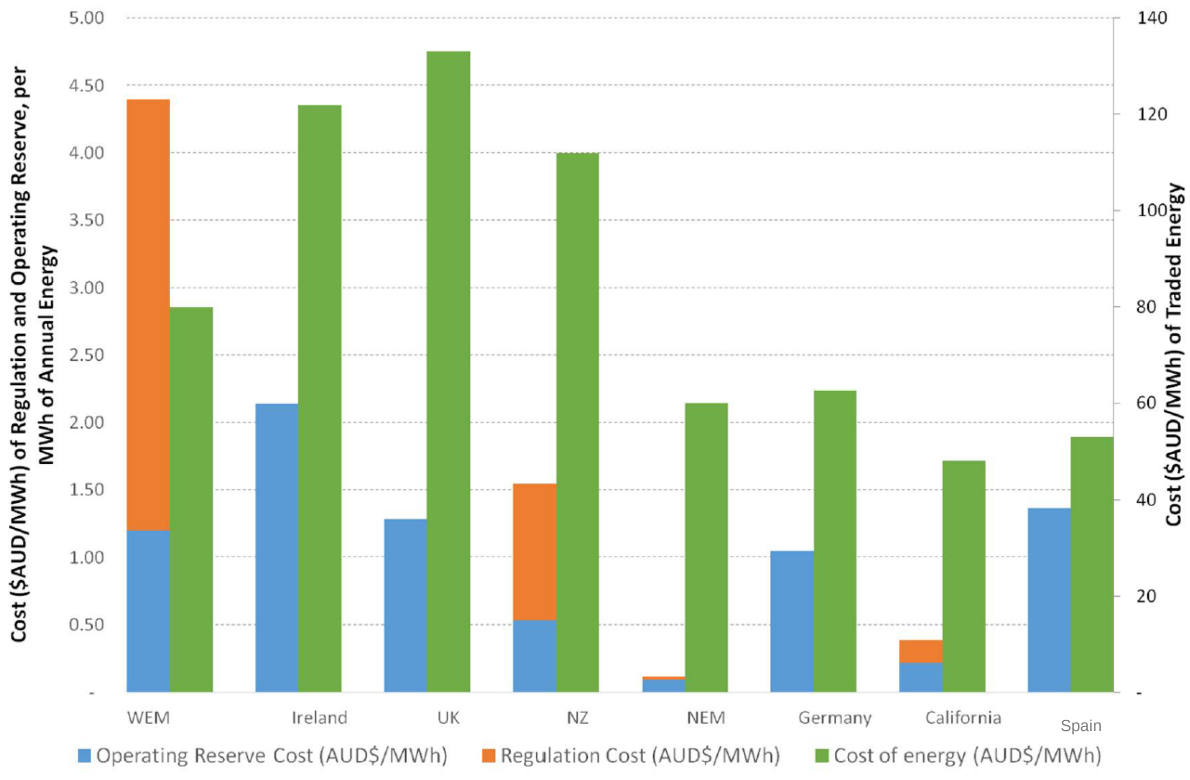
9 OTHER ASPECTS OF FREQUENCY CONTROL

This review uncovered a range of other insights and important factors for consideration in the adaptation of frequency control ancillary services; these are provided in this section.

9.1 Cost comparison for frequency control services

Figure 40 compares the costs of frequency control services in the NEM to other jurisdictions [131]. Regulation costs are shown in orange, while blue shows the costs of reserves for managing contingency events [131]. The UK, Spain, Germany and Ireland use reserves procured for contingency events to provide regulation and therefore do not separate the two different services [131]. The WEM is the Wholesale Electricity Market in Western Australia.

Figure 40 - Comparison of costs of frequency control in 2012-13 [131]



It is evident that frequency control is significantly less expensive in the NEM than in other jurisdictions. This could be due to a range of contributing factors, including [131]:

- Dynamic procurement of regulation reserves, as discussed above.
- A five minute dispatch interval (also used in California and New Zealand). Faster energy markets (i.e., shorter intervals between full system dispatch) reduce the regulation requirement by allowing regulation units to be returned to their set points more frequently [160, 161].

