Innovation in the Power Systems Industry

Engineers and specialists worldwide exchange information and state-of-the-art world practices to enhance knowledge related to power systems in CIGRE’s latest publication.

Best papers from CIGRE Chengdu 2019 Symposium
and from SC B5 Protection and Automation
Colloquium in Tromsø

Reference papers from SC C2, Power system operation and control, and SC C4, Power system technical performance
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Dear readers,

The new year has started in the best possible way for CIGRE Science & Engineering, as we have received confirmation that our journal has been accepted for inclusion in Scopus, the prestigious database for scientific publications. This means that articles published in our Journal will be indexed by Scopus, which is very important, especially for our authors from academic institutions.

The main points of the positive evaluation of our Journal by the Scopus team have been:

- The journal systematically includes articles that are scientifically sound and relevant to an international academic or professional audience in the field.
- In general, the content of the articles is consistent with the scope and objectives of the journal.
- Articles are generally well-written and understandable.
- The type of peer review is clearly indicated and is supported by appropriate guidelines for reviewers.

In addition, and as succinctly mentioned in the editorial by CIGRE President Dr. Rob Stephen in the February 2020 issue of ELECTRA:

- Peer review is carried out by the best specialists in their field worldwide.
- Only papers of the highest quality are accepted.
- There is no charge for publication.
- CSE is distributed worldwide and can be downloaded free of charge, giving authors maximum exposure.
- Authors are informed within one month of their request for publication and immediately after publication of their article.

Needless to say, I am extremely proud and pleased with this achievement and I would like to thank all the authors, the reviewers, the members of the editorial board, the members of the CIGRE technical board and all CIGRE staff members for their significant contribution and continued support over the years to the creation of a first-class publication. And, of course, we at CSE are determined to continue to do so!

In this sense, this issue contains a plethora of interesting papers, including a key SC C2 paper on “System Operational Challenges in the Energy Transition” and two key SC C4 papers on “Energy Quality Trends in the Transition to a Carbon-Free Electricity System” and on “The Need for Enhanced Power System Modelling Techniques and Simulation Tools”, which are extended versions of the related reference documents published in ELECTRA No. 308, February 2020.

This gives me the opportunity to point out that these documents are extremely valuable, as they do not represent the opinion of the authors but are based on the consensus of the world’s best experts on a specific topic. That is why CIGRE documents and technical brochures are very often used as a basis for IEC and other standards.

A major event in 2019 was the CIGRE Chengdu 2019 Symposium, hosted by the Chinese National Committee of CIGRE in Chengdu, China, from 20 to 26 September 2019. With the participation of six Study (B3, B5, C1, C3, C6 and D2), the symposium, whose theme was “Towards active, sustainable digital networks that are resilient and integrated from UHV to distribution”, covered important issues currently facing the power system industry. In addition, it highlighted the fact that CIGRE is indeed an end-to-end (E2E) association covering all voltage levels from Low to Ultra-High Voltage. During the six days of the symposium, 336 participants from 30 countries (219 from China and 117 from other countries) met and 72 papers from 19 countries were presented in 15 oral sessions. The best papers, one per Study Committee, were selected and are presented in this issue of CSE.

You will also find in this issue the three best papers from the Colloquium SC B5 - Protection and Automation - held in Tromsø, Norway, 24-28 June 2019, with more than 135 delegates and 79 contributions received.

Finally, this issue includes four articles covering mainly issues related to the operation of inverter-based power generation systems, a very topical subject.

Wishing you a very enjoyable reading,

Prof. Dr. Konstantin O. Papailiou  
Chief Editor  
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System Operational Challenges from the Energy Transition

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Abstract
System operators face a proliferation of power electronics interfaced devices such as HVDC transmission lines, wind and solar generation in their grids. Depending on the jurisdiction, the instantaneous share of electrical energy produced from renewable energy sources occasionally reaches 150%. However, to operate a power system with sustained high levels of renewable energy, several operational challenges need to be addressed. The goal of this survey paper, which is one of the products of CIGRE joint working group C2/B4.38, is to identify such challenges. To this extend, extensive literature review and survey among and discussions with system operators throughout the world were performed.

This paper identified several operational challenges that were validated by system operators. These challenges are grouped in the following three categories: (i) new behavior of the power system, (ii) new operation of the power system and (iii) lack of voltage and frequency support. For each of the identified challenge, a description, practical examples and relevant references are provided.

The next step in the activities of the joint working group is to identify how power electronics interfaced devices can support in mitigating some of the identified challenges. This will be presented in a subsequent article.

1. Introduction
The worldwide energy landscape is undergoing a transition towards a more sustainable energy provision. The pace of this transition is different in different parts of the world. The main goal of this survey paper, prepared under CIGRE JWG C2/B4.38, is to shed light on expected system operational challenges resulting from the change in the generation portfolio as part of the energy transition. These challenges were identified through extensive literature review and a number of surveys among and discussions with system operators throughout the world. The identified challenges were validated by transmission system operators (TSO) and as such pinpoints some of the research needs of the industry.

From system operation perspective, the main contributing factors identified with regards to this ongoing energy transition are threefold, as explained next.

Firstly, the transmission system connected conventional synchronous generator is rapidly being replaced by transmission and distribution connected variable renewable energy sources (RES) such as wind and solar generation. These are predominantly connected through power electronics (PE) converters. Figure 1 [1] illustrates for Ireland, UK, Denmark and Australia the evolution of the annual electrical energy production from coal, wind and solar photo-voltaic (PV). In this figure, 100% indicates the sum of the electrical energy production from coal, wind and solar. Other renewable as well as fossil fuel-based generation are omitted, as the sole purpose of this figure is to illustrate the relative development of the annual electrical energy generation from coal, wind and solar PV across different jurisdictions. It is observed that the combined annual electrical energy production from wind and solar PV already surpassed that of coal for Ireland, UK and Denmark.

Due to its intermittent and uncertain nature as well as its priority dispatch, these RES introduce a variable production pattern in the generation mix, resulting in a wide variety of operating conditions ranging from almost no conventional synchronous generation due to high RES production to conditions with no RES generation. High instantaneous levels of wind and solar generation relative to the demand are already being observed in Denmark (157%), South Australia (142%), Tasmania (70%) and UK (67%) [2], showing that the day-to-day observed share of RES is significantly larger than their share in the annual electrical energy generation.

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Additionally, markets with large penetration of RES tend to have more volatile prices, fewer periods in which conventional power plants can compete and, consequently, fewer running hours. This decreases their competitiveness in the day-ahead and intraday market and ultimately leads to the decommissioning of these conventional power plants.

Secondly, the regulatory framework influences the design, planning and operation of the power system. Network codes and other regulatory requirements need to continuously provide an adequate framework to

In Ireland, extensive technical analyses were conducted to guarantee operational reliability with increasing levels of power electronics interfaced generation (PEIG). The analysis revealed that for maintaining operational reliability the system non-synchronous penetration (SNSP), which is a measure to quantify the amount of non-synchronous generation at any instant in time, should be limited to 65% in 2019 for the All Island system (i.e. Ireland and Northern Ireland). As is shown in Figure 2, this limit was hit several times on 7 December 2019.

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1 - For more details on these analysis, please refer to [61]
facilitate the ongoing transition. A harmonized regulatory framework is imperative not only on transmission, but also on distribution level. Unfortunately, this evolves at a slower pace than the evolution of the system. An example in Europe is the System Operation Guideline.

Lastly, new transmission assets are realized in a rather slow pace due to increasing public opposition for new overhead lines and challenges associated with long underground cables. Such cables introduce new technical challenges for the design and operation of the circuits, e.g. harmonic resonance, temporary overvoltages and amplification of harmonic distortion. These phenomena require expensive and complex mitigation solutions that affect the reliability of the circuit [3]. The very long times required to build additional transmission capacity, increases the instances at which the system is operated closer to its security limits and with congestion management schemes.

Taking these observations into account, the energy transition poses important operational challenges for system operators, where the holistic question to be answered is: how should the future, low inertia power system be operated at an affordable cost, while guaranteeing at least today’s level of operational reliability?

One of the fundamental issues that first need to be addressed, is gaining insights in the operational challenges associated with the future power system. This is the goal of the current paper. Once addressed, a next step would be to identify how the PE technology used in e.g. HVDC technology and wind and solar PV generation can already support in mitigating some of these challenges. This is the topic of a future paper, which will also shed some light on future capabilities of PE based on ongoing developments as well as provide practical cases illustrating how different power electronics interfaced devices (PEID) are already being used to manage one or more of the identified operational challenges.

The remainder of the paper is organized as follows. Section 2 presents the identified operational challenges and groups these into three categories. Sections 3, 4 and 5 describe the issues of each of these categories and provide real examples where possible. Final conclusions and the way forward are presented in Section 6.

2. Identified Operational Challenges

Based on extensive literature review and surveys among and discussions with TSOs throughout the world, a non-exhaustive list of operational challenges resulting from the energy transition was developed. To the best knowledge of the authors, such a TSO-validated overview of challenges is rarely reported in academic literature. The identified challenges are grouped into the following three main categories:

• Category 1: New Behavior of the Power System
With increasing penetration of PEID, the power system behavior and response are bound to change. This category of identified issues focuses on new behaviors of the power system. An example of such a new behavior is lower resonance frequencies due to increasing HVAC underground cables.

• Category 2: New Operation of the Power System
This category of issues identifies areas where how we operate the power system needs to change. This includes the people, processes and tools in system operation that observe the bulk electric system and take necessary actions to maintain operational reliability. The new operation of the power system will require to increase the level of automatic control actions to cope with the expected faster and more frequent dynamic power system behavior. Some phenomena are expected to be too fast for a manual operational response.

• Category 3: Lack of Voltage and Frequency Support
Transient and steady state stability will remain crucial, i.e. frequency, synchronizing torque and voltage support requirements of the system will need to be maintained. This category deals with issues that result from lack of support for a stable voltage and frequency. An example is the increasing RoCoF resulting from decreasing conventional synchronous generation.

An overview of the identified challenges is given in Table 1. It is worth mentioning that an identified challenge might be linked to more than one of the predefined categories. In the overview below, an attempt is made to identify the most impacted category (i.e. Category 1, 2 or 3) for each identified issue. A description as well as accompanying references giving detailed explanations of these issues are given in the subsequent Sections.
3. Category 1: New Behavior of the Power System

The behavior of a power system can be described by its steady state and dynamic characteristics. The increased cabling, reduction of conventional synchronous generation and the increase of PEIDs alter the power system's behavior. This Section gives an overview of issues resulting from an altered behavior of the power system.

Resonances due to cables and power electronics

With increasing opposition for overhead transmission lines, more and more underground cables are being installed in the power system. Whereas overhead lines are inductive in nature, HVAC cables are capacitive. Inductive and capacitive elements in the grid can result in resonances, where the resonance frequency is inversely proportional to the capacitance and is defined as given in (1).

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Table 1: Overview of Identified System Operational Challenges
Technology-dependent impact: there is a positive effect on transient stability, if PEIDs are able to ride through faults and provide fast voltage support;

Penetration level-dependent impact: while a moderate penetration level of PEIG can improve transient stability due to decreased loading of conventional synchronous generators, decreased loading of transmission lines and additional voltage support by PEIG, a higher penetration can reverse this impact. It was shown in [9], [10] that when PEIG penetration increases, the critical clearing time (CCT) indeed decreases. This is illustrated in Figure 4 Critical clearing time (blue) under different levels of PE penetration [9] (blue graph). The yellow graph illustrates that parameter tuning can enhance the transient stability. The CCT is the maximum duration for which a disturbance can be applied without the system losing its stability. When the disturbance is cleared after the CCT, conventional synchronous machines lose synchronism and the system becomes unstable. CCT is an indicator for transient stability;

Pre-fault operating point-dependent impact: the pre-fault loading of synchronous generators and transmission lines affects transient stability margins (cf. penetration level-dependent impact). Likewise, the loading of PEIG is relevant. Their voltage support contribution, which has a positive effect on transient stability, can in most cases not exceed the rated current of the converter. Therefore, lower loading of the PEIG enables better voltage support as it would not require a reduction in the active power output of the PEIG;

Location-dependent impact: PEIG installed electrically close to synchronous generators can increase transient stability by voltage support in case of faults. The further away the PEIG is installed, the lower its voltage support and hence the short-circuit power at the synchronous generator’s connection point;

As a result, resonance points of the power system shift to lower frequencies with increasing cable lengths [4], which could lead to high over-voltages and possible damage of power system components. In [5] studies were performed to verify the immunity of the Dutch transmission network against long HVAC offshore cables, needed for the connection of wind farms. It was found that the connection of such a cable introduced a low-frequency resonance close to 100 Hz, see Figure 3.

In addition to cable resonances, an increase of harmonic currents due to the combination of additional HVAC underground cables and the harmonic voltages emitted by PE is of concern to TSOs [6]. System damping has to be implemented. Active damping is preferred to passive damping so as to improve the efficiency of the conversion. In addition, paralleled grid-connected inverters in photovoltaic (PV. Whereas this should be mitigated in the planning stage during the design process, it is stressed that not all operational conditions (different permutations of network topology, maintenance schedules and different load and generation patterns) can always be covered in the planning stage. Therefore, residual risks might require specific harmonic assessments in the operational planning stage.

Reduction of transient stability margins

Transient stability is concerned with the ability of synchronous machines to maintain synchronism after a severe disturbance. According to [7], [8] increasing PE penetration affects transient stability in various, interdepending ways, and whether the absolute impact is negative or positive depends on the superposition and interaction of these influencing factors:

\[
f_r = \frac{1}{2\pi \sqrt{LC}}
\]

\( f_r \): resonance frequency (Hz)
\( L \): inductance (H) observed at the point of interest
\( C \): capacitance (F) observed at the point of interest

Figure 3 Harmonic frequency scan at the point of interconnection [5]

Figure 4 Critical clearing time (blue) under different levels of PE penetration [9]
• Control system-dependent impact: voltage support provided by PEIG during fault can improve transient stability. The higher the terminal voltage of synchronous generators during and after faults, the higher the electrical torque which leads to a lower acceleration during faults and a higher deceleration afterwards.

Studies performed in [10] on the IEEE 9 bus system revealed that tuning of the reactive current boosting gain $K$ in the converter control of the PEIG increased the critical clearing time and therefore enhanced the transient stability of the considered power system. For the IEEE 9 bus system, the result of $K$ on the critical clearing time is given in Figure 5. Through tuning of this gain, the penetration of PEIG was successfully increased from 57% to 78%.

Resonance (harmonic) instability

Converters are equipped with a multi-timescale control system for the regulation of the active and reactive power output [11]. The multi-timescale dynamics of the converters results in cross coupling with the electromechanical dynamics of electrical machines and electromagnetic transients of the grid, which can lead to oscillations across a wide frequency range, from sub synchronous to super-synchronous [12], [13]. Furthermore, small-signal dynamics of converters may introduce negative damping across different frequencies. Negative damping destabilizes the natural frequencies of the power system, resulting in resonance (or harmonic) instability [14]. Negative damping in the high frequency range is introduced e.g. by the time delay of the digital control systems or due to the frequency-coupling mechanisms of the switching modulation and the sampling process. Negative damping in the low frequency range results from e.g. the PLL of inverters or the constant power control of rectifiers. The Dutch-German TSO TenneT observed resonance instability involving HVDC converters of the BorWin1 wind farm already in 2013 [15]. The frequency range of different harmonic phenomena related to PEID and based on a 50 Hz fundamental frequency, is given in Figure 6 [16].

![Figure 5 Critical clearing time corresponding to different values of K](image1)

![Figure 6 Frequency range of different harmonic phenomena](image2)
Sub-synchronous controller interactions (SSCI)

In literature, sub-synchronous controller interactions (SSCI) is used to describe the following three distinct phenomena:

i. The interaction between a doubly-fed induction generator (DFIG) based wind farm and a series capacitor compensated transmission line;

ii. The interaction between a voltage source converter (VSC) of e.g. a direct-drive permanent magnet synchronous generator (D-PMSG) and a weak grid, and

iii. The interaction among VSCs.

These adverse interactions are electromagnetic in nature and have a faster response than classical sub-synchronous oscillations [17], [18].

The first type of SSCI occurs when the sub-synchronous resonance frequency of the series capacitor compensated system gets excited. The resulting oscillations are then amplified by the DFIG wind farm. This issue was first observed in Texas in 2009, where a fault resulted in the radial connection of the wind farm to a series compensated transmission line. Undamped oscillations of around 20 Hz were observed (Figure 7) and the excessive currents significantly damaged the wind turbines [19]. Other practical cases of this form of SSCI are reported in [20]–[24].

For the second SSCI type, a D-PMSG is considered in which the generator is decoupled from the grid through the DC link. The VSC behaves like a capacitive reactance with negative damping and combined with weak grid conditions (i.e. high equivalent line inductance L) this results in low resonance frequencies. If these resonances are excited, the oscillations will be amplified by the VSC. Practical cases are reported in [25]–[27]. Finally, there is only one practical case reported in academic literature on SSCI resulting from the interactions between converters.

This event occurred between a STATCOM and a wind farm in China, where both devices tried to regulate the voltage at the point of interconnection [28].

These SSCI issues should also be mitigated in the design stage. However, due to the complexity to cover all operational conditions, additional operational constraints could be defined, such as monitoring these phenomena in the operational planning stage or restricting certain high-risk operational conditions. The need to assess the interactions in operational planning is further increased as detailed models of PEIDs are only available after their commissioning.

Introduction of new low frequency power oscillations

In a power system multiple local or global power oscillations can exist between synchronous machines. These oscillations occur at different frequencies, each with their own damping ratio. The occurrence of such oscillations, combined with insufficient damping can lead to (cascaded) generator tripping, which eventually could jeopardize system stability. The frequency and damping of each oscillation depend on the system configuration as well as the type and location of power plants. When PEIG replaces synchronous machines, the associated power system stabilizers are also lost, potentially resulting in decreased damping of existing modes. Furthermore, the new configuration (i.e. new generation and associated controls) introduces new modes in the power system, which may or may not be sufficiently damped.

Voltage dip induced frequency dip

This issue refers to the recovery phase of the active power of wind turbine generators after short-circuit events [29]. This active power recovery may be slow in order to limit the mechanical stress on the drivetrain. Figure 8 shows an actual recording of the response of a wind farm to a
Operation of protection relays

Sufficient fault current is needed to enable the correct operation of protection systems (primary and/or backup), including those located in distribution networks. Within the MIGRATE project [33] the influence of increasing levels of PEID on the operation of differential protection, distance protection and over-current protection was investigated. It was found that the distance protection would be impacted the most. Extensive analysis and (real-time digital) simulations showed that by increasing PEID penetration, distance protection experiences difficulties to identify and detect some faults and under specific circumstances may not operate. System integrity protection schemes were also found to be less reliable under high PEID conditions.

On the other hand, over-current protection may operate far more slowly than intended or will not be triggered at all when fault currents are insufficient. Figure 9 [30] qualitatively illustrates the impact of reduced fault

![Figure 8 Energy deficit caused by slow recovery of wind generation following a network disturbance](image)

**Figure 8** Energy deficit caused by slow recovery of wind generation following a network disturbance [30]

system fault in Ireland [30]. The active power recovers to the pre-fault value in approximately one second after fault clearance. The greyed area represents the energy deficit with respect to a synchronous generator, which would recover active power almost instantly upon fault clearance. This energy deficit can represent a threat to frequency stability in scenarios of high penetration of wind generation depending on the system’s size and characteristics, as illustrated in [31]. In [32] an adaptive priority based reactive and active current injection control strategy is proposed to overcome the voltage dip induced frequency dip.

This issue is mainly found in DFIG wind turbines. In D-PMSG wind turbines this issue can be eliminated by using a chopper in the DC link that dissipates the extracted energy from the wind turbine during grid faults. As a consequence, the wind turbine drive train is not offloaded during a grid fault and therefore there is basically no mechanical stress on it.

![Figure 9 Protection Activation vs Fault Level: Synchronous Generation versus PEIG](image)

**Figure 9** Protection Activation vs Fault Level: Synchronous Generation versus PEIG [30]
current contribution from PEIG on the operation of over-current protection relays.

Larger voltage dips and larger propagation of low voltages during disturbances due to reducing system strength

Periods of high RES generation are likely to coincide with minimum online conventional synchronous generation, whereas low RES conditions will require increased online conventional generation. Such periods of high RES infed will result in lower short-circuit power levels across the network, which will be observed during real-time operations. Compared to historical operating conditions, this could result in reduced dynamic voltage support, larger voltage dips and more widespread propagation of low voltages across the system during a network disturbance.

LCC commutation failure due to reducing system strength

For line-commutated converter (LCC) HVDC, the chances for commutation failure increase significantly if voltage depressions in any phase at the connection point are more than 20%. On the other hand, if the voltage depressions in any phase are less than 10%, the probability of commutation failure remains very low [34]. Weak systems are prone to voltage depressions and as a result, LCCs are exposed to an increased risk of commutation failure. Commutation failures can lead to large active power oscillations in the remaining part of the network.

4. Category 2: New Operation of the Power System

This Section gives a brief description of the issues related to the category “New Operation of the Power System”. This includes the people, processes and tools in system operation that monitor the bulk electric system and provide decision support regarding necessary actions to maintain operational reliability.

Increased congestion / Decrease of redispatch possibilities

Large scale wind generation is often connected to the transmission system at locations remote from load centers, resulting in high cross-zonal power flows. Without proper network investments, utilization of the existing transmission system increases, leading to operating the power system closer to its security limits. This higher utilization results in a more congested network. Furthermore, as PEIG usually has priority dispatch and is replacing conventional generation, the possibilities for redispatch, when congestion does occur, is reduced. Combined, this leads to increased congestion costs [35], [36].

An example of the congestion management costs for different amounts of the wind generation in Germany is given in Figure 10 [37] and their allocation and policy implications in both countries. Since 2010, system operation costs have increased by 62% in Britain (with a five-fold increase in VRE capacity). From this figure, a linear relationship between the PEIG penetration and its curtailment rate is observed.

Furthermore, this work also investigated the possible existence of a dependency between PEIG penetration and its curtailment rate. This dependency is illustrated in Figure 11 [37] and their allocation and policy implications in both countries. Since 2010, system operation costs have increased by 62% in Britain (with a five-fold increase in VRE capacity for Germany and Britain). From this figure, a linear relationship between the PEIG penetration and its curtailment rate is observed.
Observability and Controllability of RES

In conventional power systems, controllability and observability of generators were rather straightforward, as there were lower number of conventional power plants that were generating majority of the electrical energy. With electrical energy increasingly being supplied by a large number of (distributed) RES, observability is key in maintaining system security: improved observability of RES at national and regional scale enables proper anticipation of issues with regards to supply-demand balance and flows on the grid. Controllability of these resources is required in order to actually act on the anticipated issues.

In Spain, a dedicated control center for RES, the CECRE [38], receives every 12 seconds tele-measurements from renewable generation facilities, or group of facilities, with a power capacity greater than 5 MW, reaching an observability of 100% of wind and 84% of solar PV generation. CECRE also sends active power set points reaching a controllability of 99% of wind and 47% of solar PV generation.

Increased vertical coordination: TSO-DSO

With increasing shift of generation from transmission to distribution level, the DSO possesses increasingly significant resources (e.g. provision of black start support, voltage regulation, balancing power, etc.). In order to maintain adequate operation of the system, coordination between TSO and DSO is of utmost importance. Increased data exchange between TSOs and DSOs should enable increased observability and coordinated controllability of available flexible resources at both the transmission and distribution level. Data quality of the large volumes of exchanged data should go hand-in-hand with improved decision support tools.

Increased horizontal coordination: TSO-TSO

For highly meshed grids, an improved regional cooperation and coordination in all operational processes and timeframes is of key importance to resolve operational challenges. Cooperation and coordination among Member States in Europe is being prescribed in the risk preparedness regulation [39], where scenarios on how to deal with crisis events from a regional perspective are developed. In Europe, regional security coordinators support TSOs in the regional operational planning. An example where coordination is key, is the optimal use of the multiple phase-shifting transformers across Continental Europe. The penetration of RES might further increase the need to coordinate on more topics than today (e.g. voltage and stability management).

In North America, coordination among the Reliability Coordinators is prescribed in Standard IRO-014-3 [40]. It aims at preserving the reliability benefits that come from interconnected operations, while ensuring that each Reliability Coordinator’s operations are coordinated such that they will not adversely impact other Reliability Coordinator Areas.

Operation of hybrid HVAC-HVDC systems

System operators are accustomed to operate traditional power systems, where all concepts (e.g. balancing mechanisms and redundancy concepts) have been developed based on the traditional power system components and their behavior. Operators have limited experience with HVAC-HVDC hybrid systems, e.g. whereas the power flow through an AC line would change following a disturbance, this is not the case for a HVDC link for which the power flow is fully controlled. The operational framework for hybrid systems is developing concerning coordinated operation processes, power flow control capabilities, and integration in capacity calculation.

When a synchronous system has multiple HVDC lines within the same and across bidding zones, an optimization is needed to identify the optimal injection of each HVDC line, taking into account system losses, contracted transmission capacities, network security limits and the power balance. Multi-zonal systems and the coexistence of regulated operators with private infrastructure developers with distinct aims further complicate such an optimization, as different operators can have different optimization targets [41]. System operators will need to invest in such optimization tools. References [42], [43] present different examples of optimizations in hybrid AC/DC systems. To account for parallel flows created by conflicting settings of HVDC lines, adequate flexibility will be needed.

Operators will need to be equipped with more skills

Operational personnel will need to be trained on PEIDs in the power system and understand how, when and why
they interact with the rest of the power system. They will also need to be trained on the operational freedom and capabilities that are provided by PEIDs. Knowledge on more general topics such as system stability will be beneficial to fully utilize PEIDs to their full extent.

**Power system restoration services**

System operators have as common practice to use conventional power plants for restoration after a blackout, which makes the process rather stable and predictable. An overview of power system restoration strategies across the world is given in [44]. In a future with less conventional synchronous generators, it is important to redesign the restoration strategies, by making use of all technologies available in the power system with the capability to provide restoration support, i.e. blackstart capabilities and frequency and voltage support. Due to the fact that the share of RES in distribution networks is nowadays significant with the tendency to grow, there is a need for TSO/DSO integrated restoration plans, which will involve increased coordination, information exchange, joint operator training, and most likely common tools.

In general, PEIDs have advanced control possibilities that can be used and further developed to enhance system operation and network security, such as continuous voltage control, synthetic inertia, system restoration services and power oscillation damping. In an environment with high penetration of power electronics, devices such as LCC and VSC HVDC, Battery Energy Storage Systems (BESS) and PEIG can play a relevant role in power system restoration. LCC can be used in the bottom-up restoration strategy and VSC HVDC can be used both for both, bottom-up and top-down restoration strategies. BESS, on the other hand, can be used in several ways for supporting the restoration process [45]. In [46] the participation of storage in the load restoration is discussed. An operating strategy for BESS as both load and generator during restoration is proposed in [47]. And finally, when distributed PEIGs are used during restoration, they can speed up the initial phases of the load pick up in the restoration process. This is illustrated in Figure 12 Evolution of the restoration process in function of distributed generation penetration rate [48], where the evolution of the restoration is given for different shares of distributed generation that are participating in the restoration process.

**5. Category 3: Lack of Voltage and Frequency Support**

This Section gives a brief overview of issues that are originating as a result of decreased availability of ancillary services.

**Increasing RoCoF**

The increasing penetration of PEIG translates in decreasing synchronized system inertia, which in turn results in increasing rates of change of frequency (RoCoF). Higher RoCoF values

- will lead to more frequent activation of anti-islanding protection for high RoCoF events; and
increase wear and tear and failure of conventional generators due to pole slips. To minimize the possibility of damage, the generator will trip almost without time delay.

When such events occur, cascading events could follow and lead to a blackout.

Effort should be dedicated to investigate how to limit the RoCoF increase on the one hand and on the other hand how to make conventional generation withstand increasing RoCoF values.

**Decreasing frequency nadir**

The frequency nadir measures the minimum post contingency frequency and is the result of the combined effect of system inertia and governor (primary) response. With reduced inertia and unchanged governor response, the nadir will be lower. The consequence of a lower frequency nadir is the faster and more frequent activation of under-frequency load shedding schemes.

Figure 13 [49] illustrates how the frequency behaves after a disturbance, when the amount of kinetic energy (proportional to inertia) in the system varies. It can be observed that higher kinetic energy in the system results in a lower RoCoF and a higher nadir (approx. 48.8, 49.02 and 49.15 Hz for respectively 100, 200 and 300 GWs). The role of frequency containment reserves (FCR) in arresting the declining frequency is also highlighted.

**Excessive frequency deviations**

Any power imbalance results in a change of the system frequency. As the consequence of electromagnetic forces, the rotational speed of synchronous generators is an exact representation of the system frequency. In case of excess generation, the generators are accelerated and system frequency increases (and vice versa in case of excess load). Decreased system inertia means that this process will be faster and more frequent, which causes stress on synchronous machines and jeopardizes the capability of the system to maintain stability. This is confirmed by a study performed on the Irish transmission system. In this study, the frequency variations resulting from wind generation in today’s power system (with 60% of PEIG) was compared with the expected variations based on the wind generation in 2040 (with 80% of PEIG) [50]. Figure 14 [50] shows some of the results of this study.

An observation from this figure is that the absolute deviation of the frequency from its nominal value
demand that needs to be supplied by transmission and sub-transmission systems at various times of the day. Operation of transmission lines below their surge impedance loading (SIL), coupled with the increased usage of underground cabling, will result in a surplus of reactive power and an increase in network voltages during these low demand periods. The ability to ‘sink’ excess reactive power at such times is a growing issue in some networks.

Figure 15 illustrates the change in minimum reactive power demand for the power system of Great Britain from 2005 to the start of 2016 [57]. The changing power factor characteristics of loads (linked to e.g. consumer electronics), increased RES, and reduced transmission system demands are combining to result in an excess of reactive power that needs to be absorbed to avoid long term (sustained) over-voltages. The risks associated with not doing so include unexpected disconnection of generation which could manifest into frequency stability problems, e.g. in Canada, PEIG equipped with high voltage protection may trip for voltages exceeding 115%.

Another issue is the lack of reactive power, which is normal in systems where a high share of RES is connected at distribution level (like in Ireland) and operated at fixed leading power factor, i.e. absorbing VARs. This creates a high demand for reactive power, which needs to be supplied from the transmission system and, in some cases, requires installation of reactive support devices at transmission level. Note that the traditional sources of reactive power (i.e. synchronous generators) are now replaced with RES, for which reactive power capabilities cannot always be utilized.

Dynamic reactive power balance

For disturbances, sufficient reactive power is necessary to recover system voltages back to acceptable limits, as well as prevent the propagation of low voltage conditions increases when the PEIG penetration increases. In the 60% case, this deviation was 50 mHz, whereas it increased to 90 mHz in the 80% case. In both cases, the deviation remains below the maximum acceptable deviation of 200 mHz.

In order to adequately balance the system frequency, correct estimation of operating reserves remains of utmost importance.

Correct estimation of operating frequency reserves

Operating frequency reserves consist of regulating, following, contingency and ramping reserves or primary control, secondary control and tertiary control reserves [51]responsive load, and storage. These are important tools for system operators to address uncertainty and variability in generation and demand, that otherwise exist due to:

- Forecast errors in predicting RES generation;
- Variability in RES generation (inherent characteristic);
- Unplanned outages of generation.

High forecast errors in predicting RES generation require increased regulating reserve capacity (in MW). Therefore, efforts spent in reducing these errors will be paid off by less required reserves. On the other hand, the inherent variability in RES generation leads to more frequent activation of regulating reserves, thus resulting in increased use of regulating reserve energy (in MWh). The dependency of the operating reserves on the forecast accuracy and variability makes the reserves requirements time dependent. Whereas the current practice for dimensioning reserve requirements is primarily deterministic, probabilistic methods are proposed in [52]–[56].

Static reactive power balance

RES connected close to customer loads at medium and low voltages are contributing to a reduction in demand that needs to be supplied by transmission and sub-transmission systems at various times of the day. Operation of transmission lines below their surge impedance loading (SIL), coupled with the increased usage of underground cabling, will result in a surplus of reactive power and an increase in network voltages during these low demand periods. The ability to ‘sink’ excess reactive power at such times is a growing issue in some networks.

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From this figure it is clear that ramping requirements will become more demanding over time. In cases where the existing generation portfolio is not able to manage such ramps, adequate ancillary services will be needed to meet the ramping requirements and maintain operational reliability.

6. Conclusions

The aim of this paper was to identify operational challenges and requirements that arise due to the energy transition into a RES dominated power system. The energy transition impacts system operation in three ways. Firstly, conventional synchronous generation connected at transmission level is increasingly being replaced with power electronics interfaced generation at both, transmission and distribution level. Secondly, the regulatory framework, which evolves rather slow, influences the design, planning and operation of the power system. And lastly, the long lead times associated with the construction of new transmission assets require more frequent operation of the system closer to its stability limits.

Based on extensive literature review and two surveys, CIGRE JWG C2/B4.38 grouped the identified issues in three main categories. The first category groups together issues that exhibit a new behavior of the power system. The second category deals with issues related to new operational practices required for maintaining operational reliability. The third category describes issues originating from the lack of support for a stable voltage and frequency. The identified challenges are validated by system operators and as such will hopefully give guidance with regards to some of the research needs of the industry.

The next step is to identify how power electronics technology available in HVDC and PEIG can already support in mitigating some of these challenges and guaranteeing system security.
7. Acknowledgements

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8. References


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1. Introduction

Due to the accelerated shift towards a carbon-free electrical energy system, the power system is changing in terms of both planning and operation with an increasing integration of converter-interfaced renewable generation at all voltage levels. One area strongly affected by these changes is power quality where, if not managed correctly, the result can be equipment mis-operation, accelerated aging, tripping of plant, loss of production process, etc. Failure to provide adequate supply quality can have negative impact on system operators, including customer complaints, reputational damage, financial liability and regulatory penalties.

The issue of power quality in power systems is not new, with some publications dating back to the early 1900s dealing with distorted waveforms in transmission lines and their effects on transformers, rotating machines and telephone interference. Significant efforts were devoted at that time to investigate, understand and mitigate their negative effects. Standardisation was introduced throughout the years to control and limit different power quality parameters resulting in positive effects.

This picture is changing rapidly. Power systems globally are experiencing a transition towards decarbonisation of electricity production through large-scale deployment of central and distributed renewable energy sources (RES), which are gradually replacing conventional thermal plant. The connection of RES to the power system is mostly achieved using power electronic (PE) converters. Equipment interfaced through PE-converters can have both a positive or negative effect on power quality, depending on the type of disturbance evaluated and the applied control strategy of the PE-converter [1].

Presently, the understanding of the impact of PE-converters and some related phenomena is not fully developed. However, it is widely accepted that the consequences of degraded power quality can have severe financial implications and most studies in the US and Europe point to an excessively high level of cost if serious problems arise [2]. This paper intends to provide a high-level summary of power quality issues in this changing environment and by doing that raise awareness of the main facets of power quality.

2. Harmonics

Harmonics can be present in voltage and current waveforms, being defined as “a sinusoidal component of a periodic wave or quantity having a frequency that is an integral multiple of the fundamental frequency”. Special sub-categories exist including interharmonics, defined as “a sinusoidal component at frequencies that are not integer multiples” and subharmonics “a sinusoidal component at frequencies below the fundamental”. Harmonic distortion is caused by non-linear devices connected to the power system. Unlike linear devices, a non-linear device reacts to a perfect sinusoidal voltage waveform with a distorted current. In Figure 1 harmonic measurements obtained at a 15 kV busbar in Denmark is shown. Figure 1 (a) shows the time domain waveform at the location of the arrow, Figure 1 (b) shows the frequency domain harmonic decomposition per phase at the same location and Figures 1 (c) and (d) shows 11th and 13th single harmonic components as function of time measured over 3 weeks.