- Procurement of all frequency control services through a market, operating on the same dispatch interval as the energy market. This is likely to be more economically efficient than having a regulated tariff for all services, as in Ireland, or tendered contracts for longer periods of time, as in the UK and Germany [131].
- A large fleet of responsive, AGC capable generators which can provide regulation and operating reserve at relatively low effort and hence cost [131].
- Compared with some of the examples shown (such as Ireland and the WEM), the NEM has a relatively larger market, giving access to more potential providers [162], and smaller contingencies relative to market size. The smaller size of those markets may partially explain their relatively higher costs.

This suggests that the NEM can provide valuable lessons on efficient frequency control to other jurisdictions, rather than the opposite [14].

9.2 Regulation Services

Regulation services manage variability and uncertainty within dispatch intervals, on an ongoing basis. They are typically operated via Automatic Generation Control (AGC) by the system operator.

9.2.1 Setting regulation requirements

In most jurisdictions, regulation requirements are set via operational experience and refined over time, rather than being determined via a formal methodology [131]. Typically, the regulation requirement is calculated in advance, and is typically set at a fixed value in all hours, or over pre-defined time periods (eg. Peak, shoulder, off-peak, etc.) [163]. For example, in the PJM market, the regulation requirement (as of December 2013) is set at 700 MW in peak periods (5am to midnight), and 525 MW in off-peak periods (all other times). Although this provides a simple and transparent approach, a flat reserve level is likely to be insufficient for difficult periods and economically inefficient for low volatility/low ramp periods. Most markets allow the system operator to activate additional reserves if they are deemed necessary in real time [131].

Other markets set the regulation requirement through an empirical model, providing additional reserves at times of anticipated greater need. For example, in PJM, the regulation requirement was previously set at 1.0% or 0.7% of the peak/off-peak system load [164]; (the implicit assumption being that the size of fluctuations will be proportional to the system load).

The NEM's approach is more sophisticated, varying the regulation amount in response to the time error (with the implicit assumption that if frequency control cannot be stabilized over a protracted period, additional regulation should be enabled) [131]. Minimum quantities have been determined by AEMO through operational experience [131]. This suggests that there is more likely to be potential for the NEM to provide valuable lessons to other jurisdictions in the area of frequency regulation, rather than the opposite [14].

9.2.2 Dynamic regulation requirements

In the future, a more "sculpted" approach to procuring reserves, allowing the quantities procured to vary in real time according to system need, could reduce total costs and provide clearer price signals to participants [165]. For example, this could include procuring additional regulation at times of high solar and wind variability (and less at times when variability is low) [165]. For wind, the contribution to variability has been observed to be highest when wind farms are operating at the midpoint of their power curve [163, 166].

Currently, this type of sculpting is not common. California schedules regulation reserve separately for each hour of the day in the day-ahead market (based on the forecast changes in generation, inter-ties, demand and the start-up or shut-down of units) [167]. In the real time dispatch, more or less regulation can be procured as required due to outages or deviations in demand from the forecast. This system encountered challenges when introduced in 2011, with 24 instances where the regulation scheduled could not be delivered in the real time market [168]. These issues have been mostly resolved, with only one scarcity event in each of 2012 and 2013. They highlight the complexities of implementing real time regulation requirements in practice.

There may be opportunities to improve the efficiency of regulation in the NEM. For example, a tool could be developed for the control room to project likely variability (based upon wind and solar generation levels, for example), to provide additional information to system operators on the amount of regulation likely to be required. This could be used to pre-emptively enable more regulation during periods of significant variability, without waiting for the time error to deviate.

9.3 Wind farm capabilities for frequency control

The National Renewable Energy Laboratory (NREL) and the Electric Power Research Institute (EPRI) have collaborated on a project to demonstrate the capability of wind farms to provide active power control of various kinds, including emulated inertia, primary frequency control, and regulation [98]. They conducted modeling and field testing of wind turbines to demonstrate these capabilities.

NREL indicate that wind plants can implement a primary frequency response through droop characteristics, which can be non-symmetric, as illustrated in Figure 41. The various parameters (deadbands, droops, reserve margins) can be tuned to different values for optimum system performance [98].