Historically, control of harmonic at all levels has been an important issue requiring system studies, application of standards, and implementation of mitigation measures. The deleterious effects of harmonics have been kept under control because of this coordinated approach. Currently, the widespread connection of PE-converters at all voltage levels is driving new concerns and interest on the topic of harmonics. Furthermore, the planning and design methods utilized in the past may need to be updated as a consequence of the new types of equipment connected to the power system.
there still exists a margin between the harmonic voltage distortion at the wall outlet and the prescribed limits [4].

Emphasis on limitation of harmonic emissions is gaining more attention [5]. This leads to an opposite trend that harmonic emission of new plant, as a whole, is reduced due to more strict enforcement of grid code requirements and to a trend of lower emission at individual equipment level. At equipment level different control strategies and converter topology, as for instance multi-level converter, are utilised with the combined effect of low emission of harmonics. Also, increased use of more energy efficient equipment with a resulting low load current implies that the harmonic contribution of for instance lighting equipment less of a concern [6].

Concurrent with the connection of more converter-interfaced equipment, power cables are seeing increased use at all voltage levels in some countries. Due to the electrical parameters of the cable, circuit resonance frequencies may be shifted to lower frequencies which increases the risk of amplification of pre-existing harmonics [7], [8], [9]. This phenomenon has been observed at different voltage levels in several countries, but it has proved to be especially problematic at higher voltage levels, where it introduces a limitation on the share of cable that can be safely installed and operated without introducing a risk of excessive amplification of harmonics [10]. An example of amplification of the 11\textsuperscript{th} order harmonic voltage in a 400 kV substation in Denmark caused by the commissioning of an 8 km 400 kV cable situated 90 km away from the substation.

2.1. Trends and Challenges

It is generally expected that power systems around the world will experience an increase in harmonic distortion as the green transition progresses [1], [3]. Today, low-order harmonics are still the dominant harmonics in most power systems due to the characteristics of existing equipment. However, due to advances in technologies, harmonics generated by modern PE-converters also include the high-frequency harmonic range (>2 kHz), and the term suprapharmonics is increasingly used to define this range of harmonics. As well as the appearance of high frequency harmonics, there are also indications of increased emission of interharmonics and even harmonics (not necessarily attributed to PE converters), but a complete overview of these trends remains missing.

Drivers for this trend at high and extra high voltage include not only the integration of RES connected via PE-converters, but also increased connection of FACTS controllers, HVDC links and general proliferation of PE converters in the demand, such as large data centres and large industrial plants. Also, at lower voltage levels an increase in harmonic generation is expected, caused by widespread photovoltaic (PV) generation, usage of energy storage, electric vehicle charging/discharging and increasing converter-interfaced loads at domestic level. This can eventually set a limit to the hosting capacity of the distribution grid for unmitigated installations. Presently, a recent mapping, including 163 measurement location in 17 countries, admittedly incomplete but still giving an indication, shows that at most locations there still exists a margin between the harmonic voltage distortion at the wall outlet and the prescribed limits [4].

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3. Voltage variation

The quality of the voltage waveform can also be measured in terms of its magnitude and temporal deviations with respect to the nominal parameters. A distinction can be made between steady-state values, with an acceptable variation of ±10% of nominal typically, and short-term events for which higher deviations are acceptable. In Figure 3 Excessive voltage oscillations following fault clearance due to the response of solar farms’ control systems a fluctuating voltage waveform is presented as an example.

3.1. Trends and Challenges

Steady state refers to slow variations in the RMS value of the voltage waveform which take place throughout the day due to gradual customer load variation or variable RES output. A trend towards larger and more frequent voltage variations can be expected due to increasing penetration of intermittent generation resources such as wind and solar. Such voltage variations can lead to both under voltage and over voltage where both situations can have an impact on network operation and on customer equipment.

In distribution networks, over voltage can lead to excess energy consumption depending on the type of load, core saturation of transformers and stressing of insulation leading to its premature failure. Under voltage can lead to reduced energy consumption depending on the type of load, malfunctioning of high-intensity discharge lamps and reduction of torque developed by mains connected motors. Undervoltage can also result in overcurrent, as equipment often consumes a constant power, with accelerated ageing as a consequence. These slow variations are normally managed by automatic or manual control actions taken by the grid controllers to ensure compliance with statutory voltage quality standards. However, the increased level of wind and solar is introducing significant challenges in the design and operation of these networks.

With the proliferation of rooftop solar PV systems in low
new system services. The objective is to incentivize wind farm owners to invest in technologies capable of providing enhanced voltage and reactive power control performance over and above the minimum grid code requirements with the introduction of new products such as Steady State Reactive Power (SRP) [12] - other countries are following this trend.

**Short-term voltage variations** refer to rapid voltage changes and voltage dips, typically caused by connection and disconnection of loads, network switching operations, electric arc furnaces, transformer energization, motor starting and system faults.

One of the main concerns with fast voltage variations at low voltage levels is the resulting lamp flicker which can be problematic in distribution systems. The proliferation of converter-interfaced renewable generation connections, with intermittent power output, combined with a reduction in system strength through displacement of conventional plant, results in a higher volatility in the system voltage at transmission level. Therefore, fast voltage variations can now become also prominent at high voltage levels.

The trend towards reduction in system strength at transmission levels means that voltage dips, typically caused by system faults, transformer energisation or large motor starting, can become more frequent and severe and will also propagate to downstream distribution networks [1]. If large shares of converter-interfaced generation get disconnected from the grid during a voltage dip, the initial voltage disturbance will evolve into a large power imbalance introducing a risk to the stability of the system frequency, which could result in a system blackout. Fault Ride Through (FRT) requirements for converter-interfaced generation have been introduced in many countries to address this challenge. In most grid codes, these requirements include not only the need to remain connected during the voltage dip but also the provision of reactive current in an attempt to support the system voltage and limit the extent and magnitude of the disturbance.

Fault Ride Through (FRT) requirements for converter-interfaced generation have been introduced in many countries to address this challenge. In most grid codes, these requirements include not only the need to remain connected during the voltage dip but also the provision of reactive current in an attempt to support the system voltage and limit the extent and magnitude of the disturbance.

Grid-connected converters in modern power systems are designed to provide specific functionality. Typically, the voltage and power control loops, as well as the grid synchronization control, are cascaded with the current control. The cascaded control system is characterized
and duration of the event, voltage oscillations can in turn manifest in power quality indices; e.g. as flicker due to rapid voltage variations. As an example of this new phenomenon, Figure 3 shows the simulated sustained voltage oscillations following a credible system network fault taking out a transmission line being the key source of system strength support for the inverter-connected generator under consideration. These types of oscillations have already been observed in practical power systems involving two or more inverter-based resources. An example of measured flicker during a sub-harmonic interaction event is shown in Figure 4. These oscillatory responses cause the inverter-based resources to breach of their technical performance requirements. Undamped and sustained oscillations are inconsistent with the definition of adequately damped oscillation and cause short-term flicker levels well in excess of the maximum permissible level of 1.0 as per [14].

Figure 3 Excessive voltage oscillations following fault clearance due to the response of solar farms’ control systems

Figure 4 Measured short-term flicker (Pst) level due to an adverse sub-harmonic interaction
3.2. Opportunities

Low voltage (LV) systems operating at the high end of the allowable voltage range can lead to increased energy consumption depending on the types of loads, stressing of connected equipment and tripping of connected PV systems thus defeating the purpose of investment of the PV systems. Compared to older solar PV inverters which operate at unity power factor, the newer inverters are able to control the voltage at the point of connection through reactive power absorption or injection. While such approaches are not mandatory at this point in time in many countries and the owners of the PV systems would like to benefit from the maximum real power injection, there is an opportunity to utilize new equipment capabilities to support the system in a cost-effective manner.

The network wide deployment of low voltage STATCOMs which are able to manage the steady state and dynamic voltages in LV networks are now being trialed in some countries such as Australia [15]. Studies are still required to investigate the effects on the overall network energy savings by employing such network wide solutions and the associated incentive schemes required to drive that investment.

There are also opportunities for enhanced co-ordination of voltage control strategies and share of reactive power resources between TSOs and DSOs. Some interesting examples and proof of concept of co-ordinated approaches are described in [16], including the deployment of voltage controllers in large DERs clusters in Ireland, Spain and Germany.

Most of the challenges associated with integration of converter-interfaced renewable generation relate to the displacement of conventional plant and reduction in available dynamic reactive power resources to provide voltage regulation. Furthermore, fluctuations in power output caused by local weather conditions (e.g. wind speed or sun radiation) can cause additional voltage variations outside the continuous operational range. Power electronics, however, can help to mitigate these issues through fast controls that can respond to voltage fluctuations or sudden changes in reactive power profile in less than a cycle. While minimum performance requirements can be introduced in grid codes to utilize these new functionalities, there are also opportunities for the development of new market products to incentivize investment in new functionalities that provide benefits to the overall power system.

With regard to new phenomena, there are several possible ways to optimize the power system design and operation to reduce (or even completely avoid) grid-connected converter instability and therefore related power quality issues. One can distinguish four main methods of converter instability mitigation in power systems:

- tuning of converter control parameters to increase the robustness,
- placing passive filters to attenuate unwanted resonances,
- adjusting the power system operational philosophy to avoid critical topology changes,
- providing additional active damping within the sensitive frequency range.

4. Voltage unbalance

Voltage unbalance is defined as a "condition in a poly-phase system in which the magnitudes of the phase voltages and/or the phase angles between consecutive phase voltages, are not all equal [17]. Such three-phase unbalanced voltages can be decomposed into three balanced systems, namely: positive sequence, negative sequence and zero sequence. For a three-phase system, the degree of unbalance is generally expressed as the ratio of the negative- and zero-sequence components to the positive-sequence component. The negative-sequence component is normally the main concern considering the impact on three-phase rotating machinery and hence unbalance usually refers to negative sequence unbalance.

Figure 5 shows actual recorded three phase voltages at a 150 kV substation measured over a period of 2 weeks with the corresponding positive sequence voltage, negative sequence voltage and voltage unbalance factors.

To understand this in practice, the example of a three-phase induction motor can be used. The positive-sequence set of voltages will drive the motor in a particular direction of rotation whereas the negative-sequence set of voltages will work against this direction of rotation, as two counter-rotating magnetic fields are created in the induction motor. Even with a relatively small negative sequence voltage, the resulting negative sequence current in a three-phase induction motor can be shown to be relatively large. As a consequence, induction
motors will experience excessive stator and rotor heating, torque ripple (at twice the supply frequency) and hence noise and vibration and sometimes leading to premature failure. For this reason, induction motors need to be derated under voltage unbalance conditions [18]. A similar type of impact can take place in synchronous machines if they are connected to networks with voltage unbalance, and for this reason limits exist on allowable network voltage unbalance under both normal and contingency conditions. Furthermore, voltage unbalance can also lead to the generation of uncharacteristic harmonics by three-phase rectifier systems which form the front end of many AC variable speed drives.

Voltage unbalance in electricity networks is primarily caused by asymmetrical three-phase loads, unequal distribution of single-phase loads (especially in low voltage distribution systems) and asymmetrical transmission and distribution lines. The latter is due to the asymmetry introduced by the electromagnetic coupling between the different phases on one circuit but also between two circuits on the same tower or right-of-way. Although low voltage distribution lines which are relatively short are not transposed, long high voltage lines normally are transposed.

### 4.1. Trend and Challenges

Proliferation of technologies such as photovoltaic systems at the LV level is taking place as single-phase connections. Depending on the geographic availability of three-phase connections, single-phase PV connections can be altered between the phases but in places where only single-phase laterals are available, all connections end up on the same phase which can lead to significant voltage unbalance levels on three-phase LV systems. Other technologies that will have an impact include electric vehicle charging points and heat pumps at the low voltage level. These will have an increased level power capacity and are likely to introduce more voltage unbalance and hence their capacities may be limited depending on the fault level at the point of connection. Due to time intermittency of such loads, distributing them among the available phases is not expected to lessen the effect substantially.

Large scale wind and solar farms are often connected at remote locations supplied by relatively long untransposed lines, and hence voltage unbalance can arise due to the lines [19] although the wind or the solar farms inject balanced currents.

### 4.2. Opportunities

With single-phase PV connections, their capacities need to be controlled in comparison to the fault level at the point of connection and their distribution across the phases by setting appropriate guidelines, rules and regulations. These limiting capacities need to be determined through extensive studies covering typical networks. An example is shown in [20].

With regard to large solar and wind farm applications that are connected at the end of relatively long untransposed lines, to mitigate or reduce the resulting voltage unbalance, instead of using dedicated network STATCOMs, the power electronic inverters within the

![Figure 5 Unbalance between magnitudes of the three phases: (a) phase voltages, (b) positive sequence voltage, (c) negative sequence voltage and voltage unbalance factor.](image-url)
solar and wind farms may be able to compensate such
effective generation resources such as wind and wind, and response of associated control
systems. Such voltage variations can lead to both under
voltage and over voltage where both situations can
have an impact on network operation and on customer
equipment. Reduced system strength at transmission
level means that voltage dips, typically caused by system
faults, transformer energization or large motor starting,
can become more frequent and severe and they will
also propagate to downstream distribution networks.
Intermittent power output, combined with a reduction in
system strength will result in a higher volatility in the
system voltage at transmission level making fast voltage
variations a possible issue.

Proliferation of converter-interfaced technologies such as
photovoltaic systems at the low and medium voltage level
is commonly taking place as single-phase connections.
Single-phase PV connections can be altered between
the phases but in places where only single-phase laterals
are available, all connections end up on the same phase
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low voltage level. These will have an increased level
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unbalance and hence their capacities may be limited
depending on the fault level at the point of connection.
Large scale wind and solar farms at transmission level
are often connected at remote locations supplied by
relatively long un-transposed lines, and hence voltage
unbalance can arise due to the lines despite the wind or
the solar farms injecting balanced currents.

5. Concluding Remarks

The power quality in the future power system is expected
to be significantly affected by the shift towards a carbon-
free electrical energy system. Several trends point to
degraded power quality indices of future power systems
due to the integration of many power electronics devices,
use of power cables at all voltage levels, increasing
amount of fluctuating production and generally reduced
system strength. However, with the ability to control
power electronics new possibilities are emerging and
if used correct many of the challenges introduced can
be mitigated by the same components that create them.
Doing so successfully requires high focus on power
quality studies both at individual connection and system
wide level, focus on grid code requirements and their
implementation and robust system monitoring with a
strategic approach.

It is generally expected that power systems around the
world will experience an increase in harmonic distortion
as the green transition progresses. This is partly due to
the sheer number of converter-interfaced equipment
being connected and partly due to possible modification
of existing distortion levels. However, emphasis on
limitation of harmonic emissions is gaining more
attention and driving a trend in the opposite direction, that
harmonic emission of new plant, as a whole, is reduced
at equipment level due to more advanced switching and
control technologies being implemented and the stricter
enforcement of grid code requirements.

Larger and more frequent voltage variations can be
expected due to increasing penetration of converter-
interfaced intermittent generation resources such as
wind and solar, and response of associated control
systems. Such voltage variations can lead to both under
voltage and over voltage where both situations can
have an impact on network operation and on customer
equipment. Reduced system strength at transmission
level means that voltage dips, typically caused by system
faults, transformer energization or large motor starting,
can become more frequent and severe and they will
also propagate to downstream distribution networks.
Intermittent power output, combined with a reduction in
system strength will result in a higher volatility in the
system voltage at transmission level making fast voltage
variations a possible issue.

Proliferation of converter-interfaced technologies such as
photovoltaic systems at the low and medium voltage level
is commonly taking place as single-phase connections.
Single-phase PV connections can be altered between
the phases but in places where only single-phase laterals
are available, all connections end up on the same phase
which can lead to significant voltage unbalance levels
on three-phase low voltage systems. Other converter-
interfaced technologies that will have an impact include
electric vehicle charging points and heat pumps at the
low voltage level. These will have an increased level
power capacity and are likely to introduce more voltage
unbalance and hence their capacities may be limited
depending on the fault level at the point of connection.
Large scale wind and solar farms at transmission level
are often connected at remote locations supplied by
relatively long un-transposed lines, and hence voltage
unbalance can arise due to the lines despite the wind or
the solar farms injecting balanced currents.

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The Need for Enhanced Power System Modelling Techniques and Simulation Tools

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1. Introduction
The transition to a clean energy future requires thorough understanding of increasingly complex interactions between conventional generation, network equipment, variable renewable generation technologies (centralised and distributed), and demand response. Secure and reliable operation under such complex interactions requires the use of more advanced power system modelling and simulation tools and techniques. Conventional tools and techniques are reaching their limits to support such paradigm shifts.

This paper provides an overview of commonly used and emerging power system simulation tools and techniques. Applications of these tools ranging from real-time power system operation to long-term planning are also discussed. Various approaches to gain confidence in the accuracy and applicability of the simulation models are presented. The paper then discusses emerging trends in simulation tools and techniques primarily stemming from the transition to a power system with increased penetration of inverter-based resources as these are used in variable renewable energy technologies.

2. Types of power system simulation models
This section provides a high-level introduction to power system modelling and study types for power system planning, operation and analysis.

2.1. Static models (phasor or sequence models)

2.1.1. Power flow
The power flow model is a steady-state snapshot of the network, with connected plant represented by simple and static power input/output and/or voltage characteristics. It may be likened to a single-line diagram that specifies the circuit layout and quantifies all network elements.

The power flow model of plants includes active-reactive power capabilities and static representation of network control equipment (such as transformer tap changers and reactive power support plant) that responds automatically to the steady-state conditions in the network by automatically adjusting their response.

The positive-sequence model is generally adequate to represent the steady-state behaviour of the power system in normal operation with predominantly balanced loads. The full three-phase model accounting for sequence components is required when the effect of network asymmetries is to be studied.

The model is used to perform AC power flow studies which calculates voltages and currents as well as active and reactive power flows at all nodes and branches in the model. These studies are typically performed for a range of scenarios, and their outcome is assessed against the planning or operational standards, such as the N-1 criterion, for thermal loading and voltage limits.

2.1.2. Fault level
Fault level studies are quasi-steady-state type analyses, where models supplied for these studies are required to represent the plant contribution to short-circuit current when a network element is in a faulted state.

Static models based on a Thévenin or Norton equivalent circuit, represented by a voltage or current behind an impedance, have traditionally been used for calculating the short-circuit current contribution of synchronous machines and this approach remains valid for such technologies. The sequence of actions taken by the fault ride-through control of inverter-based resources results in a different response at different instances during the fault and after fault clearance. Additionally, state-of-the-art control of inverter-

1 - The term inverter-based resources account for all inverter-based power system equipment including inverter-connected generators (centralised and distributed), high voltage direct current (HVDC) links and flexible alternating current transmission (FACTS) controllers.

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based resources allows for separate control of positive and negative sequence components of the fault current. Design variations exist that cover intentional negative-sequence injection to full cancellation.

For the inverter-based resources, the positive- or even the complete sequence representation might therefore be inadequate. The short-circuit response of such elements is sometimes studied using full dynamic simulations, or by linear approximation of the terminal voltage-current relationships for each phase sequence to obtain Thévenin or Norton equivalent circuit models. The IEC60909:2016 [1] standard provides formulae for Thévenin and Norton equivalent source components for different types of inverter-based resources in cases where an approximate linear short-circuit model is required.

2.1.3. Harmonic distortion

Harmonic analysis tools are based on quasi-steady-state frequency domain simulation methods, in essence an extension of the power flow solution with a superposition of multiple harmonic penetration solutions accounting for the fundamental and other harmonic frequency components, respectively. For this reason, it is sometimes referred to as a ‘harmonic power flow’, although at harmonic frequencies no full iterative power flow is performed (it is essentially a “pseudo” harmonic power flow). Quantities of interest include harmonic voltages and currents, loading and losses at harmonic frequencies, harmonic distortion and total harmonic distortion (i.e. over all frequencies).

Traditional electricity industry practice was to represent harmonic-generating devices as ideal current sources where the injected current source does not change with system impedance or due to the presence of other harmonic sources. However, this simple representation is no longer adequate in modelling modern converters. These are now modelled as a Thévenin or Norton equivalent circuit representation, including its harmonic impedance but it is known that this also has its limitations. To overcome limitations dedicated harmonic models can be utilised to reflect dependency of observed voltage and current harmonics on both the operating-point and on the grid background harmonics. Another method of analysis widely used in harmonic studies is the frequency scan that provides the impedance of the system over the analysed frequency range. This analysis is used to identify harmonic resonances under the assumption of linearity, which is a simplification in the case of power electronic converters [2].

Electromagnetic transient (EMT) models may be occasionally used to obtain more accurate representation of the harmonic performance of inverter-based resources or other nonlinear components in the time domain, however, such models are generally more complex and less widely used in industry for the estimation of distortion levels. Note that such an application is not considered a static modelling approach.

2.2. Dynamic models

2.2.1. Root mean square (RMS)

An RMS model is a time-domain model and provides a representative behaviour of power system elements in a simplified dynamic manner. Dynamic modelling of power system plant for time-domain simulation is made possible by exploiting the mathematical equivalence between the steady-state AC phasor representation of three-phase quantities, and the instantaneous representation of these quantities. Voltage and current variables are represented by complex numbers in what is referred to as the ‘phasor domain’. The RMS models can represent the positive-sequence only or include full three-phase representation.

Time-domain studies are used extensively to assess detailed dynamic performance of the power system, concerning rotor-angle, frequency, and voltage stability, in response to disturbances and set-point changes. Historically, RMS models have usually sufficed for assessing most power system technical performance issues of classical power systems, from a planning and operations perspective. However, an RMS model for dynamic simulation is inherently limited by the fact that the network itself retains its quasi-steady-state phasor representation. It is therefore only capable of representing the fundamental-frequency behaviour of network quantities, and excludes the dynamics associated with network elements themselves (also known as ‘network transients’). These limitations are usually immaterial for conventional stability studies where critical power system responses occur on timescales longer than an AC cycle. However, very short-term, sub-transient phenomena in either the network or connected
These studies are conducted with EMT models due to the dominant frequency of the phenomenon of interest being substantially different to the network fundamental frequency. The level of modelling detail required is therefore higher than that required for conventional dynamic studies.

Note that the harmonic resonance studies mentioned above differ from harmonic emission studies outlined in Section 2.1.3. When using EMT models and performing EMT studies, the level of steady-state harmonic distortion is not the main point of interest. Of primary interest is the potential de-stabilisation of the operation of plant, network components, or excitation of a system resonant frequency (for example during transformer energization with possible temporary overvoltages (TOVs)). This aspect of harmonic analysis is sometimes referred to as ‘harmonic susceptibility’. Such an analysis cannot generally be dealt with adequately using conventional harmonic simulation tools and requires advanced analysis techniques such as time-domain based EMT simulation models and methods.

An EMT model provides a full time-domain representation of a power system based on a level of detail that can accurately represent the kHz range switching frequency of semiconducting devices and fast control systems in inverter-based resources. For this reason, EMT models are being increasingly used in some countries for large-scale stability studies for operating scenarios with a high penetration of inverter-based resources, despite the dominant frequency of interest sometimes being in the same range as that of the network fundamental frequency. This will be further discussed in Section 3.

EMT models can be divided into offline and real-time models. Offline EMT models are being progressively used by network owners and system operators for large-scale power system studies and are generally available from most major Original Equipment Manufacturers (OEMs). For example, Australian Energy Market Operator (AEMO) has recently completed full-scale EMT models of the five South Eastern regions it operates [3]. From this experience it is understood that depending on the size of the network and number of dynamic models, 1 second of simulation may take between 1 and 10 minutes of actual simulation run time. This suggests that large scale state-of-the-art EMT modelling may be

2.2.2. Electromagnetic Transient (EMT)

Unlike in an RMS model, an EMT network model is represented as individual phase voltages and currents in the time domain linked by differential equations. Because of this, the EMT model can represent both the detail of sub-cycle controls, and the phase-by-phase response to unbalanced disturbances. This makes EMT models more accurate than RMS models, however, at the cost of higher computational burden, modelling complexity and input data availability. This is due to the inclusion of a greater level of detail and the need to perform the simulation with smaller numerical integration time steps, often in the order of a few microseconds, as opposed to a few milliseconds commonly applied to RMS simulation studies.

The following is a range of studies and phenomena for which EMT models have been traditionally used:

- Switching and lightning transients with a dominant frequency of a few hundred Hz to a few MHz. Examples of such studies include:
  - Insulation coordination
  - Black-start studies
  - Switching of network elements
  - Transformer energisation accounting for transformer magnetisation characteristic and inrush current
- Temporary and transient overvoltages caused by phenomena such as faults, harmonic resonances and ferroresonance, ranging from several tens of Hz to several kHz.
- Sub-synchronous oscillations covering adverse interactions between two or more electrical or electromechanical power system components with a dominant frequency below the nominal power system frequency but significantly higher than the range associated with local and inter-area oscillation modes.
- Detailed design studies for HVDC links and FACTS controllers, and interaction of several electrically close such devices.
more suitable for longer term analyses, ranging from weeks to years ahead studies, than conducting large number of contingency analyses within dispatch intervals of 5 to 30 minutes. The use of real-time EMT modelling addresses concerns regarding the speed of simulation for offline EMT studies. However, it is understood that the required software/hardware are not supported by many OEMs. This partly stems from the relatively higher cost of the required hardware compared to purely software-based methods.

In future it is expected that both the offline and real-time EMT tools will proceed with addressing the identified limitations. For example, Section 7 discusses several emerging trends that are being developed to increase the speed of simulation for offline EMT analysis.

### 2.2.3. Hybrid dynamic simulation

The use of hybrid dynamic simulation combining the advantages of each of the RMS and EMT simulations has been recently implemented in some commercial power system analysis tools. These include hybrid RMS and offline EMT, or RMS and real-time EMT simulation. Such an approach aims at representing region(s) of interest in EMT simulation and the wider power system in RMS with the two simulations running in parallel.

This approach provides the opportunity to use existing and encrypted RMS models for some of the legacy plant where possibly no information is available on their transfer function block diagram representation or associated parameters. Such a method assists in increasing the overall simulation speed compared to pure EMT simulation if the numerical integration time step of each of the inverter-based resources is relatively high, e.g. several tens of microseconds. However, in wide-area power system models comprising several models (requiring time steps of 1-2 µs) this approach may not provide a significant gain in time-efficiency.

A variation of hybrid simulation is the use of dynamic phasors along with RMS or EMT models. RMS models rely on phasor-domain representation of network and generator elements. This is often suitable for analysing low-frequency phenomena, e.g. below 3 Hz. However, above this frequency range conventional assumptions pertaining to phasor-domain representation become invalid. Dynamic phasors have been developed to address this shortcoming of the conventional static phasor-domain models. Availability of such models from OEMs of inverter-based resources is considered the key impediment to widespread use of these models for large-scale studies under scenarios with a high-share of inverter-based resources.

### 2.2.4. Linearised small-signal

Studies using linearised models are performed in the complex domain (frequency or impedance), often to assess the small-signal stability of the system and the adequacy of damping of oscillatory modes. The linearised models can also be used for identifying erroneous dynamic modelling, analysing forced oscillations, designing power system stabilisers (PSS) and power oscillation damper (POD) for increased damping of local and wide-area modes, optimal placement of monitoring and control of wide-area oscillatory modes, and as screening methods for studying subsynchronous resonances and torsional modes.

The approach is to use the dynamic models of connected plant and linearise these models around the specified operating point, to form a full state-space model of the power system. In other words, linearised small-signal models originate from the time-domain dynamic models and require a time-domain version for their derivation. Hence, the quality of resultant linearised models is directly dependent on the quality of the dynamic models and data. These linearised models are only valid for small-signal variations of the operating point.

The linearised models can provide the damping and frequency of all modes of the system, and information on parameters which can improve dynamic performance of the power system.

Key contributors to damping of small-signal oscillations are the of synchronous generators, and the of dynamic reactive power support plant. Detailed modelling of synchronous generators including the alternator, and excitation system and governor controls, is essential in the time-domain to derive the linearised small-signal model.

Inverter-based generators can also contribute to lightly damped or undamped small-signal oscillations. However, modelling such plant for small-signal stability assessment concerning damping of local and inter-area
modes of oscillations is not commonly adopted. These devices are inherently non-linear and time-varying. For small-signal stability investigations the inverter control system must be linearised first. A challenge in developing linearised models of inverter-based generators is the fact that the large-signal transfer function block diagram associated with the RMS dynamic models may not be readily disclosed by the OEMs unlike that has been applied to conventional synchronous machines.

Frequency-domain analysis tools indicating the damping and frequency of various oscillatory modes of the system have also been successfully applied to inverter-based generation. However, commercially available small-signal stability analysis tools may not include the detailed treatment of such devices. Furthermore, it is not currently a common practice for OEMs to supply such models in addition to their RMS and EMT models. Besides frequency-domain analysis methods, the use of impedance-based methods has recently emerged primarily as a screening tool to determine the need for more detailed analysis.

3. Modelling high share of inverter-based resources

3.1. New and emerging power system phenomena

Several areas of the world are beginning to anticipate or experience issues associated with a high penetration of inverter-based resources. Key contributing factors include lack of online synchronous generators, large electrical distances between areas of concentration of inverter-based resources and large synchronous generators as well as the increasing share of inverter-based resources compared to the local demand. Depending on the extent of interconnection, these issues could be characterised as either system strength or inertia challenges.

Phenomena associated with lack of inertia have been the focus of islanded power systems with a high penetration of inverter-based generation. Examples include the All Island (Ireland and Northern Ireland) and Tasmania power systems. According to the Irish study on high wind penetration levels [4], the integrity of frequency response and dynamic stability of the power system are compromised at high instantaneous penetrations of wind power generation. Several changes are needed to achieve high penetration levels, such as increasing the set-point of rate-of-change-of-frequency (ROCOF) relays and the introduction of new system services such as Fast Frequency Response (FFR) [4].

For interconnected power systems, lack of system strength is often the limiting factor as opposed to lack of inertia [4]. Simplified metrics for quantifying low system strength conditions are presented in [5] and [6] as well as technical issues that can be expected in such networks, including:

- **Voltage instability** – Weak grids experience a high sensitivity of voltage to changes in power and are prone to collapse.
- **Control interactions** – Fast voltage control loops can interact with weak networks and other nearby devices that have fast voltage control loops.

As system strength decreases, control loops of inverter-based resources could become unstable. They can therefore experience control instabilities even without any other inverter-based resources nearby. The impact of phase-locked loop (PLL) parameters on the small-signal behaviour of voltage source converters is discussed in [7]. To operate under low system strength conditions, the gain of the PLL may need to be reduced. In some circumstances stable operation may not be feasible without significant control modifications. Furthermore, operation of multiple inverter-based resources in close proximity could give rise to adverse control interactions and instabilities, often manifesting themselves as sustained sub-synchronous oscillations.

3.2. The impact of different control loops in inverter-based resources

EMT modelling may be required when studying the impact of inverter-based resources under low system strength conditions, where the local AC voltage amplitudes and phase displacements have a higher sensitivity to small changes in power flows associated with dynamic plant. For example, inverter-based resources often rely on a fast-acting to maintain synchronism between their injected currents and local network voltage and studying the stability of this PLL response often requires EMT simulations, as RMS models are inherently unable to represent such key components. The response of a typical all pass filter PLL
to a network phase angle jump and an unbalanced fault as obtained in RMS and EMT tools is shown in Figure 1 demonstrating the deficiencies of the PLL model in the RMS tool. RMS representation of other control loops such as DC link current and voltage controllers can exhibit similar inaccuracies. Without representation of such components, RMS models of inverter-based resources may fail to show a possible control instability and hence, in such cases could yield results that would likely lead to inaccurate conclusions being drawn. As the results of these types of dynamic studies feed into operational decisions, this could increase the risk of the power system being operated insecurely.

Figure 2 illustrates the frequency range of different power system phenomena ranging from a few Hz to several kHz often associated with pulse width modulation (PWM) in voltage source converters [8].

EMT models are replacing RMS models for large-scale power system studies in circumstances where the RMS models fail to predict the phenomena of interest. This often occurs when the phenomenon of interest has a dominant frequency deviating by more than ± 5 Hz with respect to the network fundamental frequency, or when the system strength available to inverter-based resources approaches close to or drops below the withstand capability of individual inverter-based units, e.g. a wind turbine or solar inverter. The latter application will apply even if the dominant frequency of interest is at or near the fundamental frequency.

Such an approach allows for accurate and adequate methods to manage the impact of new, modified or existing generation and other power system plant on power system security and network transfer capability.

To gain the maximum accuracy, EMT models should have a complete representation of all fast, inner controls as implemented in the real equipment. It is possible to create models which embed (and encrypt) the actual hardware code into an EMT component providing a direct one-to-one representation of the actual plant control codes without any potentially erroneous assumptions or manual implementation errors.
3.3. A practical example of emerging phenomena

Figure 3 compares the response of a large-scale power system with RMS and full EMT models subject to a credible fault in an area of the network with a relatively high penetration of inverter-based resources and far from synchronous machines. This figure demonstrates the ability of the EMT simulation to model the presence of sustained post-fault voltage oscillations with a peak magnitude of approximately 3% and a frequency of around 8 Hz aligning with those observed in a practical incident. These oscillations cannot be seen in the RMS simulation, because the dominant frequency of oscillations is far from the system fundamental frequency. Furthermore, an excessive post-fault over-voltage not seen in the EMT model response or actual response of the plant is present in the RMS model response. Figure 3 highlights a deficiency in RMS models in assessing power system security and quality of supply for a practical albeit low system strength network.

4. Modelling tools for planning and operational studies

4.1. Long-term planning

The timeframe of interest for long-term planning studies ranges typically from five years to several decades. The objective of these studies is to assess the adequacy of the transmission grid for future scenarios and to evaluate alternative expansion plans. These studies are usually carried out with power flow and fault level analysis only, although RMS dynamic analyses are sometimes used to investigate long-term dynamic issues (for example the need for dynamic reactive support) and/or to compare the robustness of alternative expansion plans.

More complex analyses are also performed on a case by case basis, depending on the characteristics of the network and the planned reinforcements. For example, a network expansion plan comprising series compensation of transmission lines will normally require sub-synchronous resonance (SSR) and sub-synchronous controller interaction (SSCI) studies using detailed EMT models. Similarly, for long-term expansion plans involving a large amount of HV/EHV cables, detailed EMT studies of TOVs and harmonic resonances are maybe needed to provide a feel on the likely issues to be encountered.

As of recently, transmission network owners and independent system operators are increasingly conducting dynamic studies to have a better basis on which to make decisions considering fundamental differences between synchronous generators and inverter-based technologies. The main areas of concern are a reduction in system inertia and system strength, with associated risks to power system security. As an example, this concern is addressed in European Union by legislation that sets requirements on Transmission System Operators (TSOs) to coordinate the dynamic stability assessments and to conduct a common study per synchronous area to assess the need for a minimum level of inertia in the region [9]. In addition, various EU funded research projects, led by TSOs, are looking into long-term scenarios with up to 100% penetration of inverter-based generation, e.g. MIGRATE [10] and EU-SysFlex [11].

Considering the potential for rapid technological changes in the timeframe of interest and uncertainty regarding the precise location, type and make of the generation to be connected, the use of site-specific, vendor-specific dynamic models is not relevant. Generic models in
the form of RMS dynamic models are therefore the most practical approach. However, increased uptake of inverter-based resources and reference to some of the new and emerging phenomena discussed in Section 3, would likely mean an increasing need for either enhanced RMS models or generic EMT models for long-term planning studies, depending on the phenomena of interest.

4.2. Connection studies

A suite of power system studies is generally conducted to firstly assess the impact of the new connection on the transmission or distribution network, and secondly to check its compliance with technical performance requirements. These studies cover steady-state and dynamic voltage and reactive power control, fault current contribution, harmonic emission and susceptibility, contribution to the damping of small-signal oscillations, response to voltage and frequency disturbances, active power and frequency control, transformer energisation and protection system requirements. In addition, controller interaction studies are increasingly becoming a requirement for connection of inverter-based resources in parts of the network with low levels of available system strength. To cover such a wide range of performance aspects, these studies often involve most (if not all) types of static and dynamic models discussed in Section 2.