Figure 41 - Primary Frequency Control implemented with a frequency droop on a wind power plant [98]

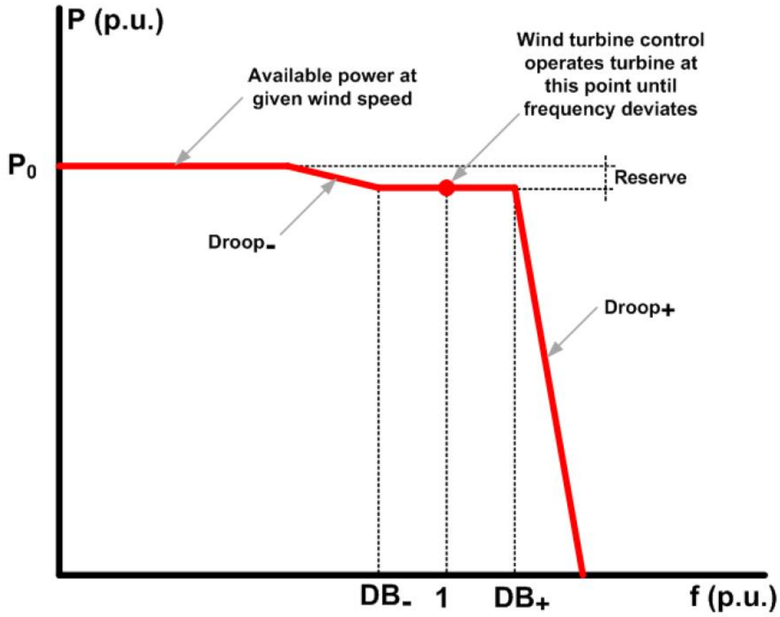
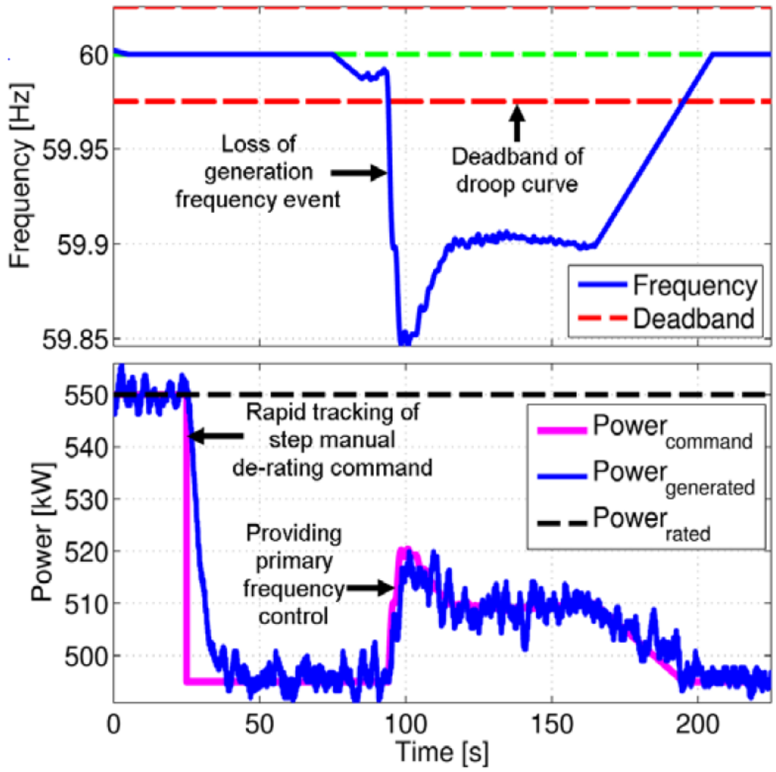


Figure 42 shows a field test of a single wind turbine, responding to a de-rate command (stepping from 100% to 90% active power). This is then followed by a simulated under-frequency event (producing a primary frequency response). The turbine successfully provided both responses, as required. The high frequency fluctuations are likely to be smoothed out significantly when an entire wind plant is considered, rather than just a single turbine [98].

This demonstrates that wind farms are likely to be able to provide both raise and lower contingency services, on the 6s, 60s and 5min timeframes required in the NEM, using pitch control at the plant supervisory control level (if they are appropriately designed to do so). Of course, providing a raise service will require the plant to be pre-curtailed; these results indicate that this is likely to be technically feasible, but will have a non-trivial opportunity cost in the spilled energy.