One or more of the following types of models are considered mandatory in different parts of the world and different stages of generator connection studies.

- Detailed vendor-specific EMT models
- Reduced-order vendor-specific EMT models
- Reduced-order vendor-specific RMS models
- Generic RMS models

Initial system impact studies may use RMS models, but these have inherent limitations when increased uptake of inverter-based resources or a reduction in the dispatch of synchronous generators is considered. This particularly applies to studies of regions with a high penetration of inverter-based resources and, in such cases, detailed EMT models capturing the relevant control loops are required.

An emerging type of study being conducted in such weak regions is one which attempts to determine whether an adverse impact could occur on the system strength available to the wider power system and other connected network users as a result of connecting a new or modified inverter-based resource. These studies are increasingly performed with detailed, vendor- and site-specific EMT models of the generator under consideration and other nearby resources.

For example, a combination of these issues in the Australian National Electricity Market (NEM) resulted in the development of "System Strength Impact Assessment Guidelines" [12]. The typical sparsity of the locations to which inverter-based generators are connected and proximity to other inverter-based generators have meant that an increasingly large number of proposed connections need to undergo full assessment with detailed EMT simulations before their connection agreements can be finalised. This has been a necessary shift from the conventional approach of using RMS models for determining and agreeing upon the performance of proposed inverter-based generator connections.

4.3. Operational planning

Traditionally, network outage planning has been based on power flow and fault level analysis with occasional dynamic simulations considering critical transmission circuit outages near large generation plants to assess prospective stability issues and to define operational constraints. As power systems are increasingly being operated closer to their stability limits, dynamic assessments are becoming part of standard operational planning process in many countries. As an example, TSOs in the European Union are now required by legislation (EU 2017/1485) [9] to conduct a dynamic stability assessment at least once a year to identify the stability limits and possible stability problems in their transmission systems. These stability studies are normally performed using RMS models.

Small-signal stability studies are also performed with different regularity depending on the topology of the power system under consideration and the level of exposure to small-signal stability issues. This analysis is becoming more common as the displacement of conventional synchronous generators by inverter-based generation can either reduce damping of the inter-area modes of oscillations or introduce new oscillatory modes.
Constraint equations have been in place in power systems based on energy markets to manage the system security following contingencies without investment in assets that may be only occasionally required. To gain confidence in the accuracy of these constraints, a large number of RMS simulations are performed due to their relatively low computational expense.

The significant uptake of inverter-based generation, coupled with connection to weak and radial parts of the network, is making outage management and constraint development more complex as some of the phenomena of interest can only be accurately studied using EMT simulation tools. The time required to run a sufficient number of EMT simulations to confidently derive constraint equations could be well in excess of the total time that would have otherwise been spent to develop the same with RMS models. In addition, it is occasionally the case that particular network conditions, including specific outages, could result in substantially different responses compared to all other conditions.

Performing a large number of detailed dynamic analyses accounting for a range of contingencies, including those beyond the traditional N-1 contingencies, is becoming more important for system operators.

The paradox between the use of accurate and sometimes slow EMT models versus fast but sometimes irrelevant or misleading RMS models, highlights the need for improvements in current state-of-the-art dynamic models. These improvements will be discussed in Section 7 and constitute an important driver for further use of these models and tools for planning and operating power systems with a high-penetration of inverter-based resources.

### 4.4. Real-time operations

The situational awareness and decision support tools available in control rooms for real-time power system operation vary widely depending on the characteristics of the power system itself.

Most control rooms have Energy Management Systems (EMS) with real-time contingency analysis based on AC power flow to assess steady-state thermal loading and voltage levels.

Voltage stability studies, based on steady-state models, is an important part of the contingency analysis to assess the risk that voltage support equipment reaches its limits, which may lead to voltage instability.

In addition, real-time fault level calculations are performed in some countries using all three sequence models. These fault level calculations are performed to identify locations where prospective short-circuit currents approach (or exceed) the rated capabilities of plant equipment. In addition, fault level calculations help identify operating conditions or areas where system strength, as measured by the short-circuit ratio (SCR), drops below the minimum level beneath which the stability of control systems used in inverter-based generators cannot be maintained.

Although less common, some countries with a high share of inverter-based generation perform on-line dynamic stability assessments based on RMS positive-sequence models (e.g. Great Britain and Ireland). These analyses provide real-time information of potential instabilities and enable operators to maximise utilisation of available inverter-based generators in a secure manner. Since dynamic simulations are computationally intensive, their integration in real-time environments requires high-performance servers.

To date, EMT analysis are not integrated in any control room environment for real-time assessments. These simulations are usually significantly more computationally expensive than RMS models. Simulating several hundred contingencies on a large-scale power system within a typical dispatch interval of 5 or 30 minutes may not be achievable with current computing power. Several emerging trends to bridge this gap are discussed in Section 7.

Increased use of phasor measurement units (PMUs) in many power systems worldwide allows for improved monitoring and understanding system dynamic responses in a control room environment. This could include determination of conventional and emerging forms of system stability and associated screening matrices such as real-time calculation of system strength and inertia. However, better integration into dynamic security assessment tools, common standards and higher resilience against malicious data inputs are needed to fully utilise additional information and insights gained through PMUs.
5. Model validation

5.1. Objectives and principles

Gaining confidence in the accuracy of power system models is paramount as these are heavily relied upon for the development and operation of the actual power system. Model validation provides a measure of how accurate a given model is for the intended purpose(s).

A precise definition and understanding of the applicability and limitations of the models is critical to form an understanding of uncertainties and potential risks involved. For example, each dynamic power system model must be tested to the extent necessary to reasonably establish that it will meet the accuracy requirements. To achieve this:

- during the plant design and development stages, it is expected that the model will be rigorously derived from design information and its performance confirmed against the actual plant response; and
- following plant commissioning, the model response is confirmed by comparison against measured responses from staged tests.

IEC TR 61400-21 [13] outlines three validation classes for wind generation depending on the confidence and maturity level of the design and project implementation. The model validation requirements increase progressively as the individual plant or generating system that is based on them advances through the commissioning process and actual operation. While this standard has been specifically developed for wind generation, the overarching principles and classes of validation may be applied to other inverter-based generators. The three classes presented in this standard include:

- Class 1: Simulation models or calculations based on design information and assumptions. The use of software in the loop (SIL) methods incorporating actual design characteristics with the integration of actual control codes of the inverter-based generator is preferred.
- Class 2: Hardware-in-the-loop (HIL) validation (see Section 5.2.1 for further details)
- Class 3: Validation using field measurements obtained from staged testing either at an individual generating unit, e.g. wind turbine, or the entire generating system, e.g. wind farm (see Section 5.2 for further details).

5.2. Plant level validation by staged tests

5.2.1. Unit level, e.g. a wind turbine, HVDC link or FACTS controller

Hardware-in-the-loop (HIL) simulation

An approach adopted by power system equipment manufacturers is HIL testing to simulate disturbances well before plant undergoes on-site commissioning and model validation. This approach is increasingly used by manufacturers to develop and test new control systems as well as their associated models. Furthermore, some TSOs (e.g. RTE in France) have adopted real-time simulation (RTS) and HIL as standard practice (using replicas of the actual controllers) to validate models and test different operating conditions in the system with particular focus on HVDC and FACTS controllers [14].

These RTS units are often connected to replicas of the controllers. These replicas are provided by respective vendors together with the real controller, e.g. HVDC converter. This comes at an extra cost and the need for an update every time the equivalent controller is updated. While this approach is well established for HVDC links and FACTS controllers and commonly used by the OEMs of inverter-based generators [15] and [16], it is not currently widely used by TSOs/Independent System Operators (ISOs) for simulating the response of inverter-based generators as it requires a software model to represent the replica. Further developments are likely to occur in this area and are discussed in more details in Section 7.

Actual unit testing

Various methods of conducting field tests on actual integral assembly of a generating unit such as a wind turbine or solar inverter has been adopted by different OEMs. These tests are often in addition to the HIL testing discussed above. A common example of such an approach is the so-called container tests used in some European countries for certifying the simulation models of the inverter-based generators. It follows a well-known, relatively simple and well-established test procedure. However, it does not provide full flexibility for controlling voltage and frequency, and has not been very widely used for assessing performance under low
Figure 4 Comparison of measured and simulated response of a synchronous generator during staged commissioning tests in response to a +5% voltage set-point step response test: (a) terminal voltage, (b) active power, (c) reactive power
system strength conditions, i.e. when the individual plant’s SCR approaches unity. Furthermore, the duration of these tests can be prolonged due to unavailability of energy source, e.g. insufficient wind.

**5.2.2. System level, e.g. a complete wind or solar farm**

During commissioning, validation of model performance can be demonstrated by model overlays based on tests, and by continuous monitoring described below. Most system operators have specific requirements and procedures for testing and model verification which must be complete before the plant is allowed commercial operation in the market. For example, in the Australian NEM, the accuracy of simulated response as compared with the measured response ought to comply with prescribed model accuracy requirements set out in AEMO’s Power System Model Guidelines [17].

As an example, Figure 4 compares measured and simulated responses of a synchronous generator when subjected to a +5% voltage set-point step response test: (a) terminal voltage, (b) active power, (c) reactive power compares measured and simulated responses of a synchronous generator when subjected to a +5% voltage set-point step response test. The +/-10% accuracy bands required in the Australian NEM are superimposed onto the measured and simulated responses to better illustrate

Figure 4 Comparison of measured and simulated active and reactive power response of a synchronous generator subject to a network fault

Figure 5 Comparison of measured and simulated active and reactive power response of a synchronous generator subject to a network fault
the accuracy achieved. Note that due to the background active power oscillations a quantitative assessment of the conformance against the prescribed model accuracy requirements has not been attempted for the active power.

Staged fault ride-through testing of the complete generating system has been occasionally conducted \[18\]. It provides an accurate, controlled and deterministic way of assessing the compliance of generating system, in particular under low system strength conditions, and validating respective simulation models while minimising uncertainties associated with fault parameters. The level of preparation and potential modifications required in the network configuration and protection system settings, and the possibility of wider network implications including load disruptions have led to infrequent application of this method.

5.3. Benchmarking against major system disturbances

Congruence between plant and model dynamic responses for some aspects may be difficult to demonstrate until a network disturbance occurs. The use of a continuous monitoring program is often prudent to demonstrate model accuracy for all major items comprising the plant (i.e. both at a generating system and generating unit level). High speed data collected during a disturbance can be overlaid to demonstrate correct model responses. Any significant differences observed in recorded performance can drive an investigation into compliance with grid code requirements as well as the need to re-test specific features of the plant to re-tune the original models or to develop and validate new models. As an alternative to costly plant testing, numerical curve fitting techniques can be used to re-tune and optimise model parameters to match the recorded plant responses. This approach requires a high level of expertise and understanding of the models and should be used with caution as it can lead to inaccurate responses for system disturbances other than the one used for the parameter optimisation. Best results are obtained when data from multiple recorded disturbances is applied to the validation process.

Figure 5 compares measured and simulated active and reactive power responses of a synchronous generator subject to a network fault compared measured and simulated active and reactive power responses of a synchronous generator when the wider power system was subjected to a network fault. The +/-10% accuracy bands, as required in the Australian NEM, were also superimposed onto the same graph to provide an indication of the accuracy level achieved. Measured responses were collected through high-speed monitoring systems installed at the generator’s connection point and several other points in the network. A large-scale power system model was used for this analysis and the fault impedance was adjusted to result in the same voltage dip as experienced in practice.

Furthermore, it should be noted that from a small signal perspective, it is particularly valuable to be able to assess the small signal stability using measurements during normal operation. The small changes constantly occurring in the system result in noise (or ambient data), which may be analysed to approximate the damping and frequency of the known natural modes of the system. Staged tests or the use of actual system disturbances can be used to validate the behaviour of specific load types also. Validation of load models has recently gained more attention worldwide with several ongoing activities and this is discussed further in the next section.

6. Challenges in distributed energy resources (DER) and load modelling

In the past, utility-scale plant constituted the majority of generation with only a small contribution coming from DER. When DER levels were low, the behaviour of DER had relatively little impact on power system stability and could be managed within the range of normal uncertainty in the modelling process.

The worldwide uptake of residential distributed photovoltaic (PV), battery storage and adoption of electric vehicles (EV) is expected to continue at scale in coming years. As DER levels grow, the behaviour of DER becomes increasingly significant, and it is no longer appropriate to operate the power system with only detailed understanding of large-scale generation and the wider transmission and distribution network.

Utility-scale generation can be actively optimised, and there is a detailed understanding, regulation and real-time visibility of its capabilities and operational
distribution systems have been considered as passive which from a system perspective could be seen as single load points.

Difficulties in characterising the DER response to system disturbances and developing a sufficiently accurate aggregate model (as seen by the upstream transmission network along with the presence of numerous makes and settings), have meant that state-of-the-art dynamic models of the DER do not have the same level of maturity and accuracy compared to generator dynamic models. Several efforts are in progress worldwide [19], [20] to continuously improve the understanding of the DER response and to improve currently available RMS models for the DER. These models are considered appropriate when system strength is sufficiently high and DER penetration is not significant in the power system. Figure 6 shows a commonly used model aimed to represent the aggregated dynamic behaviour of the DER and load in RMS stability studies. This model represents the combined (aggregated) dynamic behaviour of many tens to hundreds of small distributed inverter-based generators on the distribution system, for example for commercial, industrial or residential distributed photovoltaic generation. The same applies to the load model. However, in this case four different types of motor loads, an electronic load and a static are provided to distinguish salient differences between key load types. Some or all these components can be used as necessary. The DER and load model interface with the wider distribution network model via aggregate impedances as shown in the figure.

Predictability is also required in much shorter timescales in order to adequately manage system stability. Hence, the behaviour of DER must now be factored into tasks such as:

- Setting line flow limits to manage oscillatory, transient, and voltage stability;
- Determining minimum synchronous unit requirements for maintaining system strength and inertia; and
- Conducting connection studies to confirm required performance standards for new or modified generating systems.

The control systems in inverter-based DER may have settings that cause a large capacity to act in unison, and the possibility of mass mis-operation of large numbers of devices during power system disturbances poses a serious risk to system security. In some disturbances, DER behaviour may be a critical factor that determines overall system outcomes.

The location of DER further complicates power system studies, since from a transmission perspective the distribution systems are not fully modelled. Historically,

Power system planners and operators require adequate models and tools to effectively forecast upcoming system conditions, to simulate likely system performance under future conditions and have confidence in how the system will perform. Adequate levels of predictability and visibility of all system resources are essential for secure power system operation.

Figure 6 Most common composite load and DER model

behaviour. That is not often the case for DER at present, and in particular for kW-range DER.

Difficulties in characterising the DER response to system disturbances and developing a sufficiently accurate aggregate model (as seen by the upstream transmission network along with the presence of numerous makes and settings), have meant that state-of-the-art dynamic models of the DER do not have the same level of maturity and accuracy compared to generator dynamic models. Several efforts are in progress worldwide [19], [20] to continuously improve the understanding of the DER response and to improve currently available RMS models for the DER. These models are considered appropriate when system strength is sufficiently high and DER penetration is not significant in the power system.
A reduction in the system strength due to the retirement or decommitment of synchronous generators, and increased uptake of inverter-based resources both at the large-scale and DER level would mean that the veracity of RMS models cannot be ensured under certain circumstances initiating the need for developing EMT models of the DER. A further difficulty in developing EMT models of DER is the fact that the concept of vendor-specific control systems and corresponding models does not largely apply.

Increased numbers of active components in the distribution system, and interactions with the transmission network is not limited to DER only. There has been an increasing trend in deploying inverter-based loads in the distribution system as well as the inverter-based DER, both of which share somewhat similar characteristics and pose similar challenges to power system planning and operation. The need for adequate load models is therefore equally important. Load modelling is highly complex due to the vast number of load devices in a power system, making it unfeasible to model (a) each device separately; and (b) each possible loading scenario. Thus, some level of aggregation of loads will always be needed as pertains to DER modelling mentioned above. Furthermore, the development of new types of loads is resulting in the changing response of loads. With the trend towards increasing utilisation of inverter-based loads, the load dependency on voltage and frequency is decreasing. Not only this should be reflected in the load model itself, but also when modelling the frequency response of the power system and the amount of load relief assumed.

7. Emerging trends

7.1. High performance computing

Developing EMT models for large-scale power systems comprising several hundreds to thousands of busbars has not been widely attempted by system operators. This is partly due to the computational burden of running large numbers of EMT models in parallel.

To address simulation speed issues associated with EMT models, state-of-the-art solution techniques are being progressively developed by software and hardware developers, in collaboration with system operators and network owners. Concurrently, improvements are being applied to the speed and robustness of the simulation models developed by OEMs. The ability to conduct EMT simulation studies for large-scale power systems could become a necessity in the next few years as several jurisdictions implement ambitious renewable energy targets.

Increasing complexity in power system responses and interactions from the transmission network level all the way down to the consumer level, also prompts the need to process and analyse a higher quality and quantity of the electrical and non-electrical data to ensure that the power system can be securely and reliably planned and operated while transitioning to the future power system.

The need to process and analyse a higher quality and quantity of the data and perform simulation studies with more detailed models in a sufficiently short timeframe, emphasises the significance of high-performance computing. Several hardware and software-based methods, or a combination of the two have been developed and implemented in practice. For example, the use of cloud computing and platforms allow for vast improvements in processing speed and storage, enabling real-time data analytics. The following would assist to achieve this:

• Integration and augmentation of applications (as well as the relevant models), e.g., parallel processing using cloud computing.
• Parallelising applications and models to run in the cloud allowing for a) dramatically faster run-time for individual model runs, and b) modelling of thousands of scenarios in parallel (instead of sequentially) requiring a fraction of the human labour and engineering judgement.

7.2. Machine learning and artificial intelligence

Algorithms coupled with artificial intelligence and machine learning are being increasingly applied in complex environments to enhance decision making for system operators, weather forecast organisations and generation owners/operators among key organisations directly or indirectly involved in various aspects of power system planning and operation. While such tools often allow making a more educated decision, caution should be exercised when selecting this kind of tool as such machine learning algorithms might be designed to prioritise economic outcomes over secure and reliable power system operation.
Accounting for such actions in power system planning and operation is therefore becoming important. However, it is noted that these kinds of behaviours do not often follow classic control theories. Developing mathematical models for this behaviour and integration in power system simulation is therefore challenging.

### 7.3. Probabilistic modelling

Decision making for future planning and operation of the power system involves a higher level of uncertainty due to increased uptake of variable and intermittent large-scale inverter-based resources, the inherent uncertainty associated with the aggregate response of the loads and DER, and the increasing use of complex algorithms by both the generators and consumers. In such a power system, a fully deterministic analysis may not be always possible due to lack of input data, large parameter variation, or may prove impractical due to the need to evaluate a large number of deterministic scenarios.

A probabilistic analysis makes use of probabilistic input data or analysis methods such as probabilistic power flow or optimal power flow. Such a method becomes important as soon as input parameters are known to be random or if the intention is to simulate a range of ‘what-if’ scenarios in the future to assess sensitivities to forecast errors and determine the optimal scenario from a cost-benefit perspective.

### 8. Concluding remarks

The transition to a clean energy future will require the use of more advanced and detailed power system models and simulation tools. This is critical such that the power system can be planned and operated securely and reliably. EMT modelling will be required when studying the impact of inverter-based resources under low system strength conditions where RMS modelling may be unable to reliably predict control instability. Control interaction studies are increasingly becoming a requirement for connection of inverter-based resources in parts of the network with low levels of available system strength.

The ability to conduct EMT simulation studies for large-scale power systems is becoming a necessity in some jurisdictions who are implementing ambitious renewable energy targets. To date, EMT analysis has not been integrated in any control room environment for real-time assessments. These types of simulations are usually significantly more computationally expensive than RMS models. To address simulation speed issues associated with EMT models, state-of-the-art solution techniques are being progressively developed by software and hardware developers as discussed in Emerging Trends Section.

As DER levels grow, their behaviour becomes increasingly significant. The control systems in inverter-based DER may have settings that cause large numbers to act in unison, and the possibility of the mass mis-operation of large numbers of devices during power system disturbances poses a serious risk to system security.

There has been an increasing trend in deploying inverter-based loads in the distribution system as well as the inverter-based DER, both of which share somewhat similar characteristics and pose similar challenges to power system planning and operation. The development of adequate load models is therefore expected to become equally important.

Fundamental to all types of power system modelling approaches and plant models is model validation. Gaining confidence in the accuracy of power system models is paramount as these models are heavily relied upon for the development and operation of the actual power system. Model validation provides a measure of how accurate a given model is for the intended purpose(s). Commonly used model validation practices adopted worldwide by different entities ranging from OEMs to system operators were presented in Section 5.

### 9. References

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Summary
The Finnish Transmission System Operator, Fingrid Oyj, has launched an Internet-of-Things (IoT) project, which is a part of a strategic digital substation project. The goal of the IoT project is to provide better visibility to the functional performance of substation assets. With this knowledge, it is possible to detect emerging defects and allocate maintenance resources to the assets where the need is verified by using the data-oriented approach. From asset management perspective asset reliability will be secured, cost-effectiveness improved and outage requests optimized. The aim is to increase utilization of IoT technology in the future in order to enable condition-based asset management on a large scale.

A functioning IoT-platform for asset management requires, among other things, sensors for specific measurements, a cloud platform for analytics and data management, a robust data transfer between the sensor endpoint and the cloud platform and an efficient end-user tool for data visualization and alarms. At the time of writing, there are not completely ready and cost-effective solutions available in the market for all these areas, fulfilling the requirements of large-scale utilization of IoT technology. Therefore, each area requires in-house development as well as co-operation with partners.

This paper presents IoT-sensor technology already taken in use at substation level and the status and goals of development projects on different IoT-sensor technologies for monitoring of specific asset groups and phenomena. Moreover, the developed cloud-computing platform including analytics, data and metadata management are presented. In addition, insights on current development of the end user tool and user interface, the so-called Asset Performance Management (APM) application, are presented.

1. Introduction
Large-scale implementation of sensor solutions for substation assets is nowadays possible, due to affordable sensor technology and wireless data transfer solutions. Compared to traditional time-based measurements and maintenance, continuous online measurement solutions provide more frequent and more precise information on asset condition in different environmental circumstances. New technology reveals changing trends in asset condition and pinpoints assets with outlying performance, indicating the need for maintenance or replacement.

A large number of IoT sensors generate a vast amount of data on the operational characteristics of different asset types and asset models. On top of the state-of-the-art sensor technology, a modern cloud computing platform is needed to handle provisioning, communication and software management of IoT devices as well as processing, storage and analyses of measurement data. Finally, the outcome based on performance value indicators, need to be presented to end users in form of time series graphs and deviation notifications. Mobile applications are needed to ensure efficient usability of the data.

Use cases of IoT can vary from a simple one-point temperature measurement to multi-scale neural network computing analytics for acoustic emission for example. Therefore an IoT system has to be flexible and capable

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Internet of Things - Asset management - Substation - Switchgear - Condition monitoring - Asset Performance Management
of including different approaches. In some cases, it is sufficient that the measurement data is received from a third-party service. In other cases, it may be necessary to hold the whole data management process strictly in one’s own hands to ensure that correct analyses are applied.

Furthermore, the high voltage environment may impose restrictions on what type of sensors or communication technology can be used. In these circumstances, sensor applications require very specialized analysis algorithms. The possibility to implement customized functionalities on a vendor’s platform may be limited and lead to clashes over the ownership of the data and the intellectual property. In fact, the challenge in large-scale utilization of IoT is that in many cases vendors aim to provide their own complete end-to-end solutions, which may lead to an unnecessary collection of separate systems with overlapping functionalities. Thus, achieving a good end user experience being cohesive and engaging, may turn out to be difficult and costly.

In essence, Fingrid’s answer to the challenge is to split the IoT project into several development paths and build it bottom-to-top from domain perspective. The core for the system consists of cost-effective wireless sensor solutions developed together with several partners in the field of modern technology. The reliability-centered approach is used to identify the assets and their specific functionalities that are to be monitored with IoT measurements. Fast and easy installation and commissioning of sensors is important as well as the possibility of retrofitting to existing substation equipment.

2. Sensor development

The first generation of Fingrid’s switchgear monitoring system was presented at Cigre Session 2018 [1]. It is now being replaced by the second generation, providing new monitoring functionalities, better Edge-computing capabilities and remote management of the sensor units. The partner for sensor unit development was selected in an R&D-competition in summer 2018. At the time of writing, these 2nd gen monitoring systems have been installed at 2 substations on 5 bays including 50 IoT units and roughly 300 sensors. The system will be extended during summer 2019 to another 15 bays corresponding to 900 sensors. The goal is to move towards large-scale installations in the upcoming years. The main functionalities of the system are acoustic monitoring of gears, motors, dampers etc. and traditional current profile analysis of coils, motors and CT secondary circuits. A set of performance value indicators are calculated from the measurement data in the cloud platform.

Control building IoT monitoring has been commissioned at ten substations so far. The monitoring system includes environmental sensor capable of measuring temperature, humidity, air pressure and water leakages. The sensor has also been modified to withstand a high voltage environment. Wireless temperature monitoring of disconnector contacts, current paths and current transformers are being implemented for 10 bays as for the proof of concept stage. Figure 1 shows a few examples of sensor installations on primary parts of a current transformer, a circuit breaker and a disconnector.

The sensor concept includes also acceleration sensors and is being utilized for busbar vibration monitoring.

In addition to sensor-based temperature measurements, an IoT solution based on a wireless thermograph camera has been developed to support temperature deviation analysis in specific use cases. The thermograph camera monitors a broad area while the temperature sensor measures the temperature at a single point.

The thermograph camera is capable of monitoring all the three phases of a current transformer, for example. As for the sensors, three units are required to cover all the three phases. On the other hand, the resolution of the camera is low which occasionally results in inaccurate measurements. An example of a temperature matrix provided by the thermographic camera is shown in Figure 2.
customer from the responsibility to manage platform updates. The subscription of the cloud platform and the data is owned by Fingrid. The architecture of the platform is designed to be lightweight, to store data efficiently, and to enable data processing by third parties.

Figure 3 shows Fingrid’s IoT concept from the sensor endpoint to the end user endpoint. The data recorded by different sensors, for example audio files, is sent from substations to the cloud platform. The files are uploaded to storages and analysed by specific algorithms. For example, audio files are decoded and run through multiple algorithms processing the signal, for example applying Fourier transform. The outcome of processing is stored in a SQL database as plain time series data and as specific performance indication values that describe the raw data, such as current profiles and audio signals. Data in the SQL database is taken further into data visualization tools for the end users.

A use case on acoustic emission monitoring for post insulators is under development and the first deviation analysis of defected units have been accomplished in a laboratory environment.

Radio Frequency Interference measurements have proven to be a powerful tool for detection of dielectric defects for example in current transformers, cable terminals and bushings. An innovation challenge in order to implement an IoT solution will be launched in 2019.

In addition to the ongoing sensor development projects there is a large amount of different use cases for modern online monitoring where IoT solutions can be utilized.

3. Cloud platform

Fingrid's IoT cloud platform is built on the commercial Microsoft Azure cloud service. It utilizes serverless, Platform as a Service components which frees the

![Figure 2: A picture and a low-resolution temperature matrix of a current transformer. Overheating of the first unit in front is visible in the temperature matrix.](image)

![Figure 3: Principle elements of data processing in the switchgear monitoring use case.](image)
sensors is large. Thus, Fingrid has developed a prototype of a mobile application for metadata management. The mobile application can view and modify the metadata of an IoT device, including the related assets, sensor types and measurement types. This makes commissioning and replacement of devices more efficient.

In the longer perspective, the goal is to run advanced algorithms already in the substation level by utilizing Edge-computing approach. Currently, all the algorithms providing performance value indicators are run in the Databricks analytics engine. This requires that all the raw data is transferred from a substation into the cloud platform. In certain use cases, such as acoustic emission measurements, the amount of transferred data is large and thus large storage resources are needed. An Edge-solution would be beneficial for continuous real-time monitoring use cases and applications with high sampling frequencies such as RFI. The amount of data transfer between substations and the cloud would decrease significantly.

Management of software updates and configurations in the IoT devices and gateways is a continuous requirement. A solution for comprehensive remote management is to use Docker containers, into which the updated algorithms are packed. By using Azure IoT Edge service functionality, it is possible to filter and select multiple IoT devices to which different versions of containers are uploaded with little effort.

4. Asset performance management tool

Fingrid has been using different online condition monitoring solutions for years, such as SF6 density monitoring of circuit breakers and GIS, and transformer...
The requirements for an APM application are presented in the following list. The requirements are presented more thoroughly in the Master's Thesis made for Fingrid [2].

The main requirements for an APM application are:
- Efficient time series data management
- Versatile capability to implement different types of charts and graphs
- Effortless navigation between assets and dashboards
- Asset fleet analysis tools
- Alarms configurable to detect deviations in the measurement data
- Notifications to end users when alarms are triggered
- Summary tools such as health index

Considering time series data visualization, the basic requirements are cursors and support for showing multiple trends in a single view. On the other hand, versatile types of charts and graphs are needed for the event data to show all the useful information that can be mined out of the data. Figure 5 is an example of a dashboard for switchgear. It shows time series data and trends of event data, and a navigation panel enables easy navigation between assets.

One of the key functionalities of an APM application is asset fleet analysis, in other words comparing performance values between assets of an equal model or type. This functionality enables pinpointing anomalies and possible defects at early stages. An example of an asset fleet analysis dashboard is shown in Figure 6.

Finally, alarms triggered by limits or more complex analytics are needed to pinpoint deviations in the data.

Figure 5: A sketch of an APM dashboard visualizing condition data of a circuit breaker [2].
Alarms can be indicated to the end users by email or SMS notifications.

Fingrid will also implement health indices in the upcoming APM application in the future. A health index combines all the condition data of an asset into a simple numerical value. This helps the end users to have a quick overview of asset condition and to compare the condition among an asset group. Health index analytics has been discussed for many years and there are various possibilities to implement a solution. However, the main challenge has been the lack of reasonable source data. IoT technology will improve the situation remarkably as the amount of available data will increase dramatically.

5. Conclusions
Using Internet-of-Things technology for modern asset condition monitoring is a way to move towards real, large-scale condition-based asset management. The main obstacle delaying this transition has been the lack of condition data and it seems to have been overcome nowadays.

New technology provides visibility to asset performance in substations. The possibility to detect deviations is becoming cost-effectively available in large-scale. This enables asset managers to predict the development of defects prior to major breakdowns and failures which secures the grid reliability. Furthermore, cost-effectiveness of asset management can be improved by allocating maintenance resources to the assets where deviations have been detected. The transmission system availability increases when outages for time-based inspections and maintenance are minimized.

From utilization perspective, large-scale benefits require large-scale installations. This is possible only if the system is very cost-effective from end-to-end. Remarkable effort needs to be put in each step of development. While the transition towards Internet-of-Things based online monitoring is a major technological innovation project, it is even more a change management project. In a conservative environment, such as the energy sector, a successful leap to a new era of condition monitoring requires willingness to improve and change, and courage to question old and established methods. Major effort is needed also to study new possibilities, to acquire new innovative partnerships and to apply agile working methods. In addition, a great amount of testing, piloting and data validation are involved until breakthroughs take place. Finally, they will take place and reform the field of asset management.

6. Bibliography
Unwanted blocking of differential protection during converter transformer internal faults

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Summary
High-Voltage Direct Current (HVDC) technology transports bulk electrical power over long distances efficiently and economically, and also allows the interconnection of asynchronous power grids. In a HVDC converter station, a converter transformer provides the appropriate voltage for converter commutation and also ensures galvanic isolation between the AC system and the DC link. The provision of adequate protection for a converter transformer is crucial; it must limit the damage to the transformer and adjacent plant when an internal short-circuit fault occurs.

Differential protection is widely applied to converter transformers, owing to its simple operating principle, high sensitivity on internal faults, and excellent security on external faults. Nevertheless, a challenge is to prevent mal-operation during transformer energization (i.e. magnetizing inrush). Numerous techniques have been used to discriminate between inrush conditions and internal faults, but harmonic blocking is the simplest and the most widely used solution. Harmonic blocking assumes the second harmonic component dominates the inrush current, but is an insignificant component of the internal fault current. However, this approach is less effective in modern transformers that use cores made by low-loss amorphous materials; these materials produce lower harmonics in the inrush currents. The challenges are even more complex for a converter transformer, which operates in a complicated environment affected by AC and DC stresses. This suggests significant second and fifth harmonic components can occur in the internal fault current, and the fault current may behave like an inrush current. As a result, a harmonic blocking element may wrongly inhibit the operation of the differential protection, and the converter transformer may be subjected to fault currents for an extended period, leading to severe damage or even the rupture of the transformer tank.

Differential protection must detect all possible short-circuit faults within a converter transformer, but few studies have considered how harmonic blocking performs when an internal fault occurs in a converter transformer. This paper investigates whether harmonic blocking is suitable for identifying inrush conditions in a converter transformer. To achieve this, the CIGRE HVDC benchmark test system available in PSCAD/EMTDC is utilized, and an appropriate differential protection scheme is designed for the converter transformers. Asymmetrical internal faults are simulated to assess the operating behaviour of the differential protection with harmonic blocking. The test results demonstrate the differential protection is unable to initiate a trip signal when an internal phase to ground fault is applied on the DC side of a converter transformer. The fault analysis implies the fault current contains a heavy DC component which flows towards the fault point via the windings of the converter transformer. This heavy DC component induces a DC bias flux, which leads to significant converter transformer half-cycle saturation, and results in an increase in the second harmonic in the differential current. As a result, the ratio of second harmonic to fundamental in the differential current is beyond the pre-set blocking threshold, restraining the differential protection. The results analysed in this paper demonstrate a harmonic blocking inrush identification approach may adversely block the operation of the

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HVDC, converter transformer, differential protection, half-cycle saturation, harmonic blocking
differential protection during an internal fault on a converter transformer.

1. Introduction

High-Voltage Direct Current (HVDC) is an effective technique for delivering bulk electrical power over long distances and for interconnecting asynchronous grids. In a HVDC system, a converter transformer isolates the AC grid from the DC link, and provides the appropriate commutation voltages required by the valves. To limit the damage to a converter transformer during short circuits, differential protection is usually employed as the main protection scheme owing to its simple operating principle, high sensitivity on internal faults, and good security against mal-operation on external faults and non-fault events [1].

Nevertheless, conventional differential protection encounters a critical challenge, i.e. distinguishing between magnetizing inrush and internal faults. Numerous methods have been proposed to prevent differential protection mal-operation in the event of transformer energization, and the most widely applied approach is harmonic blocking. This approach assumes the second harmonic component dominates an inrush current but is significantly lower in a fault current. Although the effectiveness of harmonic blocking has been confirmed in many applications, this approach has a limitation; it can be difficult to determine an appropriate blocking threshold which can be guaranteed to not affect the operating performance during an internal fault. This is because the second harmonic component seen in the internal fault current, may in some cases be as high as that observed in an inrush current, and as a result, the operation of differential protection would be desensitized or delayed [2],[3].

Time-delayed fault clearance is unacceptable for converter transformers, but few studies have considered the operating behaviour of harmonic blocking during converter transformer internal faults. Paper [4] considered the harmonics produced by converters might lead to the harmonic blocking element misjudging the current caused by an internal fault to be an inrush current, which means the operation of the differential relay would be wrongly blocked. Paper [5] suggested, in the case of converter transformer internal faults, the negative sequence components in the AC system could introduce second harmonics into the thyristor valves due to the interaction between the AC and DC systems, causing unnecessary blocking of differential protection. More tests, however, need to be conducted to further verify these points. Paper [6] analysed the failure of differential protection operation during converter transformer internal faults. It was demonstrated that the waveform of the differential current was high in the first halfcycle of the fault current, but small in the next half-cycle; this characteristic was similar to an inrush current and consequently, the additional harmonics caused the differential protection to be wrongly blocked. However, the explanation about this result was based on the wave-shape characteristics of the differential current, and the reason for this unusual characteristic and the increase in harmonics remain uncertain.

This paper thoroughly investigates the reasons differential protection may fail to trip during a converter transformer internal fault. To achieve this, the CIGRE HVDC benchmark test system was simulated, and an appropriate differential protection was applied to the converter transformers. Multiple types of internal faults were used to assess the dependability of differential protection with harmonic blocking. Fault analysis demonstrates an internal asymmetrical fault on the DC side of the converter transformer results in a heavy DC component that dominates the fault current and flows to the fault point through the windings of the converter transformer. This causes the converter transformer to experience significant half-cycle saturation, which results in the generation of excessive second harmonic components. Eventually, the ratio of second harmonic to fundamental in the differential current goes beyond the blocking threshold, and this wrongly activates the harmonic blocking.

2. Operating behaviour of differential protection with harmonic blocking during converter transformer internal faults

2.1. Modelling

To thoroughly demonstrate the operating behaviour of
differential protection with harmonic blocking during converter transformer internal faults, the CIGRE HVDC benchmark test system available in PSCAD/EMTDC was utilised, see Fig. 1. This is a standard reference model for the study of an HVDC system in terms of control strategy and recovery performance. This system is a monopolar HVDC link designed to operate at 500 kV and 1000 MW. The AC/DC converters are represented by two six-pulse thyristor-based valves in series connection (i.e. forming 12-pulse converters) and are installed at both the rectifier and inverter sides. In each converter station, two converter transformers with winding connections of grounded Y-Δ (T1) and grounded Y-Y (T2) operate in parallel and provide a 30° phase shift to achieve the 12-pulse rectification. More information about the primary system can be found in [7] and [8].

In this paper, the protection of the converter transformer T1 installed on the rectifier side is primarily studied. The default parameters of T1 in this benchmark system are 603.73 MVA and 345/213.4557 kV. The positive sequence leakage reactance and copper loss are 0.18 p.u. and 0.02 p.u. respectively, and the air-gap reactance is 0.2 p.u.; the knee point is 1.25 p.u. and the magnetizing current is 1%. The protection currents are measured from the CTs installed on both sides of the converter transformer T1. To simplify the investigation, the protection CTs are over-dimensioned, i.e. they do not saturate during transient conditions. Therefore, the turns ratio of the CTs on the AC and DC sides are 1500/5 and 2000/5 respectively, and each is connected to a burden resistance of 0.05 Ω.

2.2. Transient study

In this study, the converter transformer T1 was implemented with conventional percentage differential protection with harmonic blocking. The differential current and the bias current were derived using the following equations:

\[ I_{diff} = |I_1 - I_2| \]

(1)

\[ I_{Bias} = \frac{|I_1| + |I_2|}{2} \]

(2)

where \( I_1 \) and \( I_2 \) are the phase currents obtained from the protection CTs at the AC and DC sides of T1 respectively. The operating characteristics of the protection were set in accordance with conventional criteria, i.e. the tripping threshold was 0.3 p.u., the breakpoint was 2 p.u., the lower slope 1 was 30%, and the high slope 2 was 60%.

According to the surveys conducted by CIGRE WG C2/B4.28 [9], the majority of transformer failures were related to connections and terminals, because these components are usually subjected to the superimposed AC and DC stresses. In this regard, different types of fault, single-phase to ground, phase-to-phase to ground, and three-phase faults were applied on the terminal at the DC side of T1 respectively, and each fault lasted for 0.5 seconds. The following subsections describe selected results, where the differential protection failed to operate on an internal fault.

2.3. Scenario 1: Single-phase to ground fault

Initially, a single-phase to ground (A-G) fault occurred on the DC side T1 terminal at \( t = 1.005 \) s. The response of differential protection is demonstrated in Fig. 2. In this figure, \( \text{Diff} \) denotes the waveform of differential current; \( \text{Fund} \) denotes the magnitude of the fundamental component of differential current; and \( 2^{nd} \text{Ratio} \) denotes the ratio of second harmonic to fundamental components in the differential current. The grey shaded region shows when the harmonic blocking element was activated.

As illustrated by the \( A_{Diff} \) in Fig. 2, the asymmetrical A-G fault leads to an increase in differential current, and the corresponding magnitude (\( A_{Fund} \)) is beyond the operating threshold. In the meantime, the content of the second harmonic in the A-phase differential current increases, and the harmonic blocking element is activated for a very short time (less than 10 ms). This is caused by the sudden transient onset of the fault which produces second harmonics in the differential current, and this will occur for all faults [10]. The \( A_{2^{nd} \text{Ratio}} \) in Fig. 2 demonstrates a brief gap between the shaded areas, suggesting the harmonic blocking element is deactivated for 2 ms. In practice, the differential protection is unable to operate during this...
differential relay should initiate a trip signal. However, the second harmonic ratios, \( A-2^{nd} \text{ Ratio} \) and \( B-2^{nd} \text{ Ratio} \), in the A and B phase differential currents are greater than 15% for the entire duration of the fault occurrence. Consequently, the differential protection is incorrectly blocked, and this fault cannot be cleared in a reasonable time.

3. Fault analysis

The previous two examples demonstrate incorrect blocking of differential protection during converter transformer internal faults. However, to determine exactly why the protection failed to operate, Scenario 1 is now thoroughly analysed.

As illustrated in the \( A-\text{Diff} \) in Fig. 2, the waveform of differential current sharply increases after the fault initiation and then decreases demonstrating spikes. This wave shape characteristic suggests the converter
of the valve group G1 are grounded, as shown in Fig. 5. After the fault occurs, the DC currents on the transmission line significantly decrease; the control system at the rectifier side then provides fast response to this current reduction and reduces the firing angle from the nominal level ($\alpha = 17^\circ$) to the minimum limit ($\alpha = 5^\circ$) to maintain the current level, as shown in Fig. 6. This suggests the firing pulse is persistently initiated to trigger the thyristors, i.e. the lower-arm thyristors of G1 and the thyristors of G2 are capable of conducting and commutating during the fault condition. Consequently, after the fault occurs, DC currents are converted by the valve group G2 and then delivered by the lower-arm thyristors of G1. Because of the potential difference between the fault point and the converter ground electrode, these DC currents then return to the ground electrode of G2 via the ground. As a result, a new loop for DC currents is formed, i.e. valve group G2 – lower-arm of G1 – windings of converter transformer

The A-G fault on the DC side of T1 can be treated as a short-circuit across the valves [6],[11], i.e. the anode of the upper-arm thyristors ($D_{11}$, $D_{31}$, and $D_{51}$) and the cathode of the lower-arm thyristors ($D_{21}$, $D_{41}$, and $D_{61}$) of the valve group G1 are grounded, as shown in Fig. 5. After the fault occurs, the DC currents on the transmission line significantly decreases; the control system at the rectifier side then provides fast response to this current reduction and reduces the firing angle from the nominal level ($\alpha = 17^\circ$) to the minimum limit ($\alpha = 5^\circ$) to maintain the current level, as shown in Fig. 6. This suggests the firing pulse is persistently initiated to trigger the thyristors, i.e. the lower-arm thyristors of G1 and the thyristors of G2 are capable of conducting and commutating during the fault condition. Consequently, after the fault occurs, DC currents are converted by the valve group G2 and then delivered by the lower-arm thyristors of G1. Because of the potential difference between the fault point and the converter ground electrode, these DC currents then return to the ground electrode of G2 via the ground. As a result, a new loop for DC currents is formed, i.e. valve group G2 – lower-arm of G1 – windings of converter transformer
in Fig. 5 (a)); the DC components in \( D61 \) and \( D21 \) flow through the “short” by passing through the a-b and c-a windings of the converter transformer T1 respectively (see the red and yellow arrows in Fig. 5 (b) and (c)); afterwards, these DC components are superimposed on the faulted phase currents and flow through the “short”. The DC components displayed in the lower plot of Fig. 4 confirms this phenomenon, i.e. they flow into the converter transformer T1 via the phase B and C terminals and out of T1 via the phase A terminal.

Hence, during the transient period, the lower-arm thyristors of G1 experience a “three-phase short-circuit”, and the fault currents deviate from the zero axis as they contain significant DC offsets [12],[13]. Based on the newly formed DC current loop, the fault currents flow through the “short”. Hence the DC component in \( D41 \) flows into the faulted phase directly (see the pink arrow
4. Conclusion

The operating behaviour of differential protection with harmonic blocking in the event of converter transformer internal faults was evaluated in this paper. A differential protection scheme was designed and implemented on the converter transformer used in the CIGRE HVDC benchmark test system. The investigation shows that differential protection is unnecessarily blocked when an internal asymmetrical fault occurs on the DC side of the converter transformer. Based on fault analysis, it was demonstrated the DC components dominate the fault current and they flow to the fault point via the windings of the converter transformer. As a result, the converter transformer is significantly saturated, due to the additional DC bias flux, and this produces second harmonics in the differential current. Consequently, the ratio of second harmonic to fundamental in the differential current is beyond the inhibiting threshold which leads to the incorrect blocking of the differential protection.

The primary reason differential protection fails to trip during converter transformer internal faults is half-cycle saturation of the transformer core. This saturation stems from the significant DC components in the asymmetrical fault current. As a result, high levels of the second harmonic component are measured by the differential protection and this causes the activation of a second harmonic blocking element. The likelihood of unnecessary blocking is higher when the cross-blocking function is activated. Consequently, a harmonic blocking based inrush identification method is not suitable for differential protection applied to converter transformers, i.e. it is unable to differentiate inrush conditions from internal faults.

5. Bibliography


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Planning for a sustainable transmission service and grid – an approach to maximise opportunities and minimise stranded assets

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Summary
Transpower is New Zealand’s bulk transmission Grid Owner and System Operator that operates, maintains, and develops the national grid, and runs the wholesale electricity market in real time. We, as with utilities around the world, recognise the uncertainty that is emerging in the world’s electricity ecosystems [1][2][3]. On one hand, electricity may play a major role in decarbonisation and on the other, highly distributed and intelligent energy resources have the potential to fundamentally change the role of transmission networks. Transpower published the Te Mauri Hiko – Energy Futures white paper to initiate discussion and early action to address New Zealand’s changing electricity needs [4]. Building upon the white paper, we are looking at adapting our business as usual processes to ensure we can understand and manage the risks and opportunities that may emerge as New Zealand responds to climate change.

Although there are utilities and similar industries that do use scenarios [2][5][6] to help navigate uncertainty, we have not been able to uncover the details of how they are used. This was part of our motivation to share our work with others, so we can share and learn from peers that are in a similar circumstance as ours. In this paper we share our approach split into four components (see Figure 8):

• Continuous monitoring for signs and signals that indicate the Country’s approach to addressing climate change issues and the uptake of new technologies.
• modelling these futures in relatively high detail and periodically updating the models with insights from monitoring and continuous improvement initiatives
• analysing information from the modelling work and providing insights on change in use of the transmission system
• using these transmission insights to guide our investment decision making process in order to maximise opportunities and minimise risk.

This paper will discuss each component’s function, their process and how we use their outputs to help manage the increased uncertainty due to our response to climate change and the uptake of new technologies.

1. Introduction to transpower
In the mid-1990s, the introduction of the wholesale electricity market saw the denationalisation of New Zealand’s electricity industry, and a transition away from centralised generation and transmission planning and operation. Transpower is the national Grid Owner and System Operator that operates, maintains, and develops the national grid, and runs the wholesale electricity market in real time. The segregation of the different entities owning, and operating transmission and generation assets means that Transpower is not involved in the decision-making process for the capacity, location, technology or timing of generation commissioning or decommissioning. Since the electricity market reforms, Transpower’s long-term transmission planning must not only meet the need of projected system load growth, but also accommodate generation connection and disconnection decisions as they are announced. This

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requires an agile and malleable approach to outside influences.

2. Te Mauri Hiko – Energy futures
We, along with our international peers, recognise the uncertainty that is emerging in the world’s electricity ecosystems [1][2][3]. On one hand, electricity may play a major role in decarbonisation to meet our Paris Agreement commitments. On the other, highly distributed and intelligent energy resources have the potential to fundamentally alter the role of transmission networks in the future. The pace of change and uncertainty also challenges our traditional planning timelines and decision-making tools.

In 2018, Transpower published the Te Mauri Hiko – Energy Futures white paper to initiate discussion and early action to address New Zealand’s changing electricity needs, recognising New Zealand will soon find itself amid a global energy transformation [4]. Building upon the white paper, we are looking at adapting our business-as-usual processes to ensure we can understand and manage the risks and opportunities that may emerge as New Zealand responds to climate change and the country’s uptake of new technologies.

3. New Zealand’s decarbonisation context
New Zealand’s greenhouse gas emissions primarily come from the agriculture and energy sectors (with the energy sector covering transport, manufacturing industries and construction, energy industries, other sectors and fugitive oil and natural gas) [7]. Figure 1 shows New Zealand’s emission profile in 2017 under six sectors with LULUCF as Land Use, Land-Use Change and Forestry, IPPU as Industrial Processes and Product Use, and Tokelau representing the emissions of Tokelau which is a dependent territory of New Zealand.

Within the energy sector, the largest source of emissions arises from road transportation contributing 14,457 kilotons carbon dioxide equivalent (kt CO2-e) which represents about 44% of the energy sector’s total emissions and 25% of our net emissions (56,895 kt CO2). Public electricity and process heat production contributed 3,596 kt CO2-e which represents about 11% of the Energy sector’s total emissions and about 6% of our net emissions.

Electricity generation contributes to such a small percentage of New Zealand’s net emissions.

Increasing renewable generation remains a key focus, but as New Zealand already has over 80% renewable generation, there is a growing focus on reducing emissions in the agriculture, transportation and industrial sectors.

In this respect, our position is somewhat unique compared to our international peers where electricity generation contributes a much more significant portion of their net emissions [8][9].

4. Managing uncertainty
Traditionally, Transpower used one set of demand forecast and a range of generation build (supply) scenarios produced by the New Zealand Ministry of Business, Innovation and Employment (MBIE) to determine and justify transmission investments. However, new technologies and their possible uptake can create a wide range of demand scenarios and broaden the supply scenarios 1. We recognised the need to develop a way to incorporate this wider uncertainty into

1 - We define a scenario as a future where the demand or supply follows a certain trajectory that represents a key trend being monitored. Whereas a combination of a demand scenario and supply scenario represents a future where we can attribute likelihood-of-occurrence to for the purposes of investment planning.
We understand that similar industries do use scenarios to help navigate uncertainty, but we have not been able to uncover the details of how they are used [2][5][6]. This was part of our motivation to share our work with others, so we can share and learn from peers that are in a similar circumstance as ours.

5. Monitoring

In Te Mauri Hiko we took a scenario-based approach to consider what the future may look like in the year 2050. This provides a mechanism to understand the opportunities and challenges in New Zealand’s energy future. As discussed in this paper it provides the foundation for our strategic and planning work – comparable to our understanding of the purpose of the scenario work undertaken by Shell for the last 50 years [10].

We started from the key trends shaping global energy – climate change, urbanisation, technology and geopolitics. Culminating (in our identification in 2018) of four possible future demand scenarios and five possible supply scenarios, as well as a base case (NZ Inc + Clean NZ), which we consider to be the most likely future combination of our possible demand and supply scenarios by 2050.

Like most utilities, we appreciate there will be significant geo-political and technological change, and an increasing pace of change, each of which increases future uncertainty [1][5][6]. It is likely there will be periods of relatively quick step-changes and significant disruption, as has been evident in other industries such as telecommunications, broadcasting, and transportation (with the change to internal combustion engines), so it is critical we monitor the signs and drivers that underpin our scenarios. This active intelligence gathering provides continual insights to help us identify possible and likely future scenarios.
In order to monitor the scenarios, we first addressed the uncertainties, then defined drivers and used these to identify signs that we can monitor. At the outset, our strategy work on Te Mauri Hiko leveraged the key megatrends to ascertain the biggest areas of uncertainty such as technology change, electrification of transport and more. We distilled these into the 9 key drivers that made the biggest impact on our scenarios which are shown in Figure 3.

These drivers span topics from the response to climate change (if this is more aggressive the consequent electricity demand is much more and vice versa), growth of distributed solar and storage (which affect the needs of transmission) and the electrification of transport and process heat (driving significant new energy demand).

The drivers are not directly measurable, so we use a mixture of quantitative and qualitative signs to illuminate them. Some of the leading indicators we monitor are global factors, and others are limited to New Zealand’s position, but all are specific to what we consider to be driving one or more of the future scenarios for energy in New Zealand.

A monitoring report is produced quarterly which serves three key purposes:

- Firstly, the report collates our insights on the key drivers shown in Figure 3 so we can estimate the likelihood of the scenarios we have established. It enables us to report on and signal the extent to which we remain on track with our base case future scenarios and which scenarios appear to be the most likely alternatives to the base case.
- Secondly, the monitoring enables us to check if our scenarios adequately represents the mega-trends and whether if there is a need for a new scenario to ensure we are adequately covering the key uncertainties expected.
- Thirdly, it enables continuing discussions within the business, with our Board, and most importantly with our stakeholders, customers and the wider industry in New Zealand. It enables us to compare our insight on what we consider to be the current key drivers of change in our evolving environment, how that compares to what others are monitoring or gaining insight on. It also enables greater collaboration to ensure we can plan for and meet the needs of our customers, and the electricity consumers of New Zealand, in the face of growing uncertainty.

Whilst the monitoring of these leading drivers does not decrease the uncertainty, it ensures we are regularly collating and analysing evidence to allow us the best chance to make prudent and commercial planning decisions to enable New Zealand to transition to a lower carbon future.

6. Modelling and forecasting

Our approach to demand forecasting relies on a combination of standard time series analysis (stage 1 forecast), overlaid with a scenario-based forecast of future factors (stage 2 forecast). The stage 1 forecast centres around historical data, while the stage 2 forecast allows us to speculate on factors that are not present in historical data. These speculative factors include:

- Electric vehicles
- Solar photovoltaic installations
- Battery uptake
- Industrial process heat electrification
- Demand side behaviour and/or network tariff changes

These factors are all associated with our national response to climate change and meeting established targets.

The Stage 1 forecast is a standard time series analysis combining three forecasting methods [11].

1. Long term endogenous model – linear regression of demand from 1997
2. Short term endogenous model – regression of demand (differenced to obtain stationarity) using an AR(2) auto-regressive model
3. Econometric model – regression of demand on GDP from 1997

All methods use temperature-corrected historical data. This means that any strong historic temperature anomaly that creates a significant peak (or trough) in demand does not strongly affect the future trend.
The different models have different strengths and weaknesses; the long term endogenous forecast is simple and transparent but can suffer from inaccuracy (particularly in the short term); the short term endogenous model places greater importance on more recent data, thereby improving short term accuracy; the econometric model correlates GDP and demand growth, a relationship that has decoupled slightly in recent years.

Ultimately our stage 1 forecast is a weighted average of these three methods. We generally choose equal weights although we occasionally give greater weight to the AR(2) model to help with short term accuracy. The output of the stage 1 forecast is a probability distribution of likely demand as a function of the year and geographical region. In Figure 4 we show this output at a national level.

Our stage 2 forecast considers different scenarios in which new technologies reach varying levels of penetration. The forecast relies on an underlying model which quantifies how different assumptions lead to different levels of demand. The key element in our approach is to let assumptions define parameters within the forecast. Parameterisation allows us to maintain a degree of flexibility in our forecasts and rapidly update the numbers as we test and compare different assumptions.

For electric vehicles (EVs) we focus on the EV market share of new entrant vehicles in New Zealand. We separate the problem into categories; Private Light EVs, Commercial Light EVs, Bus EVs, and Truck EVs. We use parameters of the Bass diffusion model [12], within each category, to define how the technology captures market share. This information, coupled with the historic vehicle survival and utilisation rates (provided by the Ministry of Transport, (MoT), gives us the total number of vehicle-kilometres-travelled (VKTs) within each category. The calculation is schematically laid out in Figure 5. To test extreme scenarios, we have made an aggressive assumption (3rd input in Figure 5) with regards to how rapidly EVs capture market share. This scenario may occur, for instance, in the case of EV subsidies being introduced into the market.
We use data collected by the Electricity Authority (regulatory body) on distributed (embedded) solar PV installations. This data includes, at a grid-exit-point (GXP) level, the number of new installations and the capacity of each installation. We then make assumptions around the final saturation level of the solar and connect the historic data to the (assumed) saturation level with a best-fit Bass diffusion curve. Examples are shown at a national level in Figure 6.

Our battery uptake curves primarily assume that the technology is linked to solar PV uptake. We assume a certain kWh of storage per solar installation and apply that figure nationwide. The current level of battery storage in New Zealand is too low to provide any genuine basis for future prediction. We assume a significant amount of industrial process heat is electrified. The Energy Efficiency and Conservation Authority (EECA – a government agency) end-use database on coal and gas consumption provides our primary data resource. The data is separated into 4 dimensions; industrial sectors (of which there are 30), geographical regions (the 16 political regions of NZ), end uses (of which there are 7), and different technologies (of which there are 9). We then make assumptions about efficiency and propensity to convert based on where the energy sits within this array (i.e. which industrial sector, which technology, which end use, etc.). Efficiency is assumed to vary according to end use and technology. We define a parameter called propensity to convert which allows us to treat special cases. For example, the petroleum manufacturing industry would not convert their gas use to electricity, or potentially a certain factory may be known to have gas boilers that are near retirement.

We treat consumer’s battery usage behaviour as a proxy for network tariff evolution. Batteries are here assumed to be used as a peak-flattening device. The consumer can choose to flatten peaks at either a national level, an island level, a regional level, or a GXP level. If a national level is chosen, the assumption is that energy and generation is principally setting the price of electricity. If a GXP level is chosen, the assumption is that the transmission network is principally setting the price.

The energy forecast from the stage 2 is converted to a peak demand forecast using assumed profiles relevant to different technology and consumer behaviour. For example, we define EV charging profiles that either contribute-to or avoid peaks.
Supply Side Modelling

Once we agree that a demand forecast is worthy of further consideration, we apply a series of supply side models to estimate the scale of generation expansion required and the different hydro/thermal scheduling behaviour. We use a cost minimisation approach with stochastic hydro inflow assumptions based on historical data. Circuit flows are estimated using DC load flow equations on hourly demand data (coming from the stage 2 demand forecast) going out to 2050.

Different supply side scenarios arise due to variable cost assumptions for different types of technology. For example, wind being more economic than solar may define one scenario or increasing the viability of a large new hydro project may define another scenario. Transmission constraints are not considered when modelling the generation expansion as the objective was to understand the transmission implications if the lowest cost generation was built to supply the demand.

7. Transmission insights

As a Grid Owner, the most valuable insight is how transmission system use may change over time and across futures. Understanding potential transmission use will allow us to pick where there are divergences (indicating risks) and convergences (indicating opportunities) in the range of futures we consider realistic. The transmission insights are designed to complement our enhancement and development investment planning (E&D) process [13] by providing a longer-term perspective across a range of futures. Our E&D process continues to utilise the existing process as a basis but draws on transmission insights to provide a guide on long term risks or opportunities. Figure 8 shows the process we are trialling and how it integrates with existing processes (with blue background).

The modelling work produces 3 major sets of data which are; demand, supply and flow-duration on transmission lines (calculated from DC load-flow data). By extracting transmission change-in-use information from the flow-duration data, we can broadly understand how the transmission system is projected to be used under different futures without having to conduct load-flow analysis separately which is very resource intensive.

System Planning involvement in developing inputs for the models will allow maximum use of the data produced from the models. It is important to make realistic assumptions on how generation and large loads are connected so we can get good transmission insights.

Insights need to be simple to understand and highlights the fundamentals important to the user. As the Grid Owner, understanding the fundamentals that underpin investments in transmission assets helps with designing metrics to provide the insights. In the New Zealand context, we take a largely economic approach to investment on transmission assets. The two most important factors that determine what we invest in are the peak and load profile expected on our assets. Peak is relatively easy to measure and understand but the load profile is not. We borrowed the ‘capacity factor’ metric from the wind generation industry where the wind farm’s average output divided by its rated output is used as a measure of the windfarm’s consistency in terms of electricity production. Similarly, to windfarms,
The different possible futures and their likelihood of materialising is a matter of judgement. Our existing investment decision-making processes consider a range of options to meet the need and we determine the net benefit of each option. The option which maximises net benefit becomes our preferred option [14]. We use sensitivity analysis to test the robustness of the preferred option but rely heavily on the economic testing to determine our preferred option.

While we can apply the same approach for each scenario in the future, the preferred option in each scenario may differ. It will be a matter of judgement as to which scenario and hence, which preferred option, is most likely.

This quandry means that:
- Deferral options (short term options that defers need for more significant expenditure, allowing the future to resolve more) have value
- Options which can be staged will have more value as they can be cancelled or changed if the future does not unfold as forecast

8. Investment planning and decision making

As illustrated in Figure 8, we want to consider a range of futures when making grid enhancement decisions (which is governed by our Asset Management Decision Framework). The futures introduce uncertainty into our plans, so we have considered techniques for managing the risks associated with these uncertainties.

The flow-duration information is used to calculate the two metrics, change-in-peak and load-factor (average load divided by peak load), which are normalised to the first year of the forecast (as a near representation of the present). Figure 9 shows the two metrics of a transmission corridor for a range of futures. From these metrics, we can identify whether the trajectories are converging or diverging which will ultimately influence our approach to investments.
• We should also identify least regrets options, i.e. options which minimise the regret, rather than options which maximise net benefit.

Deferral options include demand response, thermal uprating of transmission lines and the use of battery storage. Such options will normally meet the need for a few years and although they have a cost, they may allow the future to resolve sufficiently that more significant investments can be identified with a higher degree of certainty.

Staging options, although not always possible, has the same effect as deferral options and may mean more significant investments can be made with a higher degree of certainty.

Least regrets analysis involves identifying the option which minimises the regret of making a wrong decision should the future unfold differently from forecast. Figure 10 shows how the option which maximises net benefit (equivalent to minimising whole-of-life cost), can differ to that which is least regrets.

Summarising the issues described above and utilising the transmission insights, our investment decision-making process becomes:

• Where the preferred option is the same under all scenarios (i.e. scenarios paint the same picture) – proceed.

• Where the preferred option differs under various scenarios (i.e. scenarios paint different pictures) – use deferral options where possible, to allow as much uncertainty to resolve as possible.

• Where the preferred option differs under various scenarios (i.e scenarios paint different pictures) and deferral options are not available or have been used up – identify the least regrets option and use judgement to decide which option to proceed with.

Stage investment where possible.

These processes are emerging thoughts and are not necessarily aligned with our existing regulatory requirements. We have yet to discuss this approach with the regulator prior to implementing it.

9. Bibliography


Advanced techno-economic modelling of distribution network investment requirements

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Summary

In an increasingly dynamic and changing electricity sector with rising distributed energy resources, new network investment models are needed that enable consideration of flexibility, uncertainty and risk. Existing modelling frameworks include “top down” models that offer a comparison of investment and investment strategies between scenarios and “bottom up” models that consider detailed technical impacts on real networks. These frameworks are broadly appropriate for analysing investment, with the requirements of the business, stakeholders and regulator influencing the specific model design and implementation. There are a number of dimensions across network engineering, investment, customers and energy markets to be captured and represented in the modelling at some level. This paper presents a number of advanced modelling techniques which can be applied to both top-down and bottom-up modelling frameworks, enabling better consideration of customer variability, network risk and optioneering of solutions.

Drawing on Bayesian statistics, customer load has been represented using a sophisticated statistical model that reflects both variability and uncertainty in demand on LV networks. This can help to explicitly quantify network risk due to existing loads, new loads and customer flexibility. A network ‘emulator’ model provides significantly faster run-times for analysis of large solution sets by parameterising the variables of a power flow model against the inputs. This has been applied and tested with LV, HV and EHV networks with results closely matching equivalent power flow models. Implemented in combination with the Bayesian customer load model enables probabilistic, risk-based modelling. A constrained cost optimisation algorithm has also been developed to find the lowest cost combination of solutions that can address constraints that have arisen on a network. This is based on a cost function that accounts for factors including disruption costs, cross-network benefits, life expectancy, enabler costs, flexibility, as well as capex and opex.

Finally, it is important that these models represent the reality of the actual network planning and investment decision making processes they are representing. This is often very complex, and can be difficult to reflect in a model. Alternatively, decision-making processes may be adapted to incorporate them.

1. Introduction

Network investment modelling is a core element of business planning for distribution networks. Business planning is generally driven by regulatory price controls or similar with the business plan then delivered, monitored and updated over the price control period. This includes both load-related and non-load related investment (although in this paper, we only consider the modelling of load-related investment).

The modelling of load-related investment is typically broken down into the following elements at a high level:

- Definition of future load scenarios
- Characterisation of network performance and constraints under future load scenarios
- Modelling of interventions to be deployed for constrained networks, and then Modelling the corresponding investment requirements for those interventions, at scale across an entire distribution network area

Essentially, the modelling process aims to reflect the network planners decision-making processes for

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investment, but on a large-scale and coherently across the business. In practice, this decision-making process is often nuanced and complex and may rely on a planner’s experience of a specific network. This can be difficult to capture fully in a model. It is described in more detail below.

**Future Load Scenarios**

There is considerable uncertainty about the long-term evolution of the world’s energy systems. The interlinked trends of decarbonisation, decentralisation and digitisation are widely recognised, however, the exact manner in which these will impact the energy system is very unclear. For example, many people expect widespread adoption of electric vehicles to happen in the future, but the scale and the pace of this adoption is not clear. Furthermore, it is credible that other technologies (e.g. hydrogen fuel cell) cars could displace EVs in the future, which would have a much less significant impact on the networks.

Therefore, planners often define long-term scenarios for electricity supply and demand, that consider a range of credible future demand and generation. This enables a consistent and coordinated assessment of investment needs across both transmission and distribution. These include the uptake of low carbon technology (LCTs) such as electric vehicles and heat pumps, evolving network interventions and, increasingly, distributed flexibility trends such as energy storage and demand side response.

One of the emerging challenges is the modelling of new loads such as EVs and HPs where there is little available data to date on patterns of usage and how they interact with existing loads and between themselves. Various innovations projects, including Low Carbon London [1], Customer Led Network Revolution (CLNR) [2], My Electric Avenue [3] and the National Renewable Energy Laboratory [4] have looked at patterns of residential off-street parking. However, in total this amounts to less than 500 records for slow chargers, covering around a year each. It’s similar for public datasets that describe the behaviour of residential off-street fast chargers. Although this will change in future, particularly with the development of the internet of things and the roll-out of smart meters, business planning decisions may need to be taken before a substantial amount of data is available to inform modelling of these loads.

In addition, scenarios are typically defined at a country-wide level, or for large regions. But, for distribution networks, it is necessary to disaggregate these scenarios down to a much more granular level. Achieving this at a granular enough level for accurate LV modelling is challenging and any estimate of this is likely to be uncertain.

**Characterisation of Network Performance**

Transmission networks are, almost by definition, much smaller in scale in terms of the numbers of circuits and their extent. For example, the Great Britain (GB) transmission network includes approximately 24,000 km of overhead line and cable, with typical lengths of around 20km. In contrast, distribution networks typically comprise 10,000s if not 100,000s of substations. The GB distribution network includes ~800,000 km of overhead lines and cables. A significant proportion of this is low voltage (400 V) network, including, by one estimate, almost one million low voltage feeders, which tend to be less than a kilometre in length. This is split across fourteen distribution licence areas, with an average of around 57,000 km of circuit per licence area. Modelling the full extent of the distribution network in detail i.e. as a whole power system model, is clearly not practical.

Distribution network behaviour is thus, generally modelled at a greater level of detail at higher voltage levels (e.g. using power flow models) where network security is more critical and at a more conceptual or representative level for lower voltage networks where volumes are higher and criticality is lower on an individual network basis. Network characterisation at a minimum should enable the identification of constraints i.e. investment triggers (due to thermal loading, voltage and, in some cases, fault level and harmonics) the minimum capacity required from any network interventions, and allow for robust scaling up of investment requirements to licence area level.

For distribution networks, there are also challenges due to the lack of planning and operational data. Data at higher voltage levels tends to be of a reasonably high quality, comparable with similar data about the transmission network. However, at lower voltage levels, the quality and quantity of data tends to decline. This makes distribution network models more challenging to build and verify. This is a particularly profound problem as the cost impacts of heat and electrification are likely to be more significant for the LV network. Smart meters can help to fill in gaps where available, but there are open questions about how
such data can be used to inform LV network performance if incomplete or aggregated due to data privacy.

To date, characterisation of distribution network performance has generally been undertaken on the basis of the most stressful network conditions i.e. peak demand and peak generation at summer minimum, with consideration of network security requirements and validation against existing SCADA data. However, this approach may not be suitable for new loads and evolving customer behaviours on the network which may lead to greater diversity of constraining conditions and how these might be best managed, and may not help to understand year-round cost drivers such as losses.

There is also an inherent randomness in how a customer uses electricity, which is increasingly apparent at lower voltage levels, and there are even striking differences in the patterns of behaviour between customers that are demographically similar. This uncertainty also applies to intermittent renewable generation and flexibility solutions such as demand side response which rely on a customer behavioural response. Modelling of network performance in a more probabilistic way that accepts and characterises the uncertainty of both existing and more importantly, new loads, and interventions should enable an understanding of network risk. However, this is only considered in transmission network modelling at present [5] [6].

**Modelling of Interventions and Investment Requirements**

“Smart” and no-network interventions are increasingly being considered as network intervention options at a range of voltage levels, particularly where there is significant uncertainty around levels of future loading. Whilst these interventions generally provide less capacity than more traditional network asset solutions, they are less costly and faster to deploy and provide more optionality for future network planning and investment.

However, the capacity provided by, and cost of, flexibility solutions are both much more uncertain compared to traditional network assets. For example, they may rely on a customer behavioural response (even more automated responses rely on certain conditions to be present) or response of intermittent generation or energy storage. For strategic modelling purposes, it might be reasonable to assume that they can provide a certain “typical” level of capacity to the network. However, the estimation of any generalised capacity increase should be based on a more nuanced understanding of (over-) procurement levels required for various services and the likelihood of a certain level of response.

Optioneering of network interventions both at a strategic as well as business as usual level should consider the lifetime capital and operational cost of the solution, as well as the cost of any other “enabling” assets. It might also be necessary to consider harder to quantify costs, such as the cost of disruption or the optionality value of a solution [7]. It should also be noted that the drivers for network investment can be complex and far-reaching beyond purely load related drivers. For example, asset size can also be driven by losses and reliability. These should be considered when assessing the value in novel techno-economic modelling techniques.

### 2. Overview of existing modelling

Table 1 lists some of the dimensions that a techno-economic model of distribution network investment would be looking to capture at some level.

<table>
<thead>
<tr>
<th>Network Engineering</th>
<th>Network Investment</th>
<th>Customer</th>
<th>Energy Market</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage excursions</td>
<td>Optionality</td>
<td>Variability between customers</td>
<td>Elasticity</td>
</tr>
<tr>
<td>Thermal loading</td>
<td>Flexibility</td>
<td>Diversity</td>
<td>Variability in flexibility services</td>
</tr>
<tr>
<td>Asset condition</td>
<td>Economies of Scale</td>
<td>Clustering of LCT adoption</td>
<td></td>
</tr>
<tr>
<td>Phase imbalance</td>
<td>Coherence</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Security of supply</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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*Table 1: Examples of techno-economic distribution network modelling dimensions*
In order to address these dimensions and challenges, models of the distribution network tend to take one of several possible approaches, described in more detail below.

**Top-down models:** Models of this nature tend to involve significant amounts of abstraction and simplification in order to try to capture the broad evolution of the distribution system. These sorts of models might enable a wider range of “dimensions” to be considered – e.g. both technical impacts and commercial/economic factors – but these will, by necessity, have to be represented in the model in a simpler manner.