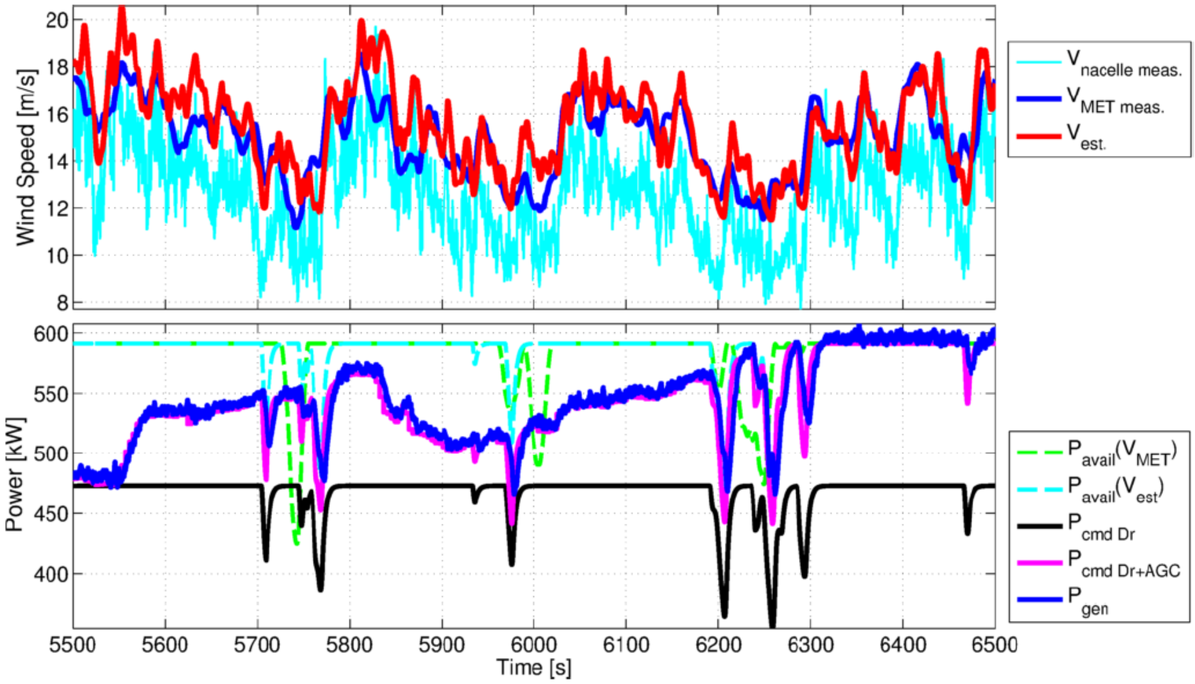
Figure 42 - Field test data showing a wind turbine tracking a step change in the de-rating command, followed by Primary Frequency Control response to an under frequency event [98]



Similarly, Figure 43 demonstrates a wind turbine following an AGC command (derived from actual data from the Western Interconnection in the USA) [98]. In this example, the turbine is given a de-rating command when the available wind power drops below rated power [98]. The controller estimates the power available in the wind (P_{avail}), de-rates with respect to the estimation so that there is power overhead to follow the AGC command ($P_{cmd\ Dr}$), and then tracks this level plus the AGC command ($P_{cmd\ Dr + AGC}$) [98]. The signal P_{gen} is the actual output power, which effectively tracks the desired output power, even given the varying wind conditions [98]. These preliminary results show a wind turbine's capability to rapidly and accurately track a power command signal. The regulation performance significantly degrades at higher power set-points as the wind speed decreases and the wind turbulence intensity increases, so probabilistic wind forecast models may be required to assess the economic viability of wind plants participating in a regulation market [98].

This indicates that wind farms have the capability to follow an AGC signal, and provide a regulation service, if designed with the appropriate control systems.

Figure 43 - Field test of a wind turbine following an AGC command [98]



9.4 Mandatory Frequency Control Capabilities

9.4.1 National Grid (Great Britain)

It is an obligation for all generators to have the capability to provide mandatory frequency response, according to the Grid Code in Great Britain (as a condition of connection) [169]. This refers to the capability to provide frequency response, but does not mandate the physical delivery of the service [169]. A generator may never be called upon for the physical delivery of the service, if the system operator can find the necessary response at a more cost effective price.