**Bottom-up models:** These models provide a much more thorough and detailed representation of the actual structure and dynamics of part of the system. However, because of the complexity and scale of the problem, this means they will tend to focus on looking in detail at a smaller number of facets of the problem. For example, a bottom-up model might study the technical impacts of a future scenario on a small number of real parts of the network, but won’t try to determine the cost or social impact associated with this or to consider the variety of impacts across an entire network.

**Simple models:** For some applications a simple model might suffice, which doesn’t consider much granular detail and doesn’t consider many “facets” of the problem. For example, a model of this nature might work by projecting forward the capacity requirements of some typical substations under multiple future scenarios, and converting this to a cost using different £/MW rates for different intervention strategies.

These models are plotted in Figure 1 in terms of number of dimensions and granularity.

In GB, two pieces of pioneering analysis of the GB distribution network undertaken by the industry wide Smart Grid Forum are instructive for illustrating some of the trade-offs of different approaches.

**Workstream 3:** Through this work [7], a model was developed which could simulate the expected investment requirements of the GB distribution network over long timescales (out to 2050) under a range of future scenarios. This model accounted for technical network impacts, energy and power usage by different types of customer, interactions with the wider electricity market, the investment processes and interventions used by DNOs to address network issues, and wider commercial aspects of a DNOs business (including different investment strategies). The model was largely implemented in Excel, without detailed analysis of power flows on the distribution network. This is therefore more of a “top-down” model, which is able to consider a number of facets at a large scale, but not in a huge amount of detail.

**Workstream 7:** In this work [8], detailed power systems models were built of four archetypal distribution network topologies (e.g. urban, rural etc). The impact of future technologies and scenarios on these networks was studied in considerable detail, accounting for a detailed investigation of a wide range of technical phenomena. The implications of this were thoroughly discussed, however, no attempt was made to extrapolate these impacts across the rest of the country, or to translate these impacts into costs. This is therefore more of a “bottom-up” model, which considers one facet of a small part of the network in a high level of detail.

**MERGE:** The MERGE project mission was to evaluate of the impacts that EV will have on the EU electric power systems regarding planning, operation and market functioning [9]. Steady state grid analysis was performed for three EU countries (Spain, Portugal and Greece) including various distribution networks (rural, urban and touristic). The impact of EV presence in system operation was analysed in terms of branch congestion levels, energy losses and voltage profiles, in a bottom up manner.
Transparency: One other challenge (which is not strictly a modelling challenge) is that there is often an underlying requirement for models of this nature to be transparent for all stakeholders. Techno-economic models of the distribution networks inform many important strategic and policy decisions, and many informed and engaged stakeholders may have an interest in both the outputs of these models and how these outputs were produced. This might constrain the level of sophistication which can be used within such models, which might in turn limit their ability to account for some of the complex factors described above. For example, there is often a constraint that models like this are built and operated using Excel so that any stakeholders can pick them up and explore them.

3. Advanced modelling techniques

We have explored a number of advanced modelling techniques that enable an increase in both the number of the dimensions that can be considered and the granularity, without adding significantly to computational time. These are described below in the context of a distribution investment model methodology. We have developed and tested this methodology on a number of representative GB distribution networks.

For strategic network planning, a number of representative network models (e.g. urban, rural) can be built in a power flow modelling software as shown in Figure 2. These can be modelled as a ‘slice’ of the network from EHV down to the LV to capture holistic voltage behaviour for example. At LV, the models should enable the variance of impact due to LCTs due to network type, existing capacity and clustering of LCTs to be captured. This allows for identification of “whole system” issues: for example, during summer when demand is low and PV output is high, high generation output on an 11kV network can cause overvoltages on the LV system, due to the lack of automatic voltage control, as the primary voltage of the 11kV/400V transformer changes. This wouldn’t be observed in a typical model that considers every voltage level in isolation.

Characterisation of network performance for future load scenario and representative network models can then be undertaken by combining several approaches:

Network Emulator Model

In this novel approach, an ‘emulator’ network model is created using outputs from ‘full’ AC load flow models. The thermal and voltage response of the network to a wide range of input loads is modelled (based on 1000’s of different snapshots of demand and generation loads). Taking a subset (typically 80%) of this data, an equation is fitted for each node and branch that regresses the outputs against the inputs. This can be for all nodes or pre-selected nodes likely to be most heavily loaded or at risk of voltage issues such as cable incomers to transformers and ends of feeder. This reduces computational run time with fewer nodes. The remaining 20% of the data is used to validate the regression. It should be noted that voltage interactions can be more complex however, multivariate and non-linear regressions can be used to describe these. Equally, the approach can be applied to both radial and meshed networks. Simple linear regression is illustrated here however, an emulator approach could be based on Gaussian processes, neural networks etc as needed.
Modelling of Variability Between Customers

Customer loads are typically based on historical time series data for higher voltage networks, based on historic SCADA data. For LV networks, it is common to use assumptions about the demand per customer, e.g. After Diversity Maximum Demand (ADMD) values. These give a single value of per customer demand for one or more customer types, which are consistent across the whole network. Even though the variability demand between different customers (even of the same type) is significant (particularly at low voltage), ADMDs are generally high enough that they are almost certain to provide sufficient capacity for all customers. There is a risk that this leads to over-engineered networks, but as DNOs tend to only have a limited number of discrete asset sizes to choose from, this risk has historically been reasonably low.

While these simple assumptions may have been appropriate for sizing traditional assets, they will not be appropriate when trying to determine the remaining capacity on a network (e.g. the capacity for connecting EVs and heat pumps) or when assessing the feasibility of some flexibility measures. However, these sorts of assumptions are frequently used in strategic distribution network modelling, treating all customers of the same type as if they have exactly the same patterns of demand. This could have a significant impact on the outputs of these sorts of models, particularly where significant new loads are being added. This is likely to mask the “skew” of costs towards more highly loaded networks as well as affect the...
Modelling Interventions

In network planning, once a thermal constraint or voltage issue has been identified, a network intervention is optioneered and deployed. The network planner’s decision-making process is driven by a number of factors (some subjective) but at a high level, the intervention is selected on the basis of the capacity it provides and its lifetime cost. This can be modelled within a reasonably simple cost minimisation problem.

In our approach, a cost function is used, similar to other industry models [7]. This cost function accounts for factors including disruption costs, cross-network benefits, life expectancy, and the flexibility of the solution, as well as capex and opex. It also includes an estimate of associated enabler costs, wider scale changes such as monitoring or control that would be required for a new solution. Therefore, the cost function accounts for many of the wider factors a DNO would consider when making an investment in their network rather than just the total cost of the solution. These factors are represented in terms of ‘costs’ in the optimisation model, to allow for their consideration, however only the actual capex and opex are used when appraising the cost to the DNO. These estimated costs are then used within a constrained optimisation algorithm, to find the lowest cost combination of solutions that can address the constraints that have arisen on the network.

This approach can be used to represent market-based interventions such as smart charging, and DSR however, accounting for the influence of price elasticity can become complex and, in some cases, may be better captured through load inputs rather than ‘interventions’.

4. Conclusions

In this paper, we have set out some advanced modelling techniques that can be used to expand both the granularity of strategic distribution network modelling as well as the number of “dimensions” that such models can consider. However, as Table 1 suggests, the number of factors that might need to be considered in these models is very extensive. Also, as this paper highlights, the inclusion...
of these factors typically needs to be balanced against an overarching requirement for transparency, so that all stakeholders can understand the operation and output of the models.

As a result, there are some fundamental limits to what can practically be achieved in a single techno-economic model for strategic planning purposes. Realistically, no model can account for all of these factors while still being accessible to those that weren’t initially involved in developing it. Therefore, it is important that analysts are clear about what questions they are trying to use the model to answer, in order to focus the analysis on those factors that are most material to the particular question. This means that analysis and stakeholders need to balance the materiality of different factors alongside the tractability of including them in the model.

One important question that might help focus the scope of such a model is whether the model needs to be capable of determining the absolute cost of some future scenarios or just to compare the relative costs between scenarios. The former might be required, for example, when agreeing a price control between the regulator and the distribution network company. In these situations, it will be important for the network company to understand the range of possible costs as well as the variables which drive this, so that this uncertainty can be accounted for in the structure of the price control. On the other hand, models which calculate the relative cost between scenarios may be sufficient if trying to make broader policy decisions, where each policy might lead to a different scenario outcome. In these cases, it may be justifiable to simplify or abstract some aspects of the model. However, in these cases, care should be taken when making comparisons between the outputs of this model with any other metrics.

Finally, it is important that such models represent the reality of the actual network planning and investment decision making processes they are representing. This might also limit the ability to make models more sophisticated, as the models should not be more sophisticated than the real processes. For example, the risk-based customer demand model approach described in this behaviour would require a clear articulation of how these risks are accounted for in network planning by, for example, defining the level of risk to which networks are designed. Therefore, it would be difficult to incorporate such a risk-based approach into a strategic model until it was also incorporated within the day-to-day decision-making processes of the distribution company1.

5. Bibliography


1 - However, this also suggests that such a model could be used to determine the benefits of employing a risk-based approach.
A surrogate-assisted modeling and optimization method for planning communication system in distribution network cyber-physical system

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CHINA

Summary
The development of industrial informatization stimulates the implementation of cyber-physical system (CPS) in distribution network. As a close integration of the power network infrastructure with cyber system, the research of design methodology and tools for CPS has gained wide spread interest considering the heterogeneous characteristic. To address the problem of planning communication system in distribution network CPS, at first, this paper proposed an optimization model utilizing topology potential equilibrium. The mutual influence of nodes and the spatial distribution of topological structure is mathematically described. Then, facing the complex optimization problem in binary space with multiple constraints, a novel binary bare bones fireworks algorithm (BBBFA) with a surrogate-assisted model is proposed. In the proposed algorithm, the surrogate model, a back propagation neural network, replaces the complex constraints by incremental approximation of nonlinear constraint functions for reducing the difficulty in finding the optimal solution. The communication system planning of IEEE 39-bus power system, which comprises four terminal units, was optimized. Considering the different heterogeneous degrees, four programs were involved in planning for practical considerations. The simulation results of the proposed algorithm were compared with other representative methods, which demonstrated the effective performance of the proposed method to solve communication system planning for optimizing problems of distribution network.

1. Introduction
Cyber-physical system (CPS) is proposed with the development of industrial informatization. In distribution network, the new concept emphasizes the close integration of the power network infrastructure as the physical systems, and information sensing, processing, intelligence, and control as the cyber system [1]. Over the last few years, significant progresses have been made in CPSs, which are boosted mainly by three emerging trends, namely, data proliferation [2], large-scale integration [3], and autonomy [4]. However, there is still a long way to go to reach its full potential [5, 6]. To enable seamless integration of control, communication, and computation for rapid design and deployment of CPS, the plan of communication system are becoming essential, which allows the heterogeneous systems to be composed in a plug-and-play fashion with optimal safety state [4].

As an important aspect of CPS, communication represents the information exchange and signal links between sensors, computational units and actuators of cyber-physical systems. The communication network of distribution network usually contains master station, substation units, CPS terminals, and physical connection lines [7]. CPS terminals are further classified as feeder terminal, distribution terminal, distributed energy terminal. Each terminal has its specific service object like relay protection, distribution automation, business electricity information collection, distributed cooperative control, production management, environmental monitoring, and so forth [8]. Hence, considering these heterogeneous components and meeting the requirements, an optimal CPS communication system is imperative to design.

In previous studies, the homogeneous characteristics of system are primarily focused [9-12]. To better understand
and design communication system based on its effects on physical system, more emphases are given in the heterogeneity of communication capabilities [13-15]. In this paper, firstly, a topology potential equilibrium model is proposed to handle the communication planning problem in distribution network with fully heterogeneous characteristics considerations, which defined the generalized node quality for heterogeneous CPS terminals. Then, the mutual influence of nodes and the spatial distribution of topological structure is mathematically described [8]. Such model with high dimensionality, discrete space, and multiple constraints makes the communication system planning as a NP-complete optimization problem. As a result, an efficient binary optimization tool is going to be proposed.

Improved swarm-based optimization algorithm can be used to solve the above problem because of the strong population-based search capability, fast convergence, and robustness of these algorithms. However, the solving process may face the danger of being trapped in local optimal, leading to poor convergence performance and the clustered solutions distributed in infeasible regions [16-18]. Inspired by the phenomenon of fireworks explosion, Tan proposed a new swarm-based fireworks algorithm (FA) [19]. Numerical experiments tested on a number of benchmark functions show that FA exhibits improved performance than other typical algorithms [20], including particle swarm optimization (PSO) and genetic algorithm (GA). Some improved versions FA to solve single-objective [21-23] or multi-objective optimizations have been proposed [24-26]. However, there are still several shortcomings in the conventional fireworks algorithm and improved versions. And few studies have applied binary FA in discrete space.

To handle the practical problems meanwhile overcoming the preceding shortcomings, this paper proposes a novel binary bare bones fireworks algorithm (BBBFA) with a surrogate-assisted model. The surrogate model is implemented to replace the complex constraints by incremental approximation of nonlinear constraint functions. As a result, the feasible region based on the approximate constraint functions will be much simpler, and the isolated regions will become more likely connected, which reduces the difficulty in finding the optimal solution. An IEEE classic example, IEEE 39-bus power system, is adopted in the simulation to demonstrate the effectiveness of the proposed method where the improved results are presented.

The rest of this paper is organized as follows: Section 2 formulates the problem of planning communication system in distribution network cyber-physical system. Section 3 describes the backgrounds of the proposed optimization method. Section 4 explains the principle and implementation of the proposed algorithm. Section 5 presents simulation results and discussion. Finally, Section 6 concludes the paper.

2. The optimization of planning communication system

With predefined generalized node quality, the communication system planning problem can be mathematically modelled by topological potential equilibrium [8]. The concept of topological potential is based on data field theory in cognitive physics [27]. A network can be regarded as a physical system which contains several nodes. Figure 1 presents a topology of CPS on IEEE 39-bus power system. Each of node represents a field source, and they all interact with each other. Nodes in the network structure are affected by their own role, but also by the roles of neighbours. Specially, the terminals in distribution network CPS are regarded as heterogeneous nodes from communication requirement and information models. This common influence produces the potential value of nodes which is described as topological potential. The potential functions in communication system for distribution network can be expressed as follows:

\begin{equation}
\phi(i) = \sum_{j=1}^{n} \phi_j(i)
\end{equation}

\begin{equation}
\phi_j(i) = m \times e^{-|i-j| \sigma}
\end{equation}

where $i$ and $j$ represent the terminal node in communication system. $\phi(i)$ is the algebraic sum of potential in $i$th communication node produced by all $n$ communication nodes. The potential value $\phi(i)$ is generated by the node $j$ at the node $i$. $m$ is the quality of node object $j$. $|i-j|$ is the distance between the the nodes $i$ and $j$. $\sigma$ is used to control the interactive force among node objects, and $k$ represents the distance index.
The third one is service constraint where bandwidth and delay conditions of communication link must be met [29]:

\[ \sum_{e \in F(S_j)} S_j > (1 - \beta) \cdot B \]
\[ \sum_{P(S_j)} \Delta t < \bar{R}_{\text{delay}}(S_j) \]

where \( S_j \) is an exchange network service. \( P(S_j) \) is the service transmission path. \( B \) is the total bandwidth of link. \( \beta \) reserves the percentage bandwidth for the link, which guarantees the real-time transmission of protocol control message. \( \Delta t \) is the time delay, and \( \bar{R}_{\text{delay}}(S_j) \) is the upper limit of delay requirement.

3. The backgrounds of bare bones fireworks algorithm

FA is a heuristic algorithm inspired by the phenomenon of fireworks explosion. During each generation, the algorithm selects quality points as fireworks, which generate two types of sparks to search the local space around them. The evolutionary process continues until at least one spark reaches a desired optimum or the criterion to stop is satisfied. The basic framework of FA [19] is shown in Figure 2.

Numerical experiments tested on a number of benchmark functions show that FA exhibits improved performance than other typical algorithms. However, there are still several drawbacks in the conventional fireworks algorithm and improved versions. Firstly, the

For the node quality, value \( m \) is different for its multisource heterogeneous characteristic of distribution network CPS. In order to assess the weight of nodes, generalized node quality is defined by analytic hierarchy process (AHP) [8, 28]. In this paper, unit nodes in distribution network CPS are classified into masters and terminals. According to the reference 28, the generalized node quality of terminal nodes, as shown in Table 1, is calculated from three layers setting. This part goes beyond the scope of this article, and more details can be seen in reference 28. Furthermore, to evaluate the algorithm’s performance under different heterogeneous characteristics, four programs are set. And, from 1st to 4th program, the heterogeneous degree becomes deeper.

The topological potential theory could accurately represent the weight of each node in networks. Distributing the topological potential equally would improve the reliability of the network to resist the attack or units’ fault. The objective function of optimization problem can be written as:

\[ \min F(G) = \sum_{i=1}^{n} \frac{1}{n} (\varphi_i - \bar{\varphi})^2. \]  

In order to make the communication system of distribution network safe and stable, the following constraints must be met for every optimization horizon. The first one is that each unit node should have at least two connected links to ensure network’s connectivity:

\[ \eta(i) \geq 2. \]  

The second constraint is the maximum communication distance between two communication nodes as follows:

\[ \|i - j\| \leq D_{\max}. \]  

Table 1: The Node quality of unit nodes

<table>
<thead>
<tr>
<th>Node types</th>
<th>Node label</th>
<th>1st program</th>
<th>2nd program</th>
<th>3rd program</th>
<th>4th program</th>
</tr>
</thead>
<tbody>
<tr>
<td>Master station</td>
<td>8</td>
<td>0.2</td>
<td>0.3</td>
<td>0.45</td>
<td>0.55</td>
</tr>
<tr>
<td>Distribution terminal</td>
<td>1, 2, 3, 9, 13, 15, 16</td>
<td>0.2</td>
<td>0.2</td>
<td>0.15</td>
<td>0.1</td>
</tr>
<tr>
<td>Transformer terminal</td>
<td>5, 6, 7, 10, 11, 12, 14</td>
<td>0.2</td>
<td>0.2</td>
<td>0.13</td>
<td>0.1</td>
</tr>
<tr>
<td>Distribution energy</td>
<td>4, 17</td>
<td>0.2</td>
<td>0.25</td>
<td>0.15</td>
<td>0.5</td>
</tr>
</tbody>
</table>
from objective function. Then, the explosion amplitude $A = (A_1, \ldots, A_d, \ldots, A_D) \in \mathbb{R}^D$ is calculated based on the $ub$ and $lb$. When the termination criterion is not met, optimization process is carried out iteratively. In each iteration, $n$ explosion sparks are generated uniformly within a hyperrectangle bounded by $x - A$ and $x + A$ from $x$. For every one spark $s_i \in n$, the fitness is calculated. Afterwards, the core firework will be updated by the optimal spark in current iteration. And the explosion amplitude will be multiplied by an amplification coefficient $C_a > 1$. Otherwise, the explosion amplitude will be multiplied by a reduction coefficient $C_r < 1$ and the current core firework will be kept.

In the BBFA, only three parameters ($n$, $C_a$, $C_r$) need to be set up. Algorithm convergence and optimal parameter selection have been fully discussed in reference 16. And BBFA with parameter (300, 1.2, 0.9) shows competitive performance on the CEC13 benchmark suite compared with other versions of fireworks algorithm and typical meta-heuristics. The following four advantages have been fully proved [16]:

1. It is extremely easy to implement.
2. It has very few parameters.
3. Its computational complexity is linear.
4. Its performance is competitive.

4. The binary bare bones fireworks algorithm with surrogate model

4.1 Binary BBFA

When solving the communication planning problem with topological potential function in Section 2, the position of each particle in algorithm can be encoded

The pseudocode of BBFA as follows:

1: sample $x \sim U(lb, ub)$
2: evaluate $f(x)$
3: $A = ub - lb$
4: while termination criterion is not met
5:   for $i = 1$ to $n$ do
6:       sample $s_i \sim U(x - A, x + A)$
7:       evaluate $f(s_i)$
8:   end for
9: if min ($f(s_i)$) < $f(x)$ then
10:    $x = \arg\min f(s_i)$
11:    $A = C_a A$
12: else
13:    $A = C_r A$
14: end if
15: end while
16: return $x$

Firstly, one core firework $x = (x_1, \ldots, x_d, \ldots, x_D)$, are randomly initialized in solution space within the lower and upper $(lb$ and $ub \in R^D)$ boundaries, and its spatial dimension is $D$. $f(x)$ is the fitness value of core firework
into binary mode, and one particle position represents a communication topology solution. In discrete binary environment, each dimension component of particle position is limited to 0 or 1. 1 means that the location of the corresponding communication link exists, and 0 means the opposite. Moving through a dimension means that the corresponding variable value changes from 0 to 1 or vice versa. The main difference between continuous and binary BBFA is that in the binary algorithm the sparks position generating means a switching between 0 and 1.

In order to introduce a binary mode to the BBFA, this switching can be done according to the explosion amplitude A. The idea is to generate the new position in a manner that the current bit value is changed with a probability that is calculated according to the explosion amplitude. In other words, BBBFA considers generating new positions to be either 1 or 0 with a given probability. In continuous BBFA, the core updating idea of explosion amplitude A is described as follows: if in one generation no better solution is found (in 13 line of BBFA pseudocode, $C_r < 1$), that means the explosion amplitude is too aggressive and thus needs to be reduced to increase the probability of finding a better solution, and otherwise it may be too conservative to make the largest progress and thus needs to be amplified (in 11 line of BBFA pseudocode, $C_a > 1$). With this dynamic control, the algorithm can keep the amplitude appropriate for the search. That is, the dynamic explosion amplitude is long in early phases to perform exploration, and is short in late phases to perform exploitation.

Based on the above the discussion of the searching mechanism, a larger explosion amplitude A provides a high probability of changing the position for performing exploration. A smaller or zero value A often appears in the late phases to local exploit with the low probability changing. Therefore, a transfer function to map the explosion amplitude to the probability of position generating can be proposed:

$$T(A^d) = \|\tanh(A^d)\|.$$  \hspace{1cm} (8)

Probability $T(A^d)$ is calculated based on the explosion amplitude value on each dimension of $A$. Figure 3 illustrates the Equation 8. The sparks position generating rule in BBBFA can be shown as follows:

IF $\text{rand} < T(A^d)$ then $s^d_i(t+1) = \text{complement}(x^d(t))$
else $s^d_i(t+1) = x^d(t)$.

Figure 3: The transfer function $\|\tanh(Ad)\|$
4.2 The surrogate-assisted model

As presented in the Section 2, there are four complex constraints (inequations 4-8) in optimization model, which separate the feasible regions of solution space as shown in Figure 4. It imposes big difficulties for iterative optimization. Aim at this situation, surrogate models [35] are built for each constraint function with an increasing accuracy starting from the simple linear approximation, when BBBFA is implemented on planning communication system in distribution network cyber-physical system.

Specifically, in this paper, a neural network model is trained as surrogate model for each constraint function with an increasing number of training data. In the beginning, a very small number of training data are sampled from the constraint functions, and only a rough linear approximation of the nonlinear constraint functions can be achieved. As the iterative optimization proceeds, additional data points are sampled, which results an increasingly accurate approximation. At the end of process, the original constraint functions are switched back to ensure that the obtained optimal solution is feasible. The entire process can be explained in Figure 5 with two constraints as example.

The back propagation neural network with one hidden layer is adopted for approximating the nonlinear constraints. Both the hidden neurons and the output neurons use a tan-sigmoid transfer function. The number of input nodes equals the dimension of solution space plus one (a constant input as threshold). The number of hidden nodes is set to three times that of the input nodes, and the number of output node is one. According to the empirical analysis in Reference [17], at iterations $t = (t + 10k^2)$ the neural network models are to be updated, where $k = 0, 1, 2, ..., k_{max}$ and $t$ is the iteration time beginning from 1. Furthermore, in the optimization process, an extra competition will be carried out, which the original constraints compare with the approximate constraints in terms of the number of feasible solutions. If the original constraint function produces more feasible solutions than the approximate constraint function, the original constraint function will be used for checking the feasible solutions. Otherwise, the approximate constraint function will be used.

In summary, the algorithm optimization solving process for planning communication system in distribution network cyber-physical system is as follows:

**Step 1.** Set algorithm parameters: $n, C_a, C_r$. Providing the data of distribution network is required. The information includes the node quality of communication terminals and constraints limiting values.

**Step 2.** One core firework $x = (x_1, ..., x_d, ..., x_D)$ is randomly initialized in binary mode and checked. Here, lower and upper boundaries are set as -2 and 2 respectively. Then, every dimension of the explosion amplitude $A_d$ is gotten, $A_d = \text{rand} \times (\text{ub} - \text{lb}) + \text{lb}$.

**Step 3.** Iterative improvements. Firstly, the current iteration time is checked, which decides whether to establish ($t = 1$) or update the surrogate model. $s_i$ sparks are generated based on Equation 8. The feasibilities are checked for the new sparks referring to the original or approximated constraints.

**Step 4.** The objective values of the new sparks are calculated. The core firework and explosion amplitude $A$ are updated. If the iteration reaches the termination criterion, the algorithm stops and returns the best core firework $x$; otherwise, Step 3 and 4 are repeated.

5. Simulation results

In this section, the proposed binary bare bones fireworks algorithm with surrogate model assisting is implemented to solve the problem of planning communication system for IEEE 39-bus power system as shown in Figure 1. In order to better test the optimization accuracy and convergence speed of BBBFA, a pair of standard minimization and maximization benchmark functions in binary search space were firstly selected for experiments as given in the Table 2.
Max-Ones function could be concluded from Figure 6 (b). It can be seen from above results that BBBFA has the good convergence accuracy and speed when dealing with discrete benchmark optimization problems comparing with other representative algorithms. Then, facing the practical communication system planning problem with multiple constraints, the initial network of communication system is established as Figure 1 to be optimized.

The parameter settings of BBBFA are the same as above, and the setting of back propagation neural network refers to section 4.2. The maximum number of iterations is set to 1000, and the average results of 10 independent experiments are presented. The statistical results show that the binary BBFA algorithm can converge to global optimization in 80 times of iteration. Compared with the convergence of binary PSO algorithm at 150 times [8], BBBFA has better convergence speed. Considering the different heterogeneous degrees, four programs as listed in Table 1 are involved in planning for practical considerations. Take program 1 as an example, the distribution of topological potential is obvious with high heterogeneity in the initial network as the histograms in Figure 7(a). The proposed method with surrogate model effectively balances the topological potential distribution as shown in Figure 7(b). The node 8, as the main station unit, has the highest node topological potential in initial network. After optimization, its topological potential is similar to that of other nodes, which improves the reliability of the network to resist the attack or units’ fault. In order to further illustrate the effectiveness of the proposed method, the network performance function is employed to compare the performance of the optimized network before and after. The network performance function represents the

<table>
<thead>
<tr>
<th>Test function</th>
<th>Global minimum/maximum</th>
<th>Search space</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max-Ones ( \sum_{i=1}^{m} x_i )</td>
<td>0</td>
<td>([0, 1]^m)</td>
</tr>
<tr>
<td>Royal-Road ( \sum_{i=1}^{m} \prod_{j=1}^{n} x_j )</td>
<td>20 ((m = 160))</td>
<td>([0, 1]^m)</td>
</tr>
</tbody>
</table>

The functions of Table 2 are binary in nature, which are described only in binary space 0-1 values. In this paper, we set Max-Ones function as minimization problem, and the Royal-Road function is gonna to be maximized. \(m\) is the dimension of the function. For the proposed BBFBA algorithm, the sparks population size is set to 300 \((n = 300)\), and \(C_a\) and \(C_r\) are set as 1.2 and 0.9 respectively. Only the three algorithm parameters need to be set here. To evaluate the ability of the proposed algorithms, \(m\) is set as 160, therefore the dimension of particles is equal to \(m\). The results are compared with the binary gravitational search algorithm (BGSA) which has been confirmed having the best efficiency among two representative swarm intelligence algorithms: GA and binary particle swarm optimization (BPSO) [36]. For BGSA, the number of initial particles is set as 50, and other parameters refer to reference 36. The maximum number of iterations is set to 1000, and performance evaluation of optimization algorithms with 20 trials is presented. The mean convergence curves and optimals of BGSA and BBBFA for the benchmark functions are given in Figure 6.

For the Max-Ones function, both BBBFA and BGSA obtain the optimal solution in 1000 iterations as shown in Figure 6 (a). However, BBBFA has a competitive performance on the convergence speed. Under the 20 repeated trials, BBBFA obtained the optimal value at 219 iterations, while BGSA did not get the optimal value until 744 iterations. For the maximization problem of Royal-Road function, BBBFA finds the optimal value, but BGSA only gets the value of 18.8 in 1000 iteration times. In addition, the good convergence rate of BBBFA for Max-Ones function could be concluded from Figure 6 (b).

It can be seen from above results that BBBFA has the good convergence accuracy and speed when dealing with discrete benchmark optimization problems comparing with other representative algorithms. Then, facing the practical communication system planning problem with multiple constraints, the initial network of communication system is established as Figure 1 to be optimized.

The parameter settings of BBBFA are the same as above, and the setting of back propagation neural network refers to section 4.2. The maximum number of iterations is set to 1000, and the average results of 10 independent experiments are presented.

The statistical results show that the binary BBFA algorithm can converge to global optimization in 80 times of iteration. Compared with the convergence of binary PSO algorithm at 150 times [8], BBBFA has better convergence speed. Considering the different heterogeneous degrees, four programs as listed in Table 1 are involved in planning for practical considerations. Take program 1 as an example, the distribution of topological potential is obvious with high heterogeneity in the initial network as the histograms in Figure 7(a). The proposed method with surrogate model effectively balances the topological potential distribution as shown in Figure 7(b). The node 8, as the main station unit, has the highest node topological potential in initial network. After optimization, its topological potential is similar to that of other nodes, which improves the reliability of the network to resist the attack or units’ fault. In order to further illustrate the effectiveness of the proposed method, the network performance function is employed to compare the performance of the optimized network before and after. The network performance function represents the

![Figure 6: Comparison of the mean convergence curves and optimals between BGSA and BBBFA for the benchmark functions](image)
transmission of information in the most effective and shortest feasible path, and is a measure of the network structure [37], which is calculated as follows:

\[ E(G) = \frac{1}{n(n-1)} \sum_{i<j} \frac{1}{d_{ij}} \]

(9)

is the shortest path between node i and node j. For the four programs in the simulation, the comparison results are given in Table 3. The larger of E(G) value is, the better of efficiency in the communication network in distribution network CPS is obtained.

Table 3: Two test benchmark functions

<table>
<thead>
<tr>
<th>E(G) value</th>
<th>1st program</th>
<th>2nd program</th>
<th>3rd program</th>
<th>4th program</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial network</td>
<td>0.2269</td>
<td>0.2269</td>
<td>0.2269</td>
<td>0.2269</td>
</tr>
<tr>
<td>Optimal network</td>
<td>0.2858</td>
<td>0.2868</td>
<td>0.2847</td>
<td>0.2812</td>
</tr>
</tbody>
</table>

6. Conclusion

In this paper, the problem of planning communication system in distribution network cyber-physical system is discussed firstly, and the optimization model of planning communication system utilizing topology potential equilibrium is presented. Then, a novel BBBFA optimization algorithm is proposed to solve the complex planning scheme. In the process of optimization, the multiple constraints are simplified with the surrogate-assisted model. The experimental results show that the proposed method can balance topological potential optimization and improve the reliability of communication system in distribution network CPS.

7. Acknowledgement

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Use of PMU data for locating faults and mitigating cascading outage

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Summary

Large number of Phasor Measurement Units (PMUs) as a part of the system-wide synchrophasor monitoring system are being deployed in the USA and around the world. Transmission Operators (TOs), as well as Independent system Operators (ISOs) or Regional Transmission Operators (RTOs) are looking at leveraging this high-resolution data to improve their ability to monitor and control the grid. This paper elaborates on the use of PMU data to locate faults in the power system, and provides a prediction method for monitoring how the system behaves after complex switching actions caused by cascading events. A method for arresting cascades by performing controlled islanding is also proposed.

We first present a novel system-wide fault location method for transmission lines utilizing electromechanical wave propagation phenomena. The method uses synchrophasor measurements during disturbances obtained from phasor measurement units sparsely located in the network. The method determines the time-of-arrival of electromechanical waves propagating from the fault point to sparsely located PMUs. By taking the speed of electromechanical wave propagation as well as topology of the network into account, the method is able to detect the faulty line. Finally, by adding fictitious buses inside faulty line and applying binary search method, location of fault is accurately pinpointed. The main advantage of the proposed method is the use of limited number of existing PMUs, which reduces the cost of implementation. Test results reveal the high accuracy of the method in detecting and locating faults.

Early prediction of cascade events outages followed by immediate and proper control actions can prevent major blackouts. We introduce a novel method to predict cascade event outage at an early stage and mitigate it with proper control strategy. At the first stage, methodology employs sparsely located phasor measurement units to detect disturbances using electromechanical oscillation propagation phenomena. The obtained information from the first stage is used to update system topology and power flow results. Then an optimal graph partitioning problem is defined to predict possible cascade event scenarios and list critical transmission lines. Finally, if the cascade continues, another optimal graph partitioning problem is solved to suggest proper switching action to intentionally create islands which cause minimum load shedding and maintain voltage profile of each island.

1. Introduction

Transmission line is a vital part of the power system network. Faults are inevitable and bound to occur on overhead transmission lines due to flashover of insulators inflicted by lightning or switching surges. Transmission-line relaying involves three major tasks, namely detection, classification, and location of faults. Fast detection of transmission-line faults and accurate estimation of fault location is helpful in accessing the extent of repair work to be carried out. Various fault location methods have been presented in literature and they are categorized based on (i) single-end measurement (ii) unsynchronized/synchronized two-end measurements. The single-end measurement based methods utilize fundamental frequency components of voltage and/or current for fault distance estimation [1]-[2]. Though these methods are simple and economically viable, their accuracy might be affected by current infed and fault and system parameters. Conversely, methods based on unsynchronized multi-end measurements make

KEYWORDS

Phasor measurement units, synchrophasors, fault location, controlled islanding, electromechanical wave propagation
use of post fault voltage and current phasors to locate faults on transmission lines [3]-[4]. Despite higher accuracy of these methods compared to methods based on single end measurement, higher cost and installation requirement of measurements throughout the entire network are the major factors that restrict their feasibility. Methods related to synchronized measurements at two ends are based on Clarke transformation [5]-[6], synchronized fundamental phasor measurements [7]-[8], bus impedance matrix [9] and travelling wave [10]-[11]. Regardless of higher accuracy, requirement of a device having high sampling frequency to acquire samples of electromagnetic transients is the major limitation of the aforementioned methods. Therefore, it is necessary to design a fault location method that depends on sparse PMU measurements with relatively low sampling frequency.

Restriction on right-of-way, higher demand of power flow on limited transmission line resources and restructuring of power system may lead to cascading outages [12]-[13]. Rigorous analysis done by an IEEE task force clearly indicates that detection and mitigation of cascading outages may be possible by acquiring real-time information on system conditions. Due to installation and interconnection of hundreds of Phasor Measurement Units (PMUs) as part of the system-wide synchrophasor monitoring system in the USA, monitoring capability of the grid has been increased. It has been observed from the past-published literature that the complete prevention of blackout is difficult due to the uncertainty in system operation, weather, and human factors. Most of the cascading blackouts have a slow pace during the initial stage, and may evolve or cascade quickly when the time elapses without effective mitigating schemes. The development of strategies based on PMUs can help in mitigating the unfolding event hence avoiding a large area blackout. The developed strategies not only assist in detecting fast cascading outages but also help in predicting the path of slow cascades [14]-[15].

In order to achieve the said task, various intentional islanding schemes have been presented. These methods are based on either optimization of coherent group of generators [16]-[18] (by solving max-flow-min-cut optimization problem) or by obtaining a simplified equivalent model of power system network by solving a graph-based reduction algorithm [19]. The former methods may not be able to provide proper islanding solution due to inappropriate electromechanical modeling because of non-linear nature of power system. Conversely, the later methods could not offer optimal solution in terms of controlled islanding due to simplification process involved in achieving an equivalent model. Subsequently, control islanding schemes are also proposed based on clustering and particle swarm optimization [20]-[21]. The aforementioned methods may not consider dynamic contraints causing formation of unstable islands, which in turn may lead to total blackouts. Hence, it is desirable to develop a planned islanding scheme based on spectral clustering which yields self-sustained islands and at the same time offers high-speed performance for any size of network.

We first present a novel fault location method which utilizes electromechanical wave propagation phenomena and then introduce a method for monitoring and predicting cascading outages. The suggested control islanding method can be extened for prevention of progression of cascading outages from steady state to fast transient state leading to a major blackout.

2. Background

2.1 Fault location method

Rotors of electric generators produce oscillation (with reference to their synchronous reference frame in case of faults and other abnormalities, widely known as electromechanical wave propagation). Having a much lower frequency of the order of 0.1 to 10 Hz, these oscillations, which travel away from the disturbance source into the network at a finite speed, could be noticed by observing phase angle of bus voltages. Modeling of electromechanical wave propagation can be carried out by continuum model which represents the power system by the incremental system as shown in Fig. 1 (a). With reference to Fig. 1 (a), continuum equivalent of load flow and swing equations of the power system network are derived and used for simulation study of the proposed fault location algorithm [22].

In the proposed scheme, bus voltage and its angle along with its first and second derivative \((v, \theta, \dot{\theta}, \ddot{\theta})\) at buses
where PMUs are installed are given as input to the decision tree (DT) classifier. The structure of proposed DT classifier model, implemented in Matlab 2013R1, is shown in Fig. 1 (b) [23]. The proposed decision tree classifier model utilizes k-nearest neighbors algorithm (k-NN) for computing the Euclidean distance (D) between measured and calculated time of arrival (ToA) of electromechanical waves [24]. The closest bus near the fault would be identified based on the value of D (smaller the distance closer the bus is to the fault location). In order to further improve reliability, for each line, it is necessary to compute an index which is equal to the sum of Euclidean distance obtained for the buses at two ends of the line. The lowest value of an index pinpoints the faulty line.

In order to test the proposed approach, a real simplified utility power network, as shown in Fig. 2, is considered. The source and line parameters are already depicted in Fig. 2. Utilizing the test system, as shown in Fig. 2, 2500 (fault location × fault duration × number of lines) test cases have been generated by varying fault location (0% to 99% in steps of 1%), fault duration (10 ms to 50 ms in steps of 10 ms) and number of transmission lines (1 to 5). The 80% of total generated cases i.e. 2000 are used for training of the proposed DT classifier model whereas the remaining 20% are used for testing. The output of the proposed DT classifier model is in terms of ToA. Once ToA at each PMU installed bus (A, B and C) is obtained, calculation of measured propagation time delay matrix ($T_m$) is performed as per (1).

$$T_m = [t_{BA}, t_{CA}]$$

(1)

where, $t_{BA}$ and $t_{CA}$ is the electromechanical-wave propagation delay from fault point to various buses where PMUs are installed with respect to ToA of electromechanical wave at bus A.

Thereafter, the theoretical shortest propagation time delay from various PMU installed buses with respect to bus A is calculated by (2). Here, the shortest time delay path for each bus pair is computed utilizing the Dijkstra's algorithm [25].

$$T_{sp-x} = [\tau_{BAx}, \tau_{CAx}]$$

(2)

where, $\tau_{BAx}$ and $\tau_{CAx}$ is the theoretical shortest propagation time delay from various PMU installed buses to an arbitrary bus $x$, respectively, with reference to bus A.
Finally, the difference (ε) between (2) and (1) is obtained for all buses. Here, the task is to find the bus that corresponds to the minimum value of (ε). After finding the faulty line, the next task of calculation of exact fault location is achieved by adding fictitious buses and splitting the faulty line in to two line segments based on binary search approach [26].

Testing of the proposed method is carried out using the sample test system (Fig. 2). Various cases based on variation in fault location, duration of fault and number of lines have been performed. The results for few sample cases are presented in Table I. It is to be noted from Table I that the error in the estimation of fault location remains less than 2% even with varying simulation parameters.

2.2 Controlled islanding scheme

Blackouts have been happening during the course of the history of interconnected power system network [27]. In this situation, the stability margin of the system reduces, which in turn leads to the formation of unstable islands. The possibility of catastrophic failure of power system can be avoided by performing intentional islanding of the grid based on spectral clustering formulation. As the intentional islanding is multi-constraint and multi-objective optimization problem, it would be difficult to obtain optimal solution. In the proposed scheme, power flow disruption between islands is considered as the objective function whereas generator coherency is taken as the constraint function. The power flow disruption is defined as the absolute value of the active power flow between islands. The desired number of coherent groups are obtained by performing recursive bisection spectral clustering. Finally, the islanding solution is obtained by applying constrained spectral k-embedded clustering algorithm. The step-by-step procedure is explained in [28]. Fig. 3 shows one line diagram of IEEE 118-bus system.

After numerous sequential line and/or unit outages and without application of the proposed controlled islanding scheme, there is a possibility of disconnection of loosely connected areas lacking proper balance between group of generators and loads. In this case, load shedding is the only option to avoid blackout. Conversely, as shown in Fig. 3, application of the proposed controlled islanding scheme for the same system creates two islands. The outcome of the proposed scheme is depicted in Table II. As shown in Table II, the suggested island preserves the balance between load and generation with minimal load shedding. At the same time, generator coherency is also fulfilled.

<table>
<thead>
<tr>
<th>Actual fault location (%)</th>
<th>Fault on line-5</th>
<th></th>
<th>Fault on line-3</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>10 20 30 40</td>
<td>Distance estimated by DT (%)</td>
<td>Error (%)</td>
<td>Distance estimated by DT (%)</td>
<td>Error (%)</td>
</tr>
<tr>
<td>0.1 0.11 1.0 0.12 2.0</td>
<td>0.11 0.11 1.0 0.12 2.0</td>
<td>0.11 0.11 1.0 0.12 2.0</td>
<td>0.11 0.11 1.0 0.12 2.0</td>
<td>0.11 0.11 1.0 0.12 2.0</td>
</tr>
<tr>
<td>0.4 0.38 2.0 0.38 2.0</td>
<td>0.38 0.38 2.0 0.38 2.0</td>
<td>0.38 0.38 2.0 0.38 2.0</td>
<td>0.38 0.38 2.0 0.38 2.0</td>
<td>0.38 0.38 2.0 0.38 2.0</td>
</tr>
<tr>
<td>0.7 0.71 1.0 0.72 2.0</td>
<td>0.71 0.71 1.0 0.72 2.0</td>
<td>0.71 0.71 1.0 0.72 2.0</td>
<td>0.71 0.71 1.0 0.72 2.0</td>
<td>0.71 0.71 1.0 0.72 2.0</td>
</tr>
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<td>0.9 0.88 2.0 0.88 2.0</td>
<td>0.88 0.88 2.0 0.88 2.0</td>
<td>0.88 0.88 2.0 0.88 2.0</td>
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<tr>
<td>0.95 0.96 1.0 0.955 0.5</td>
<td>0.96 0.96 1.0 0.955 0.5</td>
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<td>0.96 0.96 1.0 0.955 0.5</td>
<td>0.96 0.96 1.0 0.955 0.5</td>
</tr>
</tbody>
</table>
running at control center via Phasor Data Concentrators (PDCs). It has been demonstrated that the fault location algorithm is reliable and accurate.

3.2 Controlled islanding

In order to check performance of the proposed controlled islanding scheme, synchrophasor testbed environment, as shown in Fig. 5, has been developed. The European high voltage transmission network containing 1354 buses, 260 generators and 1991 branches is modeled...
situations and critical transmission lines are predicted based on optimal graph partitioning problem. Lastly, the presented technique suggests suitable switching action by solving additional optimal graph partitioning problem such that voltage and frequency of the island remains within prescribed limit along with minimal load shedding.

The proposed tools might act as a powerful means for power system operator trying to maintain system operation by monitoring faults and deciding on any alternate use of transmission lines, and also detecting and arresting cascade outages at early stages to prevent severe blackouts.

4. Conclusion

In this paper, a new fault distance estimation technique for transmission lines is presented which uses electromechanical wave propagation phenomena. Utilizing synchrophasor measurements obtained by sparsely located PMUs at the time of disturbances, the technique calculates ToA of electromechanical waves propagating from fault point to the location of PMUs. Considering speed of electromechanical wave propagation, topology of the network and applying binary search method, the proposed technique correctly estimates the location of fault with an average error of less than 2%. This algorithm has been implemented and tested on synchrophasor application testbed to prove the accuracy.

A novel synchrophasor based controlled islanding method is also presented which not only predicts cascading event at an early stage but also mitigates it with appropriate control strategy. Primarily, the presented technique updates topology of the system and load flow results by sensing disturbances based on electromechanical wave propagation phenomena with the help of sparsely located PMUs. Afterwards, probable cascade incident

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Redundant secure timing sources and timing distribution to digital power protection and control applications

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Summary
The power transmission system is increasingly dependent on accurate time-stamping of digitally sampled values used for protection and control. In particular, real-time streaming of data from networked Phasor Measurement Units (PMUs) for wide area ‘closed loop’ automated control applications implies a critical dependence of accurate, available, and reliable microsecond-level timing.

While microsecond accuracy is easily met by GNSS timing receivers, GNSS signals for open civilian use are weak and also lack effective authentication mechanisms. GNSS timing receivers are therefore vulnerable to interference from malicious or inadvertent radio noise (jamming) and susceptible to ‘spoofing’ with generated GNSS-signals containing misleading timing and navigation data.

The overall goal of the COSECTIME project funded by Statnett is to demonstrate the applicability of state-of-the-art fiber-optic time transfer techniques for traceable, secure and redundant synchronization of digital power transmission protection and control applications. In full deployment, the transmission system operator (TSO) will generate redundant autonomous UTC-traceable atomic timescales and distribute timing through redundant fiber optic networks also under TSO control. Here we present results from a pilot demonstration of timing distribution to the Statnett R&D project pilot IEC 61850 digital substation.

1. Introduction – timing requirements in the power system
The power transmission system is increasingly dependent on accurate time-stamping of digitally sampled values used in protection and control. Power system uses of timing and associated accuracy requirements are summarized in figure 1. For a comprehensive overview of power sector timing issues, see references [NASPI2017] and [GSA2018].

The IEC 61850 requirement of microsecond accuracy with respect to UTC can be met by properly installed and characterized GNSS timing receivers [EURAMET2016] in combination with timing distribution using the IEEE 1588 PTP precision timing protocol on the substation process bus. However, GNSS signals for open civilian use are weak and also lack effective authentication mechanisms. GNSS timing receivers may therefore be vulnerable to interference from malicious or inadvertent radio noise (jamming) and susceptible to ‘spoofing’ with generated GNSS-signals containing misleading timing and navigation data [Shepard2012]. Malicious timing attacks or simply inadvertent timing errors may have adverse impact on monitoring and control applications [Almas2018]. Applications studied in [Almas2018] illustrate the role of precision timing as a valuable cyber-asset in power sector control systems. For critical applications timing accuracy requirements need to be complemented by requirements on availability and integrity.

KEYWORDS
UTC, traceability, secure timing, redundant timing, IEEE 1588 PTP, cesium clocks
2. COSECTIME: Generation of traceable atomic timing and distribution through optical networks

The COSECTIME (COordinated SECure TIME) project is funded by the Norwegian TSO Statnett. The goal is to demonstrate how synchronization requirements of power system applications may be met independent of GNSS. The project uses state-of-the-art fiber-optic time transfer techniques for traceable, secure and redundant synchronization. In full deployment (see figure 2), the transmission system operator (TSO) generates redundant semi-autonomous UTC-traceable atomic timescales and distributes timing through redundant fiber-optic networks also under TSO control.
3. Setup of pilot demonstration timing distribution to an IEC 61850 digital substation

The COSECTIME project pilot demonstration is integrated into another Statnett R&D project building and evaluating a pilot IEC 61850 Process Bus compliant digital substation. See [Hurzuk2019] for a description. The pilot demonstration setup is outlined in figure 3.

**Substation clocks**

Substation clocks (Meinberg M3000) were chosen because they handle multiple external reference inputs (GNSS, PPS, IRIG-B, 10 MHz, PTP), support a number of different timing distribution modules, and incorporate a multi-channel measurement system. See figure 4 for a sketch of the substation clock configuration. A multi-channel measurement system monitors the timing offset of available external references against the substation clock timescale. The reference selection algorithm chooses among external references based on availability and configured priority, with an additional option of excluding ‘unacceptable’ external sources with timing offsets outside a selectable threshold. The local rubidium oscillator (Rb) is steered to follow the substation clock timescale and may be used for extended holdover when no other acceptable external references are available. The substation clock timescale is distributed to the various output modules. All PTP-GM (Grandmaster) modules for the substation buses get timing from the substation clock timescale, but run separate CPUs and network stacks.

Redundant Statnett master timescales are generated by industrial cesium clocks (Microsemi 5071A) at separate locations. The accuracy and traceability of Statnett clocks with respect to UTC is maintained by time transfer to the timescale UTC(JV) generated by the Norwegian national timing laboratory at Justervesenet (JV). We have established continuously running clock comparisons via dedicated high-accuracy IEEE 1588-2019 PTP-WR (Precision Time Protocol; ‘White Rabbit’) fiber-optic links between Statnett and Justervesenet. PTP-WR links have been demonstrated to maintain high stability over more than 1000 km of optical transport networks [Dierikx2016], suitable for running direct sensitive comparisons of stable atomic clocks at separate geographic locations. Clock comparison data are the basis for occasional steering of Statnett cesium clocks. The cesium clocks have to be steered a few times per year to stay within a target of 100 ns offset from UTC. The required frequency of steering depends partly on the stability of the clock environment at Statnett (temperature, humidity and magnetic fields) and has been evaluated in the COSECTIME project. Fully deployed, Statnett will have autonomous control over timing sources and timing distribution to critical power system control and monitoring applications. The role of the national timing laboratory is to provide traceability of Statnett timescale(s) to UTC and a running indirect verification and supervision of Statnett timing. See [Śliwczyński2019] for a similar model implemented in the telecom sector.
Timing links
Timing links to the substation were established using IEEE 1588-2008 PTP (default profile). The PTP link to the digital substation is carried over a combination of coarse (CWDM) and dense wavelength division multiplexing (DWDM) optical transport networks. Optical-to-electrical-to-optical transponder cards in the DWDM system are used to convert between CWDM and DWDM optical channels. See figure 3 for details.

Measurements and data archiving
Multi-reference source measurement data from both substation clocks are logged every 12 s and automatically archived daily at a central data repository for off-line analysis. Additional measurements are performed using a high-resolution time-interval counter (Keysight 53230A).

4. Results and operational experiences from the pilot demonstration

Suitability of cesium clocks for timescale generation
Clocks (Microsemi 5071A standard performance) were initially calibrated at Justervesenet in a stable lab environment, with strictly controlled temperature and humidity. Clocks were also characterized in a climate chamber to determine the influence of temperature changes on the clock rate. Between 12 oC and 32 oC, cesium clock#2 showed a systematic rate change corresponding to -0.5 ns/day/K. Figure 5 left panel shows the time deviation of cesium clock#1 and #2, indicating that timing errors due to random clock noise should stay well within a target 100 ns deviation over 100 days.

At the end of characterization at Justervesenet, both clocks were nominally synchronized (frequency and phase) to UTC using the ‘rapid UTC’ product from BIPM [Petit2014]. Cesium clock#1 was deployed at clock site 1 and placed in a server rack with forced air (18 oC) convection cooling through the rack. Cesium clock#2 was eventually placed at the digital substation pilot to provide a redundant stable time reference.

The influence of the clock environment was evident for cesium clock#1. Through on-site calibration, we found that the clock had gained a systematic rate change of +4 ns/day compared to the calibration value in Justervesenet’s laboratory. This change is mostly due to a significantly lower operating temperature.

Cesium clock#2 deployed at the digital substation was evaluated by comparison to the substation clock GNSS timing (figure 6). Over 100 days, the average clock rate error corresponds to 0.2 ns/day with respect to the GNSS clock, and the long-term stability (> 10 days) is comparable to the stability measured in the lab environment.

In conclusion: Cesium clocks are suitable for stable timescale generation in an industrial environment, but to maintain timing within 100 ns of UTC, clocks need initial synchronization and sporadic steering based on repeated on-site calibration or running verification.
convert between CWDM and DWDM optical channels. Recently, WR links have been established using alien wavelength (i.e. without transponders) in the Statnett DWDM lab network, but not yet implemented in the production network. A similar alien wavelength link has been described by [Dierikx2016].

**Standard PTP links**

Currently operating links are between clock site 1 and the digital substation and between clock site 1 and Justervesenet. The links use the default profile IEEE 1588-2008 PTP. Clock comparison data of cesium clock #1 and cesium clock #2 through the PTP link (figure 3) is shown in figure 7. With the exception of a particular 200 ns dip of unknown cause, the PTP link itself does not contribute to the variation observed for , which is dominated by random timing noise of the cesium clocks.

The pilot link (figure 3) was found to have delay asymmetry resulting in a systematic offset of 340 ns for timing received at the substation clock. This asymmetry was calibrated using cesium clock #2 as a mobile time transfer reference. Such asymmetries may be compensated in the substation clock multi-reference source measurement system.

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**PTP-WR links**

High accuracy IEEE 1588 PTP-WR [IEEE2019] was initially intended to be used for the network timing links in the COSECTIME project. The inability of WR equipment to achieve stable timing lock for the link shown in figure 3 and a similar link set up between Statnett and JV is likely due to excess jitter in the optical-to-electrical-to-optical transponders used to
In conclusion: The established point-to-point links using standard IEEE 1588-2008 PTP are sufficiently stable for timing distribution to the digital substation. However, a sensitive comparison of cesium clocks may benefit from the high accuracy IEEE 1588 PTP-WR in combination with high-resolution time interval measurements.

Cesium clock failure
Cesium clock #1 located at remote clock site 1 failed after 482 days of continuous operation. While the clock controller reported fatal loss of lock on the cesium resonance, the clock continued operating on its internal crystal oscillator. In normal operation, the crystal oscillator is continuously disciplined to follow the long-term accuracy and stability of the cesium resonance.

A system for detection of cesium clock alarms had not been implemented, nor had a direct running link between clock site 1 and Justervesenet been established. However, PTP timing from cesium clock#1 was distributed to substation clock#1 and used as the selected synchronization source. Archived multi-reference data show the effect of the clock failure on substation clock timing (figure 8).

The clock failure could have been detected at several layers of a timing chain as depicted in figure 2: (1) By detecting ‘fatal error’ alarms raised by the clock itself; (2) By real time analysis of cesium clock comparison data, either with another clock at the same site and/or through high stability timing links to other sites with cesium clocks; (3) At the substation clock, the PTP timing from Cs#1 could be rapidly flagged ‘erroneous’ and deselected as the preferred sync source by a majority vote among the available external synchronization sources (figure 8). However, such a logic is not currently implemented in the source selection algorithm of the substation clocks.

Calibration
Calibration of link delay asymmetries were carried out using a cesium clock as a mobile timing reference. This is convenient and accurate on short (< 1 day) calibration campaigns. The calibration uncertainty is of magnitude 10 ns and will be evaluated during the COSECTIME project. However, for any country-wide deployment of network timing, using a mobile clock is labor-intensive and logistically challenging. Calibration of network delay asymmetries would benefit greatly if substations were equipped with properly calibrated GNSS timing reception chains (antenna/cable/lightning arrester/timing receiver) [EURAMET2016].

5. Discussion
The results presented above indicate that industrial cesium clocks in combination with fiber-optic timing distribution using IEEE 1588 PTP (standard and/or high accuracy ‘White Rabbit’) is an alternative to GNSS timing for power application sync requirements. The clear benefit of this approach is that GNSS-timing is only used as a secondary backup, thus eliminating adverse impacts of potential GNSS jamming or spoofing. However, deploying redundant cesium clock timescale systems and associated sync distribution networks comes with additional challenges: (1) Maintaining robust timescales, i.e. how to steer clocks and detect failing individual clocks and still be able to provide an accurate timescale; (2) Deploying a sync distribution network with 100s of user sites and calibrating network timing asymmetries; (3) Monitoring the overall integrity of the timing distribution chains, including anomaly detection. Such timing anomalies may be due to failing equipment or changes in the sync distribution network paths that affect timing asymmetries.

Disclaimer
Commercial products are identified for the sake of completeness. No particular endorsements are implied. Described apparent strengths or weaknesses may not be characteristic of current equipment versions.

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Summary

This paper reports on an experimental investigation that uses coarse or dense wavelength division multiplexing (CWDM, DWDM) for applications in high-speed traveling-wave protection. This paper documents the performance, opportunities, and pitfalls associated with this application and outlines practical strategies for the seamless integration of protection systems with the latest generation of optical transport network (OTN) technologies.

1. Introduction

Power system protection typically operates autonomously, with communications-based schemes historically reserved only to protect the most critical transmission assets. Communications bandwidth and the cost associated with providing it has for many decades forced power system protection engineers to economize on communications resources.

Communications-based protection scheme deployments started with analog pilot wire, which sent current transformer secondary signals over a span of several kilometers. Pilot wire schemes evolved rapidly, spanning ever-increasing distances. Power line carrier technology, microwave links, and eventually time-division multiplexing (TDM) channels, such as synchronous optical network (SONET) and synchronous digital hierarchy (SDH), came next. They enabled the deployment of full segregated digital phase differential schemes (ANSI Device #87), as illustrated in Figure 1.

The Internet-driven data deluge followed, forcing communications systems to carry ever-increasing amounts of packet-based network traffic supplied by Ethernet and multiprotocol label switching (MPLS). Packet-based networks opened new interoperability challenges while simultaneously creating new opportunities to improve the overall quality of service [1].

The latest generation of ultra-high-speed (UHS) transmission line protective relays has recently raised the bar by introducing time-domain protection elements, traveling-wave fault location, high-resolution event recording, time-coherent MHz-level sampling, and current traveling-wave-based differential protection (TW87 element).

Without diving into a discussion about whether a dedicated TW87 fiber-optic channel is economically justified, it is sufficient to note that the sustained data bandwidth consumed by continuously transmitting 6 analog measurements (3 voltages and 3 currents) sampled one million times per second is on the order of...
145 Mbps. Data are transported using a 1 Gbps Ethernet channel with small form-factor pluggable (SFP) transceivers, allowing the user to match the required transmission distance and control the associated light wavelength. As practicing engineers will immediately note, requesting a dedicated dark fiber channel for a single protection service is guaranteed to cause major interest in the communications department.

This paper (a shortened version of [2]) presents the results of a UHS protective relay test using a dedicated fiber-optic communications channel. The testing was conducted at the Pacific Gas and Electric (PG&E) High Performance Communications Technology Laboratory in San Ramon, California. The test was performed using the PG&E optical transport network (OTN) system, which carried the required relay payload with ease.

The paper also raises several questions about the design of future protection systems, revolving around the realization that modern fiber-optic communications systems have managed to exceed the communications bandwidth typically requested by present day protective relay designs by as much as 5 to 9 orders of magnitude.

### 2. Dedicated Communications Channel Requirements

A UHS transmission line relay TW87 communications link is a dedicated, private point-to-point fiber connection between two relays and has the following requirements:

- 1 Gbps Ethernet physical layer
- Industry-standard SFP module-based fiber interface
- Individual frame jitter that is below 25 ns
- Link asymmetry that is below 100 ns
- Low latency
- Constant link delay (no protected path switching)
- No third-party traffic

Travel time jitter and link asymmetry requirements are the most difficult specifications to meet but are essential for the UHS relays to maintain common time and synchronize individual samples down to the nanosecond level across hundreds of kilometers.

Synchronization could, in theory, be accomplished using two sources of time, supplied independently to the individual relays. Although simple, the independent clock approach does not satisfy a key requirement that UHS relay designers want to achieve, namely, that the relay protection functions be insensitive to external sources of time and any conceivable failure modes associated with those sources. To meet this requirement, relays rely on an internal time source (highly accurate, temperature-compensated crystal oscillator). External sources (when present) are strictly monitored, and if acceptable, are used to discipline the phase of the 1 MHz sampling clock.

When TW87 is enabled, a dedicated communications link allows the two UHS relays to form a strong synchronization bond. A ping-pong message exchange is used to continuously measure the fiber-optic link delay between the two relays. To maintain synchronization, it is essential that the link between the relays provide a constant transport delay.

While not a primary requirement, the TW87 scheme channel latency needs to be in line with the UHS relay operating speed because the excess channel latency directly affects the operating time of the TW87 element.

<table>
<thead>
<tr>
<th>Transport Technology</th>
<th>Acceptability</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single-mode fiber pair</td>
<td>Yes</td>
<td>Difficult to justify for sole use by protection</td>
</tr>
<tr>
<td>CWDM</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>DWDM</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>OTN</td>
<td>Yes</td>
<td></td>
</tr>
<tr>
<td>SONET / SDH</td>
<td>No</td>
<td>Jitter</td>
</tr>
<tr>
<td>Ethernet network</td>
<td>No</td>
<td>Jitter</td>
</tr>
<tr>
<td>MPLS</td>
<td>No</td>
<td>Jitter</td>
</tr>
<tr>
<td>Software-defined networking-based (SDN-based) Ethernet</td>
<td>Sometimes</td>
<td>Affected by device construction and network setup</td>
</tr>
</tbody>
</table>
Using the outlined point-to-point link requirements, a list of communications technologies that can be used to establish the link is shown in Table 1. Using a pair of single-mode fibers is the simplest solution. A pair of fibers is required because normally one fiber is used for data transmission and the other fiber is used for data reception.

The use of wavelength division multiplexing (WDM) is much more common in the industry. In WDM, tightly controlled wavelengths of light (colors) are used to transport multiple communications links over the same fiber. Simpler systems use coarse WDM (CWDM) with up to 16 channels available in the 1,310 nm and 1,550 nm bands. More advanced systems use dense WDM (DWDM) with 44 or 88 discrete channels allocated in the 1,550 nm band. This band has the lowest attenuation and leverages the availability of Erbium-doped fiber amplifiers (EDFAs), thus supporting long-distance transmission. Applications using any of the three intended technologies are shown in Figure 2.

OTN is the latest generation of communications technologies, intended primarily for metropolitan aggregation and long-distance core networks. OTN provides a transparent digital wrapper intended for the end-to-end transport of lower-speed network technologies, such as SONET, SDH, Carrier Ethernet, MPLS, storage area networks, and so on, and it is currently a preferred access method for large data centers.

SONET, SDH, Ethernet, and MPLS cannot currently be used to meet the TW87 link requirements. SDN can in some cases be configured to provide sufficiently low jitter, but this performance remains manufacturer-specific and design-dependent.

3. Optical Communications Network at PG&E

PG&E is an investor-owned electric utility company serving over 5.4 million electric and 4.3 million gas customers. Headquartered in San Francisco, California, PG&E serves a territory of over 70,000 square miles in northern and central California. In addition to its extensive electric and gas networks, PG&E also operates a large optical network linking virtually all major high-voltage substations in its territory. PG&E’s network uses high-quality single-mode fibers typically deployed along the high-voltage transmission line right of way using optical ground wire (OPGW) technology.

PG&E’s communications network uses state-of-the-art OTN technology [3], with 61 nodes already in service. Ten additional nodes are in the works at the northern edge of the service territory, promising full network coverage in the near future. PG&E’s utility neighbor to the north, Bonneville Power Administration (BPA), is in the process of commissioning a similar OTN system. Similarly, PG&E’s neighbor to the south, Southern California Edison, operates an extensive fiber-optic network with a long history of offering fiber-optic services on the open market.

4. OTN Technology Primer

OTN is a tightly coupled set of technologies aimed at providing transparent, multiservice transport for a wide variety of packet and TDM-based technologies. OTN scales well beyond 100 Gbps per transported tributary and includes a framework for efficient wavelength division control, reconfigurable optical add-drop multiplexing (ROADM), optical amplification, centralized network management, and all optical long-haul transport capabilities. OTN is highly configurable and works hand in hand with the latest generation of SDN.

As an optical transport technology, OTN should be seen as a large number of centrally managed point-to-point links that can be deployed at will. DWDM and the advanced modulation schemes in use today allow the OTN technology to approach the presently known limits of the capacity of single-mode fiber, as shown in Table 2.
The optical fiber capacities provided in Table 2 assume the use of DWDM with 88 or more individual wavelengths. Each wavelength is modulated using binary phase shift keying (BPSK), quadrature phase shift keying (QPSK), or quadrature amplitude modulation (QAM) with a constellation of 8, 16, or more symbols (8QAM, 16QAM). For modulation rates above 40 Gbps per wavelength, it is also customary to use polarization multiplexing (PM).

Use of multiple wavelengths provides guaranteed (physical) separation of traffic between different streams, while the high transmission speeds make it possible to transparently encapsulate legacy rates and services (such as MPLS or SONET/SDH). OTN transport has standardized the rates shown in Table 3 (applied per DWDM wavelength).

Rates are carefully selected to allow easy mapping of various legacy channels, for example, Gigabit Ethernet or OC-48 (2.48 Gbps) SONET services. Slightly larger data rates make it possible to transparently transfer channel timing while at the same time supporting frequency tolerance range and the clock jitter mask requirements of the legacy channel.

Although supporting lower rates (such as ODU0), OTN gets in the zone at 10 Gbps or above. For example, at those rates, the ODU2 10.037 Gbps channel can be used to multiplex together one Gigabit Ethernet LAN tributary, one OC-48 (2.48 Gbps) SONET channel, and 5 MPLS channels supplied using 1 Gbps Ethernet ports. All of these tributaries are transported “one bit at a time” (in a round robin fashion, sending one, two, or more bits from each channel, depending on the rate of the tributary). Actual rate management is more complex, with multiple options available to the network engineer, but it is important to note that fine granularity (bit by bit) of such multiplexing allows the subtended systems to maintain their time and frequency synchronization requirements.

OTN systems use forward error correction (FEC), which results in slightly higher rates by the time fully multiplexed electrical signals are delivered to their corresponding modulators and/or WDM channels. FEC provides an additional layer of robustness, allowing the optical transport specialist to monitor the bit error rates (BERs) for each wavelength and proactively adjust the system parameters before the errors become visible to the end customers.

The summary above barely scratches the surface of OTN network capabilities. For additional details, interested readers are directed to [3] and the easily accessible information on the Internet.

5. San Ramon Laboratory Test

To verify the PG&E network’s ability to transport the UHS relays’ TW87 messages, a live equipment test was conducted at the PG&E San Ramon Communications Systems Test Laboratory. Initial conversations among the engineers involved in the project indicated a high level of confidence on the side of the PG&E communications team, caution on the side of the PG&E protection team, and major reservations on the side of the relay design team.
The teams agreed to conduct two independent tests. The first test would use DWDM-capable SFPs plugged directly into the relays. The selected wavelength would then be brought directly into the PG&E OTN platform optical plane using the “alien wavelength” interface module. This approach guaranteed that the UHS relay would have direct access to the optical fiber for the given wavelength. The OTN system hardware used for the test is shown in Figure 3.

An alien wavelength card is normally used when the traffic from a neighboring carrier needs to traverse the network without interference. Allocating an entire alien wavelength to a single relay channel in effect means committing a resource with a 100+ Gbps theoretical capacity. In the PG&E network case, resource allocation is slightly less critical because the individual wavelengths are typically modulated at 10 Gbps. The alien wavelength approach still provides much greater efficiency than using a dedicated dark fiber pair (15+ Terabit resource).

A detailed diagram showing the alien wavelength test setup is shown in Figure 4.

A second test involved the use of ODU2 multiplexing. In this test, a 1 Gbps link used by the UHS relays becomes a simple tributary to the ODU2 (10 Gbps) stream, with additional services (including PG&E SONET and MPLS networks) being multiplexed in at the same time. The OTN multiplexing approach provides the best bandwidth utilization, with a 1 Gbps link being provisioned to consume a 1 Gbps resource.

A detailed diagram showing the ODU2 test setup is provided in Figure 5. The results for the two tests are shown in Table 4.
As the results show, the UHS relay link was successfully established in both cases. The alien wavelength test provided the measurement of the actual fiber length connecting the two OTN systems in the lab. The jitter measurement shows that there was no detectable jitter (<8 ns). The ODU2 multiplexing test shows additional latency caused by the FEC system. This additional latency was expected and is fully controlled by the OTN network engineer.

Available settings and the associated end-to-end delays are shown in Table 5.

Table 4 OTN Test Results

<table>
<thead>
<tr>
<th>Test</th>
<th>Error Correction</th>
<th>Measured Latency (µs)</th>
<th>Measured Jitter (ns)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alien wavelength</td>
<td>None</td>
<td>1.6</td>
<td>&lt;8</td>
</tr>
<tr>
<td>ODU2 tributary</td>
<td>EFEC</td>
<td>60.8</td>
<td>&lt;8</td>
</tr>
</tbody>
</table>

Table 5 FEC and Associated Transport Latency

<table>
<thead>
<tr>
<th>Line-Side FEC</th>
<th>Tributary Rate (GHz)</th>
<th>Line Rate (GHz)</th>
<th>Latency (µs)</th>
</tr>
</thead>
<tbody>
<tr>
<td>None</td>
<td>1.25</td>
<td>10.709</td>
<td>17</td>
</tr>
<tr>
<td>RS FEC</td>
<td>1.25</td>
<td>10.709</td>
<td>23.5</td>
</tr>
<tr>
<td>EFEC</td>
<td>1.25</td>
<td>10.709</td>
<td>59</td>
</tr>
<tr>
<td>EFEC2</td>
<td>1.25</td>
<td>10.709</td>
<td>157</td>
</tr>
</tbody>
</table>

Figure 5. ODU2 multiplexing test setup.
The exact meaning of the various options (RS FES, EFEC, and so on) is beyond the scope of this paper, but can be found in [3]. What matters is the close agreement between the expected and the measured results of the test.

6. Relay Design Opportunities

As explained in the introduction and clearly demonstrated during the test, modern utility communications systems are more than capable of satisfying the protection system data communications needs.

Faced with the continuously evolving communications capabilities, protection device designers are challenged to use the latest Ethernet protocols while at the same time having to support the legacy 64 kbps synchronous interfaces.

Ethernet communications are especially convenient in multiterminal applications in which a single relay needs to exchange data with multiple peers. In order to support mission-critical protection applications, an Ethernet network must be purposefully engineered and capable of providing guaranteed quality of service. General-purpose Ethernet networks are inadequate for this purpose. Instead, fully configured networks must be used, with key technologies including SDN, Ethernet pipe transport over SONET, and time-sensitive networking (TSN).

Packet-based networks are typically associated with queuing delays and an inability to control transport delay variations. As long as the total latency is low enough to meet the protection system requirements, these problems can be solved by adding a network-based time-synchronization service, such as Precision Time Protocol (PTP, also known as IEEE 1588) or one of its profiles (IEC 61850-9-3 or IEEE C37.238).

Ethernet-based protection schemes work as long as the Ethernet network can guarantee that the same time-synchronization signal is delivered to all devices that can communicate with each other, meaning time synchronization and communications should always work in tandem. To meet this goal, time synchronization must become a guaranteed core network service. Traceability of the network time source to Coordinated Universal Time (UTC) is less important, provided the same time is being distributed to all communicating devices.

The exact method for distributing time throughout the network core is less important. It can be proprietary or standards-based as long as the time distribution is reliable and unconditionally cybersecure. One such system based on SONET transport is described in [4]. SONET and SDH are especially convenient for this use because the system cannot operate without establishing a strict synchronous connection with the neighboring nodes.

The system described in [4] is a great example of the time distribution service that demonstrates the level of performance that needs to be provided by any network core. The exact implementation is less important but applies equally well to the OTN network core and the edge networks emanating from that core (e.g., Ethernet, MPLS).