All generators must have the capability to provide [169]:

- Primary response (within 10 seconds, sustainable for 30 seconds)
- Secondary response (within 30 seconds, sustainable for 30 minutes)
- High frequency response (within 10 seconds, sustainable thereafter). This refers to over-frequency events.

The required level of response is 10% of registered capacity, for all three categories of service [169]. All generating units must have a 3-5% governor droop characteristic, and be capable of providing continuous active power response through their automatic governing systems [15].

9.5 Over-frequency response

Some jurisdictions require mandatory capabilities for frequency control, as discussed below. AEMO could consider this as an option in the NEM, for certain capabilities, where these can be included at minimal additional cost upon installation.

This is particularly relevant for over-frequency controls from non-synchronous generation. As noted earlier, the emulated inertial control from wind generation is asymmetric; it only responds to low frequencies. However, wind turbines (and other inverter-connected technologies) are also capable of useful over-frequency responses. Wind and PV can generally ramp down their active power very rapidly, and this does not require pre-curtailment of the plant (which has a comparatively high opportunity cost). This capability is mandated in a range of jurisdictions, as outlined below.

9.5.1 ENTSO-E (Europe)

As noted earlier, ENTSO-E, the European Network of Transmission System Operators, represents 42 electricity transmission system operators (TSOs) from 35 countries across Europe, including Germany, Denmark, Ireland, and Great Britain. ENTSO-E drafted a "Network Code Requirements for Grid Connection" applicable to all generators, aiming to harmonize solutions and products. This was recently accepted by the European Parliament, and became a binding regulation in the EU on 17 May 2016 [42].

The ENTSO-E Network Code defines an operational mode termed "limited frequency sensitive mode – Overfrequency" (LFSM-O) [43]. When operating in this mode, the generator must provide an active power response with an over-frequency droop response. The frequency threshold must be between 50.2Hz and 50.5Hz, with a droop setting between 2% and 12% with the exact settings specified by the relevant TSO [43].

9.5.2 National Grid (Great Britain)

The Grid Code in Great Britain requires that generators [170]:

> *"reduce Active Power output in response to an increase in System Frequency above 50.5 Hz at a minimum rate of 2 per cent of output per 0.1 Hz deviation of System Frequency above that level, such reduction to be achieved within five minutes of the rise to or above 50.5 Hz."*

Generators must also be able to operate in "Frequency Sensitive Mode", and in this case, when instructed must provide a "High Frequency Response", at frequencies up to 50.5Hz, in accordance with their respective Ancillary Services Agreements [170].

9.5.3 EirGrid (Ireland)

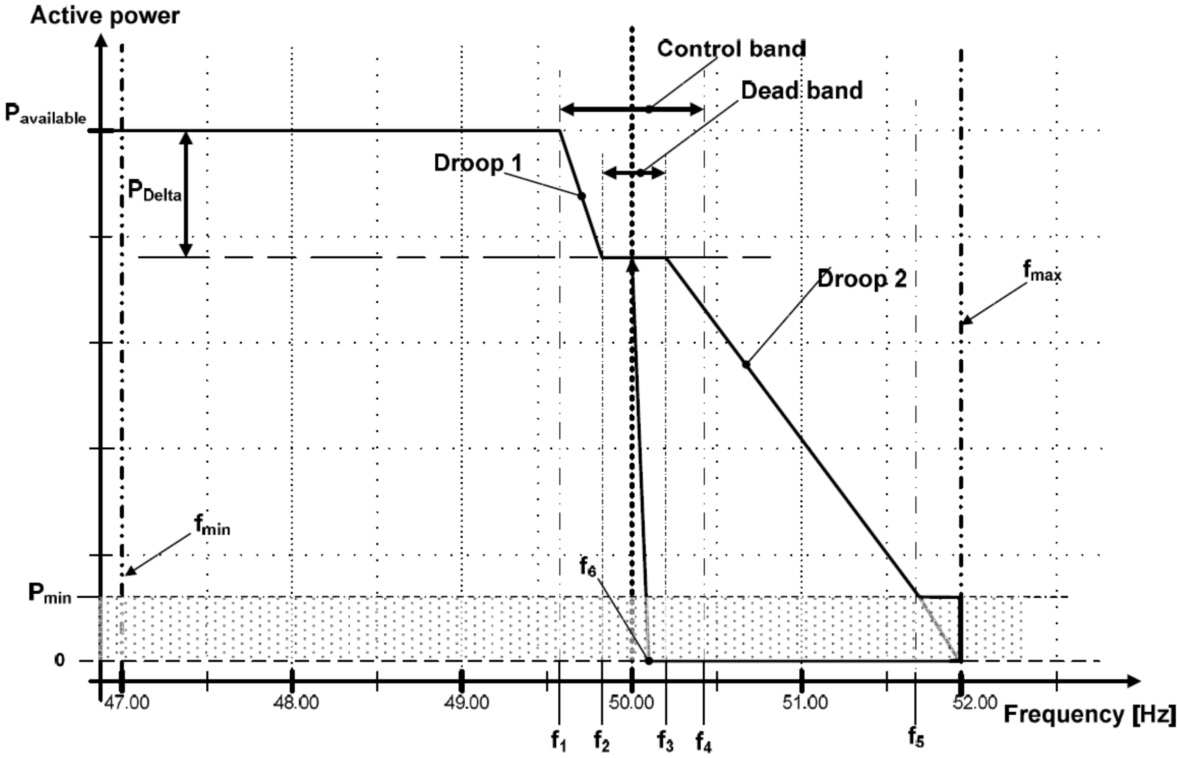
EirGrid's Grid Code requires that all generators respond to frequencies above 50.2 Hz by automatic or manual reduction in active power output, without delay, and without receipt of instruction from the system operator [171].