When considering OTN and maximum capacity limits for a single-mode optical fiber, it is important to note that power system protection and control applications do not generate enough traffic to fully load or justify the OTN system. Present day protection and control needs are easily met with a single OTN wavelength. Remaining OTN capacity can be leased or used for other purposes.

7. Conclusion

While not every electric power utility can be expected to switch to OTN technology in the near future, the PG&E and BPA examples can be seen as forerunners of things to come over the next decade. The authors are very excited about the potential of OTN technology and future optical technology advancements.

Relay design engineers are finally finding themselves in an environment with virtually no bandwidth constraints, making it possible to exchange the optimal amount of data required for a given protection application. This means much greater penetration of differential protection schemes, with virtually all key resources protected using some type of optical communications.

8. Acknowledgements

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9. Bibliography


Abstract
The changing resource mix of the bulk power system has necessitated investigation into viable alternate control schemes for use during operation of the system. In literature, the major theme of these alternate schemes has however been on ensuring that inverter based resources conform to the operational norms and limits that are presently enforced. In this paper, a constant frequency operational scheme previously proposed by the authors has been further developed to ascertain operational constraints. The paper looks at the applicability of this constant frequency control paradigm to both inverters behaving as voltage sources and inverters behaving as current sources. Additionally, the impact of this fast control scheme on the rate of change of speed on few remaining synchronous machines has also been investigated. To ensure both short term and long term power sharing, a modified automatic generation control scheme has been implemented and its satisfactory operation has been shown.

I. Introduction
The aim of this work is to provide an insight into the required performance characteristics expected from converter interfaced sources in order to operate an all converter bulk power system in a reliable and stable manner. This goal is however achieved by first designing a high level generic control scheme for each converter resource, and then evaluating the performance and suitability of this scheme for the bulk power system. It can be argued that the ideal process should be the other way around in that, based upon the requirements of the bulk power system, the control scheme must be designed, and then the validation of the operational behavior must be conducted. However, the changing paradigm of the power system (all synchronous machines to all converters), makes this task difficult, as it is presently hard to envision the exact requirements of an all converter system. Thus, by starting with the design of a control scheme, an ‘initial guess’ is made at the way the converters can be controlled, and its suitability from the bulk power system point of view can be evaluated. Based upon the evaluation, the needs of the power system with all converters can be gleaned to result in an improvement of the control system design.

There are many research groups around the world working on development of converter control solutions for an all converter network. Some articles in literature, among others, are references [1]–[13]. Research has been conducted on the comparison of region of stability provided by various control schemes such as virtual oscillator control, virtual synchronous machines, and grid forming droop control. Additionally, the impact of presence of numerous converter sources in a large power system has been investigated along with the consideration of stochastic nature of solar and wind sources. However, all researched control schemes have two main themes, (1) the operation of the bulk power system to a generation or load event is assumed to require compliance with traditional frequency droop control wherein, upon the occurrence of a disturbance, the aim is to allow frequency to settle to an off-nominal value, and (2) the energy burden required from the source behind the converter is not studied.

In a system with conventional synchronous machines, due to Newton’s laws of physics, frequency has a natural relationship with the speed of the rotating machine and hence the mismatch between generation and load. Additionally, the acceptable region of frequency deviation from nominal is governed by various system factors, chief

KEYWORDS
All inverter, constant frequency operation, RoCoF

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was shown that in an all converter system operating at constant frequency, sharing of power among converters in the aftermath of a disturbance was still possible with the use of an angle droop control scheme.

While, an all converter system is still in the distant future for the power system, there are certain systems around the world that can soon reach 80% converters for few hours of the day. In such a system, with synchronous machines still on-line, the juxtaposition of fast converter controls along with slower synchronous machine control can be a cause for concern, and is to be analyzed. Thus, with that criterion, the constant frequency converter control scheme developed previously [15] will be used in this paper to answer the following questions:

1) Can converter resource continue to be controlled as strict current sources, or would they have to be controlled as voltage sources?
2) For a large generation loss event, with constant frequency control, can power be shared in the short term among all participating converter resources?
3) Over the long term, can the flows on the tie line interfaces between areas be restored to the pre-disturbance value?
4) If there are few synchronous machines remaining on the system, will the fast constant frequency control of the converters have an adverse impact on the machines?

Before we take a deep dive into the case studies, first, the constant frequency control scheme is revisited. A modularized version of inverter control models were used in this analysis, while making use of existing converter models in software. This allows for easy transference of the analysis to any other power system.

The subsequent sections will discuss the modularized versions of the mathematical models used in the analysis, and the results of the analysis will be presented.

2. Modularized set up of models

A modularized setup makes it easy to try out different control structures, while also making use of existing converter models. Two modularized versions of the control structure were developed for the purpose of this analysis. A broad overview of these modularized setups is shown in Fig. 1 and Fig. 2. In both modular
structures, the REEC_A generic model [16] is used as the electrical controller for the converter energy sources. The performance of this model and its accuracy for use in representation of outer loop controls of converter energy resources has been widely tested and benchmarked [17], [18]. Additionally, this model is available as a library model in all major commercial positive sequence transient simulation software (GE-PSLFTM, Siemens PSS®E, Powertech Labs DSAToolsTM, PowerWorld Simulator, and DlgSILENT PowerFactory) and thus, the concepts of the paper can be easily extended for studies on any large power system. The electrical controller model REEC_A has been used in local voltage control mode, with Q priority, and no momentary cessation. The block diagram and associated equations of this model are available in public reference documents such as [17].

A. Converter/Network Interface Model

In the first modular structure Fig. 1, the converter interface to the network is modeled as a current source using the REEC_A model. The accuracy of this model has also been extensively benchmarked. Although converters used for renewable energy applications are inherently voltage sources, a strict control of current is maintained by following the angle of the grid. Thus, to the grid, the converter resource takes the form of a current source and hence, the positive sequence model (REEC_A) is represented as a current source. There are of course limiting grid conditions (both from a numerical simulation perspective and in reality) under which this current source representation would not be valid (low short circuit as an example), and instead, a voltage source representation of the converter would be required. The block diagram and associated equations of this model are also available in public reference documents such as [17]. Due to this, the diagram and equations of these models are not repeated here in this paper and an interested reader is encouraged to access this reference for more information.

However, presently, none of the previously mentioned major commercial simulation platforms have a voltage source representation of the converter as a library model. Specific user defined models containing voltage source representations of the converters pertaining to individual inverter plants, do exist and are used in the industry. However, these models contain confidential and proprietary control algorithms which are specific to the inverter manufacturer and plant developer. Thus, when conducting a futuristic long term planning study, these models, while could be useful, are not suited for the purpose. Recognizing this limitation, through the Western Electricity Coordinating Council (WECC) Modeling and Validation Working Group (MVWG), beta models of voltage source representation of converters are being implemented in the simulation software [19]. However, it
would be sometime before which these models become mainstream library models.

Additionally, as the percentage of inverters continue to increase in the bulk power system, there will be a need to deviate from the control strategy of strictly controlling current as in the immediate aftermath of a disturbance, the grid requires an injection of current in order to prevent a large decrease in voltage levels. One alternate to this strict current control strategy is to use a constant voltage control strategy [20] as it would allow for rapid injection of current in the immediate aftermath of a disturbance, subject to current limits and being in synchronism with the grid. However, due to the structure of positive sequence simulations, the intricacies of these control schemes cannot be represented in detail [18]. On the other hand, detailed point-on-wave simulations are computationally too expensive, and difficult to set up for bulk power system analysis. Thus, the middle ground for bulk power system is to develop positive sequence generic converter models that can capture the trend of these detail control schemes without sacrificing on the computational accuracy required for bulk power system analysis.

It can be argued that as real time simulators are progressively becoming more powerful, the requirement of model reduction for computational accuracy may be unwarranted. However, these real time simulators are bulky and not readily flexible in order to conduct planning studies such N-1, N-1-1, and N-2 outage events on large systems that may have thousands of elements and tens of thousands of combinations. When a utility conducts generator interconnection studies in a planning realm, where there may be no information available regarding which manufacturers’ inverters would be used in a particular plant, or when one utility wants to study the impact on its system the behavior of its neighboring utility, the detailed data required to harness the advantage of real time simulators may not be readily available or manageable. In such a scenario, while the actual running of a case may be computationally efficient, the adjoining factors such as setting up of the case, ensuring a steady initial condition, maintaining the required data files, and so on, may in itself be a huge burden for large systems. Thus, having a computationally efficient model and network framework with minimal additional data burden is useful as it would help in screening out multiple locations for which real time simulations may not have to be carried out. At the same time, presently there are positive sequence real time simulators which are used by operators in the control room to run studies in close to real time using a mix of SCADA data and the planning base cases. The converter model used in this paper can be equally applied even in such a scenario and provide an operator with an immediate insight into the possibility of occurrence of stability issues that would not have been captured by the previous models. Details regarding the possible oscillatory instability that may occur is discussed in [21]. It must be noted that use of generic models and parameters can only provide a glimpse into the trend of response that would be available from inverter based resources. This trend is however often sufficient for making bulk power system planning decisions.

The user defined voltage source converter model used in this paper [15], [22] is a representative example of this middle ground. The model is capable of representing the faster phase locked loop and inner current control dynamics that are of crucial importance while analyzing the behavior of converter interfaced generation in low short circuit areas. Additionally, due to the voltage source interface, it is also able to mimic a constant voltage control in the immediate aftermath of the disturbance. The main drawback of the constant voltage control scheme is that there is no explicit way of limiting the magnitude of current injected, as this is now dictated by the Thévenin impedance of the grid, as seen by the converter. As the voltage is being controlled, in order to ensure that current does not violate its limits, in this model, an inner current control loop has been included. Thus, this converter model can be assumed to be representative of a hybrid control scheme which has the qualities of both constant current control and constant voltage control, each acting on their own individual time scales to prevent instability of the control loops. The block diagram of this converter model is shown in Fig. 3.

However, it must be emphasized here that the focus of this paper is not to show the development of this converter model. Performance validation of this converter model has been carried out previously by the authors, and has been documented in [15], [22]. The focus of this paper, as laid out by the questions in the introduction, is to however ascertain the need, understand, and compare
the performance of the bulk power system with a large presence of inverters to these various control schemes. This user defined voltage source converter has been structured in a way so as to accept commands from the existing generic REEC_A electrical controller model, and can thus be connected as shown in Fig. 2.

B. Active Power Controller Model
As another aim of this paper is to assess the strategies of sharing of power amongst converter interfaced plants over both the short term and long term, a user defined active power controller model was developed. The structure of this user defined active power controller model is as shown in Fig. 4 while the equations of the model are described in (1)-(4). All quantities in this controller are in per unit on a MW value base which can be lower than the MVA rating of the converter.

\[
\frac{ds_1}{dt} = \frac{1}{T_1} \times \left( \frac{f - 1.0}{R} - s_1 \right)
\]

(1)

\[
\frac{ds_2}{dt} = K_{ferr} \times (f - 1.0 - \delta_{ref})
\]

(2)

\[
P_{droop} = K_{serr} \times (s_2 - \delta_{ref})
\]

(3)

\[
P_{cmd} = P_{init} + P_{agc} - P_{fdroop} - P_{sdroop}
\]

(4)

Through this module, efficacy of power sharing using conventional frequency droop control schemes can be compared with the efficacy of power sharing using the constant frequency angle droop control scheme that has been previously proposed by the authors [15]. With the constant frequency control scheme, a valid question arises as to whether power can be shared across large control areas. In the present power system, the magnitude of deviation of frequency from its nominal value plays a huge role in secondary frequency control to ensure that the generators in the area impacted by the disturbance, are largely responsible for picking up the burden of the disturbance. However, if a move is made to constant frequency, then can this operational status quo still be maintained?

Thus, in order to assess the ability of the constant frequency control scheme to control the power transfer between balancing areas, the ‘Tie-line deviation’ control loop was incorporated on a system level, and each converter resource received a signal (P^agc) to mimic the operation of a simple automatic generation control loop.
The positive sequence simulations were carried out in the large scale grid simulation program GE-PSLF™ [25]. This system has a total generation of 69 GW, and a total load of 67 GW/19 Gvar. Five separate cases were setup as defined,

1) **Case 1:** All 433 energy sources were modeled as conventional synchronous machines with a round rotor generator model (GENROU), a simple governor model (TGOV1) and a simple static excitation system model (SEXS).

2) **Case 2:** 417 energy sources were modeled as converter interfaced generation with the voltage source converter interface model, and the constant frequency control mode enabled. The remaining 16 energy sources, had an MVA greater than 500 MVA, and were represented as conventional synchronous machines, with the same type of models as in Case 1.

3) **Case 3:** 417 energy sources were modeled as converter interfaced generation with the existing current source converter interface model, but with the constant frequency control model enabled. The remaining 16 energy sources, had an MVA greater than 500 MVA, and were represented as conventional synchronous machines, with the same type of models as in Case 1.

4) **Case 4:** 417 energy sources were modeled as converter interfaced generation with the voltage source converter interface model, but with the constant frequency control model disabled. Only frequency droop control was enabled. The remaining 16 energy sources, had an MVA greater than 500 MVA, and were represented as conventional synchronous machines, with the same type of models as in Case 1.

5) **Case 5:** 417 energy sources were modeled as converter interfaced generation with the existing current source converter interface model, but with the constant frequency control model disabled. Only frequency droop control was enabled. The remaining 16 energy sources, had an MVA greater than 500 MVA, and were represented as conventional synchronous machines, with the same type of models as in Case 1.

One ‘Tie-line deviation’ block was placed in each area of the system, and its internal algorithm can be generally described as:

1) Once every 2 seconds evaluate the total tie line power mismatch of the area. This 2 second delay in measurement of tie line power mimics transport delay in telemetered measurements as they arrive at the central controller.

2) Compare the mismatch with a tolerance level,
   a) If the mismatch is below the tolerance level – do nothing.
   b) Else, integrate the difference through a PI controller to obtain a value of power that has to be raised/lowered in the area.

3) Once every 3 seconds, and through a further first order time constant of 1.0s, the value of power evaluated in step 2b is sent as $P'_{agc}$ to the active power controller of every converter resource in the area.

It must be mentioned here that in both modular converter interface representations, the dynamics of the dc bus and the source behind the dc bus have been ignored. Additionally, it has been assumed that the dc bus is stiff and/or the dynamics of the controller controlling the dc bus voltage is fast enough to cater to the demands of the grid side inverter controllers. While the dynamics of the sources and the dc bus are ignored, it must be underlined here that it is assumed that the sources have energy headroom/reserves available to meet the generation outage scenarios considered. The sources dynamics and possible constraints involved in the delivery of this additional reserve (such as pitch controllers or drive train dynamics of wind turbines, or state of charge control of batteries) are ignored in this study. This is not because they are not important or relevant, but because they are out of scope for the specific aspect of this paper which focuses on the grid side inverter interface.

The next section discusses results from implementation of both the modular converter structures on a 2000 bus Synthetic Texas system.

### 3. Demonstrating simulation results

To help address the questions raised in the introduction, a 433 machine 2000 bus system has been used [23], [24].
For Case 4 and Case 5, where the converters were only enabled with frequency droop response (with the same value of droop gain and headroom as the corresponding synchronous machine model used in Case 1), the final settling value of the frequency is the same as in the all synchronous case. These two cases are provided as a reference intermediate case to highlight the additional capabilities that can be extracted from converters. It should be noted that converters can have a smaller droop percentage (say 2% droop instead of 6%), which would result in a higher settling off-nominal frequency, but sensitivity to droop gain is not the objective of this work. This kind of sensitivity analysis is discussed in detail in [28]–[30].

In Case 2 and Case 3, where the converters were also enabled with the constant frequency control scheme, it can be seen that the electrical frequency is satisfactorily brought back to the nominal value of 60.0 Hz, within few seconds of the disturbance. Additionally, even with the presence of the large synchronous machines, the system frequency does not show any major oscillations that could be a cause of concern. This is however highly influenced by the value of the control gains used in both the converter and synchronous machine controls. But, in Case 1 as expected, there is a presence of inter area oscillatory modes. While these modes are not visible in the system frequency plot, they can be seen in the plot of each area’s frequency, as shown in Fig. 6.

The answers to the questions raised in the introduction can be obtained by observing the response of the system to a generation loss event. The two largest generators in this system have approximately 1.2 GW of generation each. To evaluate the behavior of the system, both these generators were tripped in a sequential manner at t = 10s and 25s. Since in all five cases, synchronous machines are still present in the system, the electrical frequency of the system still holds significance.

**A. Impact on overall system frequency**

The average electrical frequency across the entire system (average of electrical frequency evaluated at every bus in the system) is shown in Fig. 5. It can be seen that with all synchronous machines, the frequency response graph follows the well-known trace. In the actual Texas power system, the set point for under frequency load shedding is 59.3 Hz and has remained at that value since 2012 [27]. Additionally, the nadir of frequency (around 59.7 Hz) is also approximately equivalent to the nadir observed in studies shown in [27] for a generation trip of this magnitude.

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The individual area frequencies for Case 2 is shown in Fig. 7 for the duration around the first disturbance (i.e. 10s). Due to the fast action of the converters, there are minimal inter area oscillations in frequency range that is common in an all synchronous machine system. This is despite the presence of the fast phase locked loop and inner current control loop controls in the converter model. An interesting observation from Fig. 7 is that the area where most of the 16 synchronous machines are
system electrical frequency in the immediate aftermath of the first disturbance (the few seconds around 10s) is shown in Fig. 8

From the plot, the rate of change of frequency for each case evaluated 500ms after the disturbance is tabulated in Table I. While it is expected that with large presence of converters the rate of change of frequency will be steeper, the rate of change of system electrical frequency only shows one side of the picture. Even in an all synchronous system, as seen in Fig. 6, the rate of change of frequency is different in different areas of the system, and the electrical distance of a generator to the disturbance location also plays a role. In Case 1, for the same generation loss event, the rate of change of frequency at individual generator terminals was evaluated 500ms after the disturbance, and the generators with absolute value of rate of change greater than 0.15 Hz/s are tabulated in Table II. It is interesting to note that although the generation loss event was in Area 5, the present is readily observable as the frequency in this area has a slower rate of change of frequency (gray colored line in the plot).

**B. Impact on rate of change of frequency**

While the plots with the large presence of converters show a stable response, in all four of them, the rate of change of frequency is much steeper than the all synchronous machine case, while the nadir is higher. The higher nadir is attributed to the smaller time constants that are present in the frequency control path of the converter model, than the corresponding time constants in the governor and machine models. This allows for fast injection of energy from the converters into the power system. But, with the chosen values of control gains, this injection of energy from the converters is not fast enough to prevent a steep rate of change of frequency. This steep rate of change of frequency could be a cause of concern for the remaining 16 synchronous machines [31], [32]. In order to observe the rate of change of frequency better, the plot of the system electrical frequency in the immediate aftermath of the first disturbance (the few seconds around 10s) is shown in Fig. 8

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The largest rate of change is observable in the adjoining areas of 2 and 8. Geographically, the 8 areas in the system are approximately spread out as shown in Fig. 9, with the white lines denoting weaker portions of the network. The demarcation of areas is by no means precise, and it is a very high level approximation. However, it shows that generators in Area 2 and 8, especially if they are at the edge of the areas, can easily be electrically close to the event bus in Area 5. With the presence of converters, the rate of change of frequency at the 16 synchronous machines terminals is tabulated in Table III for Case 2 and Case 4. In Case 2, with the constant frequency operation of the converters, the rate of change of frequency at the terminals of the generators in area 7 have increased in comparison to their rate of change of frequency in an all synchronous machine setup. However, the rate of change at the terminals of the generators in area 8 have decreased when compared to the corresponding values (Table II) in an all synchronous machine system. In Case 4, with the converters operating only on conventional frequency droop control, the rate of change of frequency at the generator terminals has increased in comparison to the all synchronous machine case. The difference in the rate of change of frequency between Cases 2 and 4 can be attributed to the contribution from the converters in the other areas. As an example, the total active power output from the converters in Area 5 for Cases 2 and 4 (excluding the two generation sources that were tripped), is shown in Fig. 10. The near instantaneous spike in the active power response is an artifact of positive sequence numerical simulations wherein the source differential equations and network algebraic equations are solved sequentially and not simultaneously. Due to this, and a Thévenin representation of a voltage source, a spike in current output occurs at the instant of disturbance. In Case 2, due to the constant frequency control, the converters in Area 5 inject more energy into the system during the first 500ms. A similar behavior would occur in Areas 7 and 8 thereby, arresting the frequency decline at the terminals of the machines. It goes without saying that the injection of this additional energy is subject to conditions of a stiff dc bus and availability of energy.

<table>
<thead>
<tr>
<th>Case</th>
<th>Frequency (Hz) at 10s</th>
<th>Frequency (Hz) at 10.5s</th>
<th>Approximate rate of change (Hz/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>60.0</td>
<td>59.962</td>
<td>$\frac{59.962-60.0}{0.5} = -0.076$</td>
</tr>
<tr>
<td>2</td>
<td>60.0</td>
<td>59.94</td>
<td>$\frac{59.94-60.0}{0.5} = -0.12$</td>
</tr>
<tr>
<td>3</td>
<td>60.0</td>
<td>59.94</td>
<td>$\frac{59.94-60.0}{0.5} = -0.12$</td>
</tr>
<tr>
<td>4</td>
<td>60.0</td>
<td>59.898</td>
<td>$\frac{59.898-60.0}{0.5} = -0.204$</td>
</tr>
<tr>
<td>5</td>
<td>60.0</td>
<td>59.898</td>
<td>$\frac{59.898-60.0}{0.5} = -0.204$</td>
</tr>
</tbody>
</table>
from the source behind the inverter. Representation of the dynamics of these loops is a topic that will be pursued in the future.

TABLE II: Generators with rate of change of frequency greater than 0.15Hz/s in Case 1

<table>
<thead>
<tr>
<th>Bus number</th>
<th>Area number</th>
<th>Approximate rate of change (Hz/s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2115</td>
<td>2</td>
<td>-0.1525</td>
</tr>
<tr>
<td>2117</td>
<td>2</td>
<td>-0.1536</td>
</tr>
<tr>
<td>2118</td>
<td>2</td>
<td>-0.1546</td>
</tr>
<tr>
<td>2119</td>
<td>2</td>
<td>-0.1502</td>
</tr>
<tr>
<td>2120</td>
<td>2</td>
<td>-0.1541</td>
</tr>
<tr>
<td>8129</td>
<td>8</td>
<td>-0.1524</td>
</tr>
<tr>
<td>8130</td>
<td>8</td>
<td>-0.1560</td>
</tr>
<tr>
<td>8131</td>
<td>8</td>
<td>-0.1529</td>
</tr>
</tbody>
</table>

C. Impact of voltage versus current source interface

However, a question that then arises is whether this behavior is strictly due to the voltage source interface of the converter? A converter which is controlled as a pure voltage source (known as grid forming converters in some literature), is said to be able to inject energy into the network without delay upon the occurrence of a disturbance. It has been postulated in literature that this rapid injection of energy from a voltage source converter (subject to the availability of energy from the dc bus/source behind the inverter) can take the place of conventional inertial energy to help arrest the frequency decline as this rapid injection of energy is not possible.

Fig. 9: Approximate geographic split of substations in the system

TABLE III: Rate of change of frequency at the remaining 16 generators for Cases 2 and 4

<table>
<thead>
<tr>
<th>Bus number</th>
<th>Area number</th>
<th>Approximate rate of change (Hz/s) for Case 2</th>
<th>Approximate rate of change (Hz/s) for Case 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>7098</td>
<td>7</td>
<td>-0.1624</td>
<td>-0.1994</td>
</tr>
<tr>
<td>7099</td>
<td>7</td>
<td>-0.1624</td>
<td>-0.2112</td>
</tr>
<tr>
<td>7208</td>
<td>7</td>
<td>-0.1655</td>
<td>-0.2111</td>
</tr>
<tr>
<td>7209</td>
<td>7</td>
<td>-0.1648</td>
<td>-0.2109</td>
</tr>
<tr>
<td>7335</td>
<td>7</td>
<td>-0.1648</td>
<td>-0.2109</td>
</tr>
<tr>
<td>7353</td>
<td>7</td>
<td>-0.1679</td>
<td>-0.2124</td>
</tr>
<tr>
<td>7354</td>
<td>7</td>
<td>-0.1665</td>
<td>-0.2118</td>
</tr>
<tr>
<td>7355</td>
<td>7</td>
<td>-0.1665</td>
<td>-0.2118</td>
</tr>
<tr>
<td>7356</td>
<td>7</td>
<td>-0.1663</td>
<td>-0.2117</td>
</tr>
<tr>
<td>7389</td>
<td>7</td>
<td>-0.1593</td>
<td>-0.2102</td>
</tr>
<tr>
<td>7400</td>
<td>7</td>
<td>-0.1626</td>
<td>-0.2104</td>
</tr>
<tr>
<td>8071</td>
<td>8</td>
<td>-0.1402</td>
<td>-0.2312</td>
</tr>
<tr>
<td>8088</td>
<td>8</td>
<td>-0.1358</td>
<td>-0.2211</td>
</tr>
<tr>
<td>8129</td>
<td>8</td>
<td>-0.1357</td>
<td>-0.2303</td>
</tr>
<tr>
<td>8130</td>
<td>8</td>
<td>-0.1430</td>
<td>-0.2377</td>
</tr>
<tr>
<td>8131</td>
<td>8</td>
<td>-0.1356</td>
<td>-0.2301</td>
</tr>
</tbody>
</table>
In the real Texas power system, to plan for frequency response reserves, a loss of 2750 MW of generation, with a credit of 1209 MW of fast acting load response, is the benchmark event for analysis [27]. These numbers align with the net generation loss event that has been analyzed in this scenario. It is thus worthwhile to check if the same trend of rate of change of frequency observed above, holds if both the generators were tripped at the same time in this scenario. Table IV tabulates the rate of change of frequency at the terminals of the 16 generator machines across all 5 cases with simultaneous trip of two 1.2 GW generators.

<table>
<thead>
<tr>
<th>Bus number</th>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
<th>Case 4</th>
<th>Case 5</th>
</tr>
</thead>
<tbody>
<tr>
<td>7098</td>
<td>-0.0232</td>
<td>-0.2846</td>
<td>-0.3129</td>
<td>-0.3578</td>
<td>-0.3766</td>
</tr>
<tr>
<td>7099</td>
<td>-0.0366</td>
<td>-0.2915</td>
<td>-0.3168</td>
<td>-0.3890</td>
<td>-0.4062</td>
</tr>
<tr>
<td>7208</td>
<td>-0.0279</td>
<td>-0.2951</td>
<td>-0.3205</td>
<td>-0.3863</td>
<td>-0.4040</td>
</tr>
<tr>
<td>7209</td>
<td>-0.0284</td>
<td>-0.2942</td>
<td>-0.3192</td>
<td>-0.3864</td>
<td>-0.4038</td>
</tr>
<tr>
<td>7335</td>
<td>-0.0309</td>
<td>-0.2933</td>
<td>-0.3177</td>
<td>-0.3867</td>
<td>-0.4037</td>
</tr>
<tr>
<td>7353</td>
<td>-0.0282</td>
<td>-0.2989</td>
<td>-0.3249</td>
<td>-0.3882</td>
<td>-0.4062</td>
</tr>
<tr>
<td>7354</td>
<td>-0.0291</td>
<td>-0.2968</td>
<td>-0.3222</td>
<td>-0.3877</td>
<td>-0.4053</td>
</tr>
<tr>
<td>7355</td>
<td>-0.0291</td>
<td>-0.2968</td>
<td>-0.3222</td>
<td>-0.3877</td>
<td>-0.4053</td>
</tr>
<tr>
<td>7356</td>
<td>-0.0292</td>
<td>-0.2966</td>
<td>-0.3218</td>
<td>-0.3878</td>
<td>-0.4052</td>
</tr>
<tr>
<td>7389</td>
<td>-0.0444</td>
<td>-0.2873</td>
<td>-0.3082</td>
<td>-0.3879</td>
<td>-0.4022</td>
</tr>
<tr>
<td>7400</td>
<td>-0.0310</td>
<td>-0.2913</td>
<td>-0.3149</td>
<td>-0.3865</td>
<td>-0.4029</td>
</tr>
<tr>
<td>8071</td>
<td>-0.2497</td>
<td>-0.2786</td>
<td>-0.2685</td>
<td>-0.4621</td>
<td>-0.4521</td>
</tr>
<tr>
<td>8088</td>
<td>-0.1997</td>
<td>-0.2659</td>
<td>-0.2601</td>
<td>-0.4368</td>
<td>-0.4319</td>
</tr>
<tr>
<td>8129</td>
<td>-0.3078</td>
<td>-0.2748</td>
<td>-0.2649</td>
<td>-0.4663</td>
<td>-0.4558</td>
</tr>
<tr>
<td>8130</td>
<td>-0.3147</td>
<td>-0.2882</td>
<td>-0.2810</td>
<td>-0.4804</td>
<td>-0.4716</td>
</tr>
<tr>
<td>8131</td>
<td>-0.3091</td>
<td>-0.2748</td>
<td>-0.2656</td>
<td>-0.4665</td>
<td>-0.4566</td>
</tr>
</tbody>
</table>

Fig. 10: Total active power from Area 5, in the immediate aftermath of a generation trip, when obtained from constant frequency control compared with conventional frequency droop control from traditional current source controlled inverters [8], [9]. In order to test this hypothesis, Fig. 11 shows the total active power in Area 5 for Cases 2 and 3 (again excluding the two generation sources that were tripped).

Both Cases 2 and 3 have the constant frequency control mode enabled, but case 2 uses a voltage source interface converter while case 3 uses the present state of the art current source interface converter. The advantage of the voltage source interface converter is observable in the near instant after the disturbance. The voltage source converters provide rapid current injection as compared to the current source interface. However, due to the nature of the energy balance, following the rapid injection of energy at the instant of disturbance, the injection from the voltage source interface converter drops, and the action of the control loops become dominant. The current source interface converter on the other hand, is unable to contribute short circuit at the instant of disturbance, and thus, only the action of the control loops is present. In both schemes, after the first 100ms, the delivery of energy into the network is roughly the same, and thus, from the perspective of arresting the frequency decline, it may be possible to continue to use current source interface converters. But, it must be stated that this conclusion is only from the perspective of arresting the frequency decline, given that the rate of change of frequency is measured as a moving average over 500ms.

In the real Texas power system, to plan for frequency response reserves, a loss of 2750 MW of generation, with a credit of 1209 MW of fast acting load response, is the benchmark event for analysis [27]. These numbers align with the net generation loss event that has been analyzed in this scenario. It is thus worthwhile to check if the same trend of rate of change of frequency observed above, holds if both the generators were tripped at the same time in this scenario. Table IV tabulates the rate of change of frequency at the terminals of the 16 generator machines across all 5 cases with simultaneous trip of two 1.2 GW generators.
for Cases 1, 2 and 3 intersect at around 500ms after the event. For all five cases, the total active power in Area 5 (excluding the two generation sources that tripped) and Area 8 is shown in Fig. 13. In Area 5, immediately upon the occurrence of the disturbance, the large amount of energy supplied by the synchronous machines in Case 1 is clearly observable. However, as time advances, the converters catch up in energy injection. In Area 8, in Cases 2 - 5 with the large presence of converters, the 5 remaining machines (buses 8071, 8088, 8129, 8130 and 8131) constitute approximately 64% (both by capacity and MW) of entire area’s in service generation. Hence, when the converters in Area 5 are slow to begin injection of energy, the machines in Area 8 inject more energy than they did in Case 1.

While optimal tuning of the controllers is not within the scope of this paper, a commentary is required regarding the presence of the integral controller in the angle droop path. Conventional synchronous machine governor controls do not include integral terms within the primary frequency response time frame as the mechanical time constants of the rotor shaft would result in a slow moving speed signal which in an integral controller would result
in a high gain due to the structure of the controller. This high value of gain could then cause undue stress on the rotor shaft. However, in an all inverter system, the input to the integral controller is electrical frequency which is a faster signal as compared to mechanical speed of a turbine. Thus, this faster moving signal would reduce the net gain of the controller while still bringing out the desired effect of driving the steady state error to zero. When the power system moves towards an all inverter system, this aspect could be exploited to bring about constant frequency operation. Even in an all inverter system, a large value of integral gain could potentially lead to deterioration of system stability. To illustrate this, Case 2 was chosen as a test scenario with different values of $K_{ferr}$. For the trip of the two generators, Fig. 14 shows the average system frequency. With a value of 10.0, the stable constant frequency response is observable. With a value of 80.0, the increased integral gain at first seems to show a more stable response. In both these conditions, the delay in communicating measured electrical frequency ($f$ in Fig. 4) was assumed to be 10ms. But, upon increasing the delay to 500ms (as can be the case in many state of the art inverter plants [33]), it can be seen that even the initial value of $K_{ferr} = 10.0$ can result in an unstable trajectory. The trajectory can be stabilized in one manner by reducing the value of $K_{ferr}$ to 2.5.

**D. Energy injection immediately after the disturbance**

But, the question then is, how much additional/reduced energy is injected in each case? In order to approximately compute the energy injected, the total active power curve in Area 5 was integrated over the duration of the simulation using a composite trapezoidal numerical integration rule, and the results are tabulated in Table V. In addition to evaluating the energy injected over the entire duration of the simulation, the energy injected immediately after the disturbance (from 9.99s to 10.50s and from 9.99s to 11.014s) was also approximately calculated. The energy values in the table are in units of MW·seconds approximated to the nearest integer. It can be seen that in Area 5, although the synchronous machines in Case 1 inject a large amount of power immediately upon the occurrence of the disturbance to arrest the frequency decline, the energy injection in comparison to the energy injection of the all converter situations of Cases 2 and 3, is almost similar in the first 500ms after the disturbance. This is also confirmed from Fig. 12 wherein the system frequency in Cases 1, 2 and 3 intersect at around 500ms after the disturbance. The energy evaluation also provides an idea of the additional MW·seconds of energy required from converter resources to be operated in the constant frequency control mode, as opposed to operation in a frequency droop control mode.

### TABLE V: Energy (in MWs) injected from Area 5 for simultaneous trip of two 1.2 GW generators across all cases

<table>
<thead>
<tr>
<th>Time duration</th>
<th>Case 1</th>
<th>Case 2</th>
<th>Case 3</th>
<th>Case 4</th>
<th>Case 5</th>
</tr>
</thead>
<tbody>
<tr>
<td>0s to 30s</td>
<td>316113</td>
<td>322585</td>
<td>322212</td>
<td>317174</td>
<td>317095</td>
</tr>
<tr>
<td>9.99s to 10.50s</td>
<td>5540</td>
<td>5439</td>
<td>5413</td>
<td>5355</td>
<td>5338</td>
</tr>
<tr>
<td>9.99s to 11.014s</td>
<td>10665</td>
<td>10913</td>
<td>10892</td>
<td>10653</td>
<td>10638</td>
</tr>
</tbody>
</table>

As the number of synchronous machines reduce in the system, due to the loss of the mechanical characteristics, the coupling between active power and voltage magnitude becomes more pronounced. This is further enhanced by the use of angle droop control as the changes in absolute magnitude of angle across long transmission lines is influenced by the voltage magnitude at the ends of the lines and the power flowing across the line. To observe the impact of the two generation trip on the voltages in the system, at every time step, the minimum voltage magnitude across the entire system for this event is shown in Fig. 15. It can be seen that for all the converter cases, the voltage control is stricter. This is due to two primary reasons:

1) In the synchronous machines case, although the machines inject energy in the first 500ms after the
although the converters have a slightly slower rate of injection of energy, there is no reduction in energy once the energy injection has begun. This is of course under the assumption that the controllers of the converter plants are well tuned and that the dc bus is stiff. However, in the first 500ms when there is a slower rate of energy injection from the converters, the angles across the systems do spread faster, and this is observable from the greater rate of disturbance, the energy injection reduces in the subsequent couple of seconds as is seen from Fig. 13. This transient reduction in energy is common and is due to the natural motion of the rotors of the machine accelerating/decelerating against each other. This reduction in energy injection few seconds after the disturbance would cause the angles to spread across the system which causes the voltages to reduce. In the cases with the converters, although the converters have a slightly slower rate of injection of energy, there is no reduction in energy once the energy injection has begun. This is of course under the assumption that the controllers of the converter plants are well tuned and that the dc bus is stiff. However, in the first 500ms when there is a slower rate of energy injection from the converters, the angles across the systems do spread faster, and this is observable from the greater rate of disturbance, the energy injection reduces in the subsequent couple of seconds as is seen from Fig. 13. This transient reduction in energy is common and is due to the natural motion of the rotors of the machine accelerating/decelerating against each other. This reduction in energy injection few seconds after the disturbance would cause the angles to spread across the system which causes the voltages to reduce. In the cases with the converters,
of change of voltage in that small time frame.