9.5.4 Eskom (South Africa)

South Africa's Grid Code requires that "Renewable Power Plants" (RPPs) defines the frequency control droop settings as illustrated [55]. This includes the requirement to provide a mandatory high frequency response, with the over-frequency response commencing at 50.5 Hz (f_4), and being completely curtailed above 52 Hz.

The requirement for P_{Delta}, a frequency control set point below the total available active power, implies a requirement to spill energy on an ongoing basis in order to provide the ability for an active power increase when required. However, the default is that there is no requirement for P_{Delta}, the dead band, and the control band functions, unless by specific agreement with the System Operator. However, the grid code requires the *capability* to set these control functions as required (within defined ranges). It also requires that the frequency control set point (P_{Delta}) can be changed rapidly, with the change commenced within two seconds and completed no later than 10 seconds after receipt of an order.

Figure 44 - Frequency response requirement for Renewable Power Plants defined in South African grid code [55]



This approach ensures that the System Operator can elicit a sophisticated frequency response (to manage both over frequency and under frequency events) from all renewable generators in the system as required, but does not involve substantial ongoing opportunity costs in spilled generation (since this capability is not required to be enabled in unless directed).

9.5.5 ERCOT (Texas)

Since 2010, ERCOT has required wind projects to have primary frequency response capabilities [172], if they are operating at a point where they can do so. They are not paid to provide this service [87]. Wind plants must have adjustable dead bands comparable to conventional resources, and a similar droop to the other resources of 5% [95, 87, 172]. Wind farms are not required to provide an under-frequency primary frequency response unless they were previously curtailed, and therefore have "headroom" to provide more energy during under-frequency events [98].

9.5.6 Ontario

Ontario's market rules require that all generators regulate speed with an average droop based on maximum active power, adjustable between 3% and 7%, and set at 4% unless otherwise specified by the system operator. The regulation dead band must be no wider than ±0.06% [173].

Specifically, all generation types (e.g. conventional, wind, solar) must reduce active power for over-frequency excursions outside of the ±0.06% (i.e. 36 mHz) dead band [102].

Wind farms are expected to respond to system frequency decline by temporarily boosting active power output for some time (i.e. 10 s) by recovering energy from the rotating blades (an "inertia emulation control" function within the wind farm control system). It is not required for wind facilities to provide a sustained response to system frequency decline [103, 104]. This means that wind farms do not need to continually "spill" energy to provide this capability [102]. The details of this service requirement are outlined in section 7.3.

Wind farms may connect without an inertial emulation control capability (if it is not commercially available), but the system operator reserves the right to ask for this applicant to install this function in future, when it is available for the proposed type of turbine [105, 103].

9.6 Ramp Rate Limitations

9.6.1 Denmark

In Denmark, for large wind farms, a maximum upward ramp rate can be imposed to reduce stress on the system if they are deemed during the connection approval process to be connecting to a vulnerable part of the grid. The ramp rate limit then applies at all times [131, 174].

9.6.2 Hawaii

Hawaii has implemented comparatively strict requirements for the frequency control capabilities for wind generation. For example, the request for proposals for 200 MW or more of renewable energy for Oahu in 2011 included several control requirements for wind projects, including curtailment capability, frequency regulation, capability to provide reactive power at 90% lagging and 95% leading, and the ability to ride through over-voltage and under and over-frequency events [87]. They also require ramp rate control of 2 MW/minute for projects of 5 MW to 25 MW, 3 MW/minute for 25 to 50 MW, 3 to 5 MW/minute for 50 to 100 MW, and 5 to 10 MW/minute for 100 to 200 MW [87]. Generators are limited in size to 200 MW unless a larger generator can limit the loss of generation to 200

MW in a single contingency event [87]. However, to date, it appears that Hawaii has not required an emulated inertial response from wind generation.

9.7 Conclusions

Reviews comparing frequency control costs have found that frequency control in the NEM is significantly less expensive than in many other jurisdictions (such as Ireland, Great Britain, New Zealand, Germany and Spain). This suggests that the NEM can probably offer valuable insights on frequency control frameworks to other jurisdictions rather than the reverse. The low cost of FCAS in the NEM is likely to be due to a range of factors, including procurement through a competitive, five-minute market, in real-time, from a wide range of potential providers, co-optimized with energy, across the entire NEM market (in most periods).

However, this review found a number of other insights that the NEM can draw from international jurisdictions on other aspects of frequency control, as outlined in the insights below.

9.7.1 Insights for the NEM

9.7.1.1 Sculpted minimum regulation requirements

International studies have found that the variability of wind and PV generation depends upon their level of operation. For example, PV doesn't contribute additional variability overnight (since they are not operating). For wind generation, variability has been found to be lower during periods when they are operating at their extremities (high or low generation), and highest when wind turbines are operating around their mid-point (when the turbine power curve is steepest). This creates opportunities to anticipate the level of power system variability from wind and PV, and to provide the system operator with additional tools to pre-emptively and efficiently manage that variability (by scheduling more regulation services when required, for example).

9.7.1.2 Frequency control capabilities

Other jurisdictions (such as Great Britain) have mandatory requirements for all generators (including wind farms) to have the *capability* to provide a wide range of frequency control services (even if these are never called upon in practice).

Generators installed today are anticipated to remain in operation for 10-30 years, and it is clear that new providers of frequency control services will be required in future (given anticipated retirement of plant that currently provide these services). Retrofit of these capabilities (including the necessary calibration, testing, and verification) could be much more costly and complex than including the capability when the plant is first installed (and the OEM is already involved in the testing and verification process). For these reasons, it may be prudent to encourage the inclusion of frequency control capabilities in new entrants.

International analysis suggests that wind farms should be capable of providing all of the frequency control ancillary services specified in the NEM, if designed to include this capability.

9.7.1.3 Over-frequency response

This review has mostly focused on management of under-frequency disturbances (caused by an unexpected loss in generation). However, over-frequency events are also a concern, and their management will similarly become more challenging as inertia levels go down, and RoCoF levels go up. This suggests that new approaches to manage over-frequency events may be required.

International studies indicate that wind farms and PV are capable of providing an effective over-frequency response (reducing active power rapidly), if designed with this control capability (often through a droop response). Unlike a primary frequency response for under-frequency, this does not require pre-curtailment of the farm, and therefore can be achieved with a minimal opportunity cost.

A number of other jurisdictions require a mandatory over-frequency response from non-synchronous generation; this review found requirements of this nature in the grid codes for Ireland, South Africa and ERCOT.

9.7.1.4 Ramp Rate Limitations

Some other jurisdictions (Denmark and Hawaii) have introduced mandatory ramp rate limitations for variable generation. In Denmark this is negotiated during the connection process, while in Hawaii strict ramp rate controls are required.

A similar approach could potentially be applied in the NEM, but should be carefully examined via a cost-benefit analysis prior to implementation. In particular, since frequency control depends upon the system-wide supply-demand balance, there are considerable benefits from aggregating various sources of variability, and managing imbalances at the largest scale possible. This suggests that ramp rate limitations on individual plant should only be applied as a last resort, and only where there is a need to manage local considerations (such distribution network issues, for example).

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