2) The static excitation system used for the synchronous machines have not been tuned to optimal values which could otherwise possibly allow faster voltage control.

E. Power sharing across converters

With the operation of the constant frequency control established, and the implications on frequency response discussed, henceforth, Cases 4 and 5 are not considered in the discussion. With constant frequency operation, upon the occurrence of a disturbance (generation or load change), a valid concern is whether all areas will share the burden of the disturbance (as it presently occurs nowadays due to frequency droop control). In the constant frequency control scheme, based upon the proportion of the deviation of the terminal voltage bus angle from a set reference, the power command of the converters is changed. With such a control, it is possible to share the burden of a disturbance among the various sources in the system. For the two generation trip event, the total active power in Areas 5 and 2 is shown in Fig. 16. The sharing of power across the areas can be inferred from this figure and as the sharing of power is now linked to the deviation of bus voltage angle, the topology of the electrical network would play a large role in determining the areas which are able to share more proportion of the burden. With a large portion of the fleet being converter interfaced sources, the implications of uncertainty in input energy have to also be analyzed. In [1], a stochastic based framework was explored to look into the various combinations of input energy uncertainty that can occur with a large fleet of converter based generation, but a small system was used in the study with the converters on conventional frequency droop control. Continuing the analysis, the aim is here to study the impact of the uncertainty on the constant frequency control scheme, when spread across the large system. In comparison to a scenario where there is sufficient available headroom, if the available energy headroom on converters is suddenly limited, then angles across the system would change faster and by a larger magnitude, causing converters which have available headroom to pick up more of the burden. This happens even in a conventional frequency droop control scheme. However, due to the fast nature of the controls on the converter, it is possible that this fast change in angle can cause a fast voltage reduction in the system. For the same two generation trip event, a simulation was carried out for Cases 2 and 3, but with the headroom of the converters in Areas 2 and 5 reduced by 20%, one second after the occurrence of the disturbance. Area 2 was chosen in addition to Area 5 as pre-disturbance, Area 5 imports active power from Area 2. While it could be rare that there is a sudden decrease in available energy across a vast geographical area (as is the geographical spread of these two areas), such a scenario serves as a benchmark test case. Fig. 17 shows the minimum voltage magnitude across the system for both cases in comparison to the minimum voltage magnitude when the headroom is sufficient. As the headroom decreases in these areas, the voltage across the system becomes increasingly oscillatory, and as expected, the magnitude of the sag deepens. In these scenarios, the converters were operated in a Q priority mode wherein, during the disturbance, priority is given to the injection of reactive current over the injection of active current.

In the present power system, the deviation in frequency is used as an integral component in the calculation of area control error (ACE) which drives the implementation of secondary frequency control. But in the constant frequency control model implemented here, the frequency deviation is essentially zero within a few seconds after the disturbance. In such a situation, the research question that arises is would the tie line deviation error be a sufficient signal for the implementation of the secondary frequency control?

By enabling the ‘Tie line deviation’ control block, Fig. 18 shows the total active power output in Areas 5 and 2 for the two generation trip event. It can be seen by just using the tie line deviation as a signal, the individual areas are able to respond to the changes in command to either

![Fig. 18: Active power from areas 5 and 2 showing provision of long term power support](image-url)
increase or decrease their power output resulting in sources in Area 5 having to increase their power output by almost the total generation loss, while sources in Area 2, after having initially shouldered part of the burden to bring the frequency back to nominal, go back to their pre-disturbance values. In this paper, response of converter controls along with energy delivery has been examined only for a ‘clean trip’ of generation wherein large generation units trip without an initiating fault. This is in line with conventional frequency response studies that are carried out. Response of the constant frequency control to faults and fault ride through, and is a topic of future research.

4. Conclusion

To conclude this paper, few take away points are:

1) The constant frequency control mode is able to bring the entire system electrical frequency back to the nominal value within a few seconds after the disturbance, even with the presence of synchronous machines.

2) With constant frequency control mode, apart from the first 200-300ms after a disturbance, there is little difference between the workings of a current source interface converter and a voltage source interface converter.

3) With rate of change of frequency evaluated 500ms after the disturbance, operation of a majority converter dominant system, results in no significant change in the rate of change of frequency at the synchronous machine terminals that are located electrically close to the point of disturbance. However, for machines that are located electrically farther away, an increase in the rate of change is observed.

4) Evaluation of the energy injected by the converters in the few milli-seconds after the disturbance provides an insight into the capacity planning requirements for the satisfactory operation of a converter dominated power system.

5) The angle droop control mode allows for converters in all areas to share the burden of generation – load imbalance. However tuning of the gain of this controller has to be with consideration of the delay is communication of electrical frequency measurement.

6) And, only tie – line active power deviation could be used successfully as a control signal for secondary frequency control.

The results shown in this paper validate the concept of constant frequency operation, and the possible ability to operate an inverter dominated bulk power system with inverters controlled as current sources, while making use of their inherent voltage source property. Further, with constant frequency operation, it has been shown that sharing of power across inverters both in the short term, and across areas in the long term is feasible. This validation is important in the context of constant frequency operation because in today’s state of the art operation of the bulk power system, deviation in frequency plays a very important role in defining the sharing of power across energy sources both in the short term (primary frequency response) and in the long term (secondary frequency response). But by bringing about an operation at constant frequency, the deviation in frequency is made zero within 5s of the disturbance. In such a scenario, whether inverter resources would share power across multiple areas is a valid concern and the results provide a possible viable path through the concept behind the use of the active power controllers as carried out in this paper. Additionally, due to the fast nature of constant frequency controls, wherein the electrical quantities of the network are directly controlled, it can potentially help improve the transient stability of the network in a manner similar to the operation of FACTs devices. This is however a topic of future research.

5. Appendix

The invocation of the modular dynamic models in GE-PSLF, and the values of the parameters for the models is provided here:

A. Current source interface model

reg a BUS NUM "BUS NAME" BUS KV "ID" : #9 mva=RATING "lvplsw" 0.0 "rrpwr" 10.0 "brkpt" 0.9 "zerox" 0.4 "lvpl1" 1.22 "vtmax" 1.2 "lvplnt1" 0.8 "lvplnt0" 0.4 "qmin" -1.3 "accel" 0.70 "tg" 0.02 "tftr" 0.02 "iqrmax" 99.0 "iqrmin" -99.0 "xe" 0

B. Voltage source interface model

modelname BUS NUM "BUS NAME" BUS KV "ID" : #9 mva=RATING "rsrc" 0.004 "xsrc" 0.15 "Imax" 1.1 "Tr" 0.02 "Kppll" 60.0 "Kipll" 1400.0 "PLLmax" 72.0 "PLLmin" 48.0 "Kip" 5.0 "Kii" 30.0 "Te" 0.01 "rrpwr" 10.0
C. Electrical control model

D. Active power controller

6. References


Abstract
Enhanced standards have recently been implemented in Australia’s National Electricity Market (NEM) requiring utility-scale generation to remain connected to the grid during and after a number of voltage disturbances occurring in quick succession. These new standards currently apply prospectively to all generation technologies and aim to strike a balance between power system security requirements and maintenance of plant integrity.

The criteria forming the basis of an assessment against the proposed requirements were:
• The total number of disturbances within predefined sliding time windows (NF);
• The accumulated disturbance duration (Δt); and
• The sum of changes in voltage by the duration of the disturbance (ΔV x Δt).

Power system modelling and analysis demonstrates that these standards can be met by a range of new and existing synchronous and inverter-connected generation technologies accounting for their actual connection points to the wider network. Specific advice on the types of disturbances that should be investigated is also provided, accounting for actual fault patterns observed in transmission and distribution networks. These results indicate that the standards are practical and achievable with full consideration of limitations of the power system and different generation technologies.

1. Introduction
Historically, there were very few explicit requirements internationally for generators to ride through multiple successive power system disturbances. One of the few examples of known requirements in this regard is the Danish Technical Regulation [1]. Lessons learned from the South Australian black system event on 28 September 2016 [2] and other observed disturbances in the Australian National Electricity Market (NEM) demonstrate that the Danish requirement would not be adequate to ensure NEM power system security under extreme operating conditions. For example, the number of disturbances occurring in practice in the NEM could well exceed the pre-determined number of disturbances required in the Danish regulation.

Technical requirements for multiple disturbance ride-through capabilities were included in German standards in October 2018 [3-5]. These requirements are a step forward in maximizing the utilization of the capability that a generator can provide. However, they were primarily developed for wind generation technology, which will have different capabilities and limitations to other generation technologies. Furthermore, these standards do not provide the level of detail and comprehensive boundary conditions for plant manufacturers and project developers to clearly determine power system operating conditions for which compliance is, or is not, required.

The capability of generating plant to withstand multiple successive voltage disturbances is becoming a more important consideration as the generation mix in the NEM shifts from predominantly synchronous generation to an increasing proportion of inverter-connected generation, including all types of wind turbines, solar inverters and battery energy storage systems.

Until October 2018, the NEM rules prescribed the types of voltage disturbance that a generating system must be capable of riding through in terms of severity and duration, but did not specifically contemplate multiple...

KEYWORDS
Fault ride-through capability, multiple voltage disturbances, transient stability, power system modelling
successive faults. Many inverter-connected generators are connected to distribution networks, or remote parts of the transmission networks, due to the abundant wind or solar resources at these locations. These parts of the power system are often more prone to multiple power system faults, as geographically they tend to be more exposed to natural disasters or adverse weather events, such as bushfires.

In these conditions, inability to ride through several successive power system faults could result in a significant disconnection of generation, with the potential to cause cascading tripping events and eventual blackouts.

Power system faults are inherently unpredictable. As observed historically, not only one but a series of successive faults could occur in the power system. Generators’ capability to ride through such successive faults must be examined, to manage the risk of generator energy output suddenly ceasing due to these successive faults. Catastrophic power system failure could happen if these risks are not understood and managed properly.

The networks in the NEM do experience successive faults caused by extreme weather conditions such as thunderstorm and cyclones, as well as natural disasters such as bushfires. The historical events and records outlined in Section 2 below describe how the occurrence of multiple faults is a real and ongoing issue in the contemporary NEM, not simply a theoretical exercise.

Reference [6] noted potential concerns due to electrical, mechanical, thermal, and torsional impacts of riding through multiple voltage disturbances on synchronous machines. These limitations were well understood at the time of developing the Australian requirements. A generating plant is indeed permitted to be disconnected by its protection functions under extreme operating conditions, where riding through additional or more severe multiple voltage disturbances could otherwise result in severe adverse impacts on the physical integrity of the plant. This assumes that any inherent plant limitations can be predicted beforehand with the use of appropriate simulation models that correctly account for any such susceptibility mechanisms.

Section 2 of this paper reviews the historical occurrence of sequential multiple disturbances in NEM power system. Section 3 presents the multiple fault ride-through requirement for new NEM generating systems introduced in 2018, and Section 4 explains the assessment criteria for these new requirements, applied to new generating systems during the grid connection process. Sections 5 and 6 provide evidence of the validity and practicality of the multiple fault-ride through requirements, using survey feedback and software simulation.

2. Historical Experience

2.1. South Australia black system, 28 September 2016

In the lead-up to the collapse of the South Australian power system on 28 September 2016, a series of faults were experienced by the region’s power system as transmission infrastructure was damaged by extreme weather. In the final 30 minutes preceding system collapse, seven faults occurred, with five faults occurring within the last two minutes [2]. This resulted in six voltage disturbances as the fifth fault caused an unsuccessful auto-reclosure.

This number of faults within two minutes activated hitherto unknown protection mechanisms in a large number of wind power plants in the region, which disconnected the wind turbines after detecting three to six successive voltage disturbances [2]. This resulted in six voltage disturbances as the fifth fault caused an unsuccessful auto-reclosure.

This number of faults within two minutes activated hitherto unknown protection mechanisms in a large number of wind power plants in the region, which disconnected the wind turbines after detecting three to six successive voltage disturbances [2]. This active power imbalance precipitated the collapse of the region’s power system. This practical example highlights the need to have clearly defined performance standards on plant response to multiple fault ride-through.

The pre-set protection settings of all impacted wind farms were increased following the South Australian black system event. The positive impact of this increase was demonstrated within six months when, on 3 March 2017, the South Australian power system was subject to three severe faults within two seconds. Increased pre-set protection settings of wind farms allowed them to successfully ride through these three severe faults.

2.2. General Experience

Fault records from the NEM regional power systems in New South Wales, Queensland, and South Australia were analyzed as representative examples to determine the maximum historical number of faults which occurred within 2-, 30-, and 120-minute periods.
As specified in Table 1, the new performance standards include two bands of requirements – the automatic access standards and the minimum access standards. As required in the NER, the automatic standards define the highest technical performance standards which can be required for generator connection, while the minimum standards are the lowest performance requirements that can be accepted.

The connecting generator can negotiate the actual technical requirement (defined as a negotiated access standard) which it must comply with, between the minimum and automatic standards. The level at which a negotiated access standard is set often depends on several factors, such as generators’ size, location of connection (including network topology), and generation technology. However, the NER now require that technical standards be set as close as possible to the automatic standard.

In the context of the multiple fault ride-through requirements, all new generation must at least be able to ride through the fault sequence described in the minimum standards.

The following sections provide a detailed description of the key differentiators between the automatic and the minimum access standards for these ride-through requirements.

### 3.1 Time between disturbances

The automatic access standard does not specify any value or range of values for the minimum time difference between successive disturbances, because it is not possible to control or anticipate the next disturbance due to its inherent randomness. Any two successive disturbances could be zero seconds apart. The minimum access standard allows for a 200 ms time delay between the clearance of a preceding disturbance and the occurrence of the succeeding disturbance.

It should be noted that the historical fault data in New South Wales and Queensland transmission networks do not consider a failed autoreclosing event as a second disturbance, whereas South Australia’s historical fault data does count this as a second disturbance.

Figure 1 shows the maximum number of historical faults within various time frames during a 10-year period for the South Australian and New South Wales transmission and distribution (66 kV only) networks, and Queensland transmission networks. Data was gathered by individual transmission network asset owners for their networks, looking at the highest number of successive voltage disturbances as recorded historically, in the respective time window, i.e. 2 minutes, 30 minutes and 120 minutes.

The data shows that a large number of voltage disturbances in quick succession have occurred in the past in various regions of the NEM.

### 3. New Requirements

To support ongoing power system security and stability as the NEM transitions to a low emission future power system with a high penetration of inverter-connected generation, in 2017 AEMO proposed a new requirement for generators to ride through multiple successive power system disturbances, based on direct experience and learnings from the 2016 South Australia black system event.

This requirement was developed after extensive analysis and simulation. The Australian Energy Market Commission (AEMC) then assessed the proposed requirement in consultation with energy industry stakeholders, before including it in the National Electricity Rules (NER) for the NEM. The multiple disturbance ride-through requirement adopted in the NEM from October 2018 is summarized in Table 1, with specific terminology definitions in Table 2.

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Figure 1 - Historical faults per period for the South Australian, New South Wales and Queensland regions of the NEM

![Figure 1](image-url)
### Table 1 - Requirements for Multiple Disturbance Ride-through

<table>
<thead>
<tr>
<th>Elements</th>
<th>Automatic acceptance standard</th>
<th>Minimum standards</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total number of disturbances for 5-minute period</td>
<td>15</td>
<td>6</td>
</tr>
<tr>
<td>Sliding window reset time</td>
<td>5 minutes</td>
<td>30 minutes$^3$</td>
</tr>
<tr>
<td>Accumulated disturbance duration (milliseconds)</td>
<td>1800</td>
<td>1000</td>
</tr>
<tr>
<td>Sum of $\Delta V \times \Delta t$ (pu.second)</td>
<td>1.0</td>
<td>0.5$^3$</td>
</tr>
<tr>
<td>Number of deep disturbances</td>
<td>6</td>
<td>3</td>
</tr>
<tr>
<td>Minimum time difference between successive disturbances</td>
<td>No minimum$^4$</td>
<td>200 ms</td>
</tr>
</tbody>
</table>

Type of disturbances to be considered$^5$

- One disturbance cleared by breaker-fail protection system
- One long-duration shallow disturbance, e.g. 80% residual voltage for 2 s
- One deep three-phase disturbance (or two deep three-phase disturbances in parts of network where a three-phase auto-reclosing is permitted)
- Remaining disturbances are unbalanced
- An unsuccessful auto-reclosure is counted as two disturbances

<table>
<thead>
<tr>
<th>Terms</th>
<th>Definition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Accumulated disturbance duration ($\Delta t$)</td>
<td>The total time for which the connection point voltage is below the lower nominal operating band of 0.9 per unit.</td>
</tr>
<tr>
<td>Deep disturbance</td>
<td>When the connection point voltage is below 50%. This is generally the lowest of the three-phase voltages. When a fault ride-through strategy uses the positive-sequence voltage for initiating the ride-through sequence, the positive-sequence voltage will be used for assessing the number of deep voltage disturbances in Table I.</td>
</tr>
<tr>
<td>Sliding window reset time</td>
<td>The total time from the first disturbance in a sequence of disturbances (as per Table I) that must expire before a generating system is required to withstand further faults.</td>
</tr>
<tr>
<td>Sum of $\Delta V \times \Delta t$ ($\Delta V \times \Delta t$)</td>
<td>The time integral of the connection point voltage and 0.9 per unit, when the voltage is below 0.9 per unit</td>
</tr>
</tbody>
</table>

1 This means the generating system must withstand the same number of voltage disturbances within a five-minute interval. However, no further ride-through capability is required until 30-minute interval expires.

2 These requirements apply in addition to standing NER requirements.

3 Any non-credible contingency, or any individual contingency causing a synchronous generating system to exceed its critical fault clearance time, is excluded from assessment of the access standards.

4 Meaning that two successive disturbances can occur one after another with practically zero time difference. However, in reality not all 15 faults will occur with 0 ms separation. Randomly distributed time differences between successive disturbances, ranging from 0 to 200 ms, may be applied. The sequence studied should include at least two pairs of successive disturbances with 0 ms in between.

5 Disturbances should not result in the generating system under consideration being islanded, or cause large sections of the transmission or distribution network to be lost.
3.2 Generation technologies

Synchronous machines and type 1-2 wind turbines are directly coupled to the power system and their primary components are, therefore, exposed to various impacts of disturbances, including thermal, mechanical, and electrical adverse impacts. Furthermore, type 3 wind turbines are loosely coupled to the network and could have some susceptibility to the impact of disturbances mentioned above.

Inverter-connected generating systems are generally less susceptible to disturbances due to full or partial decoupling from the power system disturbance, with their fast control systems further minimizing the impact of disturbances.

Given these inherent technology differentiators, an acceptable performance standard for inverter-connected generating systems should be at, or as close as possible to, the automatic access standard, whereas a wider range of negotiated outcomes may be acceptable for synchronous machines considering the key technological differentiators discussed.

3.3 Diversity in physical locations and severity of disturbances

The access standards acknowledge that the occurrence of a large number of deep voltage disturbances in close proximity to a generating system could result in the generating system being islanded and inoperable, or large sections of adjacent transmission or distribution network being out of service. The access standards specify the maximum number of deep disturbances (with a connection point voltage of less than 50%) to be considered, with the remaining shallower disturbances resulting in a residual voltage of greater than 50%. For each connection, the selection of the number of deep and shallow disturbances must consider the characteristics of the surrounding power system, thereby applying the disturbances at a wide variety of physical locations so as not to cause the generating system to be islanded.

3.4 Fault type and duration

Consideration must be given to the disturbances listed in “Type of disturbances to be considered” in Table 1 to assess whether the plant in question can meet the requirements for multiple voltage disturbances.

The fault clearance time for each fault in isolation must be within the relevant primary protection or circuit breaker failure clearance time for the specific faults appropriate to the generating system under consideration, and as specified in the generator performance standards for that facility.

The fault clearance times applied to synchronous machines for this assessment must be below the respective critical clearing time. Longer duration faults must not be applied.

Some generating systems connected to remote distribution systems can be subject to deep faults with fault clearance times in the order of several seconds with possible autoreclosure. These types of disturbance affect a very limited part of the network. An inability to ride through a number of such disturbances will have limited impact on power system security, and such disturbances with prolonged clearance time must be assessed individually as a part of the generator connection process. This is not in the scope of the multiple disturbance ride-through requirements.

In recognition of this limitation, and that a one-second clearance time for a deep fault would exceed the minimum access standard sum of ΔV x Δt criterion, the maximum fault duration to be applied in multiple fault ride-through assessments should not exceed one second.

An example of such a disturbance sequence is illustrated in Figure 2.

In the above example, the generating system successfully rode through the first four disturbances. The fifth
disturbance caused the connection point voltage to drop below 50% for five seconds. The generating system is not, therefore, required to ride through the fifth long duration disturbance.

4. Assessment Criteria

The inability of generation to withstand multiple faults in quick succession could result from electrical, mechanical, or thermal limitations (or failures) of primary plant components, or settings of control and protection systems. This can, in turn, trigger a rapid cessation of energy generation.

The limitations are generally an accumulation of the effect of each individual disturbance on the generating systems. The sudden loss of numerous generating facilities across the network leads to potential risk of cascading failure across parts of the power system.

Recognizing this, and the need to strike a balance between power system security and maintaining plant integrity due to multiple voltage disturbances in quick succession, the following assessment criteria are applied to determine whether a proposed generating system can meet the multiple fault ride-through access standards:

- An accumulated disturbance duration (Δt).
- A total number of disturbances within pre-defined sliding time windows (NF).
- Sum of changes in voltage by the duration of the disturbance (ΔV x Δt).

AEMO will be satisfied that a generating system can meet the access standards when at least one of these criteria is met.

In developing these criteria, AEMO considered the physical and design limits of various generation technologies, and the types of disturbances (by reference to severity and accumulated duration) a generating system must ride through to maintain power system security in a practical Australian environment.

More information about how each of the criteria is to be assessed is in the following sections.

4.1 Accumulated disturbance duration (Δt)

This is the cumulative amount of time where the connection point voltage is below 90% of the normal voltage (Δ|VN| > 0.1 per unit [pu]), where Δ|VN| is defined as the voltage drop at the connection point from 90% of the normal voltage.

4.2 Number of disturbance (NF)

This is the total number of power system disturbances calculated in a sliding time window of 5 minutes or 30 minutes, for the automatic and minimum access standards respectively. These disturbances would result in a voltage drop at the generating system’s connection point. The only disturbances to be considered are voltage disturbances resulting from natural power system disturbances, excluding any recurring voltage disturbances due to the incorrect design of a control system.

Sum of changes in voltage by the duration of the disturbance (ΔV x Δt).

This is the time integral of voltage difference between 90% of the normal connection point voltage and the connection point voltage during disturbances when the connection point voltage is lower than 90%. The (ΔV x Δt) is measured in perunit seconds (pu.s) where 90% normal voltage represents 0.9 per unit.

This is shown in Figure 3. The blue curve is the connection point voltage profile, while the red dashed horizontal line indicates 90% normal voltage. The shaded area is defined as sum of ΔV x Δt, for this particular example, in pu.s. For long, shallow faults, this criterion could be the first met.

5. Practical Application of Requirements

The AEMC conducted a survey [7] of various equipment manufacturers in 2018, regarding the capability of their existing equipment to meet the proposed multiple fault ride-through requirement.

The survey results indicated 80% of the equipment
manufacturers (including manufacturers of synchronous generators and inverter-connected generating systems) could readily meet the proposed minimum standards using their existing products, with little or no additional cost, for all types of equipment they make. The survey results also indicated over 80% of the equipment manufacturers could either readily meet the proposed automatic standards, or meet them with modification to their existing products, with likely material but manageable additional cost. No respondents raised concerns that their equipment could not meet the minimum access standards at all.

6. Simulation Results Supporting the Requirements

AEMO undertook simulation case studies to confirm that the proposed access standards could be met by new and existing generating systems. The simulations were conducted using actual data and simulation models sourced from proposed and existing generation.

The focus of simulation studies presented in this section is to demonstrate that the power system to which these generating systems are connected will remain stable and operable in response to a number of voltage disturbances in quick succession, and to confirm the suitability and practicality of the levels of the three assessment criteria set out in Section 4. Revised Power System Model Guidelines were published on 1 July 2018 [8] to ensure that models provided are an accurate representation of plant and plant responses for multiple successive disturbances. The model must include the most restrictive electrical, mechanical, or thermal protection of the plant with respect to multiple voltage disturbances in quick succession, and calculate dynamically and accumulatively the impact of multiple voltage disturbances.

Each assessment used a simulation script which automatically determined the next fault to apply in the simulation. The script determined the sequence of faults which could achieve the worst possible voltage profile at the location of interest (usually the connection point of a generating system), as described by the corresponding access standards applied in the assessment. The script did not apply any fault which could island any section of the power system, and only applied disturbances according to the “Type of disturbance to be considered” in Table 1.

For wind and solar power plant assessments, the postcontingency aggregate short circuit ratio (SCR) at the connection point was calculated to ensure the SCR, accounting for the impact of nearby generating systems, was above the minimum SCR withstand capability of the generating units assessed.

The process stopped applying further disturbances once the resultant voltage profile reached the threshold of any of the three assessment criteria in Section 4, as specified by the access standards applied. The response of the generating system was then examined to identify whether it remained connected or tripped during the fault sequence. The process also recorded which assessment criteria were achieved before the simulation was stopped.

6.1 Simulation Result Summary

Table 3 presents the generating systems reported on, and which criteria were met following assessment of each generating system. Table 4 presents the assessment outcome of each case.
### Table 3 - Generating System Investigated in the Assessment

<table>
<thead>
<tr>
<th>Technology</th>
<th>System Strength(^7)</th>
<th>Levels of Interconnection(^8)</th>
<th>Limiting Factor(^9)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Synchronous generating system in highly interconnected transmission network</td>
<td>N/A(^{10})</td>
<td>6</td>
<td>NF, (\Delta t) of minimum access standard</td>
</tr>
<tr>
<td>Synchronous generating system in transmission network with little interconnection</td>
<td>N/A</td>
<td>1</td>
<td>NF of minimum access standard</td>
</tr>
<tr>
<td>Solar farm in highly interconnected transmission network</td>
<td>High</td>
<td>6</td>
<td>NF of automatic access standard</td>
</tr>
<tr>
<td>Wind farm in transmission network with little interconnection</td>
<td>Medium</td>
<td>2</td>
<td>NF, (\Delta t) of automatic access standard</td>
</tr>
<tr>
<td>Solar farm in distribution network (with highly interconnected transmission network upstream)</td>
<td>Low</td>
<td>4</td>
<td>(\Delta V \times \Delta t) of automatic access standard</td>
</tr>
</tbody>
</table>

7 A SCR > 5 is considered as high, 3<SCR<5 as medium, and SCR < 3 as low system strength conditions.
8 The level of interconnection is defined as the number of circuits connecting a transmission busbar (110 kV and above) into which the generating system connects, to the rest of the power system. Double circuits mounted on the same tower are considered as two circuits.
9 These are the assessment criteria met by the generating system under consideration.
10 This is because the instability mechanism associated with synchronous machines is generally manifested through rotor angle instability and loss of synchronism, as opposed to low SCR conditions. For this reason, the use of SCR is not the most appropriate metric for assessing instability of synchronous machines under varying levels of system strength conditions.
11 This is because the instability mechanism associated with synchronous machines is generally manifested through rotor angle instability and loss of synchronism, as opposed to low SCR conditions. For this reason, the use of SCR is not the most appropriate metric for assessing instability of synchronous machines under varying levels of system strength conditions.
12 Although the upstream transmission network is highly interconnected, the solar farm is radially fed from the distribution network to which the solar farm is connected, thus making the SCR very low.

### Table 4 - Simulation Results for Generation Successfully Riding Through Multiple Disturbances

<table>
<thead>
<tr>
<th>Technology</th>
<th>Case ID</th>
<th>Sum of (\Delta V \times \Delta t)</th>
<th>Total disturbance duration</th>
<th>Total no. of disturbances</th>
<th>No. of deep disturbances</th>
<th>Pre-contingency aggregate SCR</th>
<th>Post-contingency aggregate SCR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Synchronous generator in highly interconnected transmission network</td>
<td>1a-1</td>
<td>0.306</td>
<td>0.971</td>
<td>6</td>
<td>3</td>
<td>N/A(^{11})</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>1a-2</td>
<td>0.321</td>
<td>0.987</td>
<td>6</td>
<td>3</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>1a-3</td>
<td>0.371</td>
<td>1.162</td>
<td>6</td>
<td>3</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Synchronous generator in transmission network with little interconnection</td>
<td>2-1</td>
<td>0.377</td>
<td>0.912</td>
<td>6</td>
<td>3</td>
<td>N/A(^{11})</td>
<td>N/A</td>
</tr>
<tr>
<td></td>
<td>2-2</td>
<td>0.430</td>
<td>0.987</td>
<td>6</td>
<td>3</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>2-3</td>
<td>0.366</td>
<td>0.891</td>
<td>6</td>
<td>3</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Solar farm in highly interconnected transmission network</td>
<td>3-1</td>
<td>0.492</td>
<td>1.578</td>
<td>15</td>
<td>5</td>
<td>7.77</td>
<td>4.41</td>
</tr>
<tr>
<td></td>
<td>3-2</td>
<td>0.533</td>
<td>1.749</td>
<td>15</td>
<td>5</td>
<td></td>
<td>5.72</td>
</tr>
<tr>
<td></td>
<td>3-3</td>
<td>0.552</td>
<td>1.767</td>
<td>15</td>
<td>5</td>
<td></td>
<td>5.43</td>
</tr>
<tr>
<td>Wind farm in transmission network with little interconnection</td>
<td>4-1</td>
<td>0.573</td>
<td>1.764</td>
<td>15</td>
<td>6</td>
<td>3.73</td>
<td>1.45</td>
</tr>
<tr>
<td></td>
<td>4-2</td>
<td>0.572</td>
<td>1.815</td>
<td>15</td>
<td>6</td>
<td></td>
<td>1.73</td>
</tr>
<tr>
<td></td>
<td>4-3</td>
<td>0.573</td>
<td>2.309</td>
<td>15</td>
<td>6</td>
<td></td>
<td>1.76</td>
</tr>
<tr>
<td>Solar farm in distribution network connecting into highly interconnected transmission network</td>
<td>5-1</td>
<td>1.013</td>
<td>1.705</td>
<td>5</td>
<td>5</td>
<td>1.99(^{12})</td>
<td>1.80</td>
</tr>
</tbody>
</table>

11 This is because the instability mechanism associated with synchronous machines is generally manifested through rotor angle instability and loss of synchronism, as opposed to low SCR conditions. For this reason, the use of SCR is not the most appropriate metric for assessing instability of synchronous machines under varying levels of system strength conditions.
12 Although the upstream transmission network is highly interconnected, the solar farm is radially fed from the distribution network to which the solar farm is connected, thus making the SCR very low.
The total number of disturbances (NF), the accumulated disturbance duration (Δt), and the sum of ΔV x Δt (ΔV x Δt) were calculated for each simulation case and are presented in Table 4.

6.2 Synchronous generator in highly interconnected transmission network

Cases 1a-1, 1a-2, and 1a-3 investigated the multiple fault ride-through performance of a synchronous generating system connected to a highly interconnected transmission network. Figure 4 showed the single line diagram of the part of power system where this synchronous generator is connected.

This generating system was assessed against the minimum access standard, where it was required to ride through six disturbances, three of which would be deep disturbances. The generating system rode through six disturbances in all three cases. Since it met the proposed total number of disturbances criterion, it could meet the minimum access standard.

No case exceeded the proposed sum of ΔV x Δt criterion, therefore, the capability to meet this criterion was not
tested. Assessment against this criterion was unnecessary as the other criteria were satisfied.

The synchronous generator multiple fault ride-through responses in Case 1a-2 are presented in the following figures, including active power and reactive power response, as well as the generator rotor angle.

6.3 Synchronous generator in transmission network with little interconnection

Cases 2-1, 2-2, and 2-3 investigated the multiple fault ride-through performance of a synchronous generating system connecting to a part of the transmission network with little interconnection to the rest of the power system. Figure 8 shows the single line diagram of the network area where this synchronous generator is connected.

As with Case 1a, this generating system could meet the minimum access standard, with the proposed total number of disturbances criterion met in all three cases.

6.4 Solar farm in highly interconnected transmission network

Cases 3-1, 3-2, and 3-3 investigated the multiple fault ride-through performance of a solar farm connecting to a highly interconnected part of the transmission network.
6.5 Wind farm in transmission network with little interconnection

Cases 4-1, 4-2, and 4-3 investigated the multiple fault ride-through performance of a wind farm connecting to a part of the transmission network with little interconnection to the rest of the power system. Figure 10 shows the single line diagram of the network area where this wind farm is connected.

This wind farm was assessed against the automatic access standard, where it was required to ride through 15 disturbances, six of which would be deep disturbances. The wind farm rode through 15 disturbances in all three cases, and could meet the automatic access standard.

Figure 9 shows the single line diagram of the network area where this solar farm is connected.

In all cases, the solar farm rode through 15 disturbances, however only five deep disturbances could be applied without islanding the solar farm or a large section of the transmission network. For each case, the SCR was calculated after all disturbances, and was confirmed to be well above the solar farm’s minimum SCR withstand capability.

No case exceeded the sum of $\Delta V \times \Delta t$, or the accumulated disturbance duration criteria. Nevertheless, the solar farm could meet the automatic access standard, as it met the total number of disturbances criterion.

Figure 10 - Single line diagram for case 4
all disturbances, and was confirmed to be above the generating system’s minimum SCR withstand capability.

6.6 Solar farm in distribution network with highly interconnected transmission network upstream (meeting $\Delta V \times \Delta t$ criteria)

Case 5-1 is presented to demonstrate that the sum of $\Delta V \times \Delta t$ criterion could be met by this type of generating system. The solar farm studied in this demonstration is connected in a distribution network, which is shown in Figure 11.

The results showed only five disturbances could be applied, all of which were deep disturbances. The resulting sum of $\Delta V \times \Delta t$ was 1.013 pu.s (meeting the proposed 1.0 pu.s threshold), while the accumulated disturbance duration was 1.705 s (not meeting the 1.8 s threshold). Since this solar farm met the sum of $\Delta V \times \Delta t$ criterion, it could meet the automatic access standard.

6.7 Failure to ride through multiple disturbances

The suite of simulations also showed that, in some cases, the generating system failed to ride through multiple disturbances. These results were examined to check whether any of the criteria were violated. Table 5 summarizes the results.

Where the generating system failed to ride through multiple disturbances, both the sum of $\Delta V \times \Delta t$ (0.5 pu.s) and accumulated disturbance duration (1 s) were violated, in which case the generating system is not required to ride through such a disturbance sequence.

Under such a scenario, the synchronous generating system is permitted to disconnect via its protection system. If a synchronous generator was exposed to such a fault sequence during real operation, it is likely that the synchronous generator would lose synchronism with the power system due to excessive rotor acceleration during the fault. In this case, the generator would be tripped by its pole slip protection to prevent damage to the generator. The generator’s response to such extreme fault conditions in Case 1b-2 are presented in the following figures.

<table>
<thead>
<tr>
<th>Generator</th>
<th>Case ID</th>
<th>Sum of $\Delta V \times \Delta t$</th>
<th>Total Disturbance duration</th>
<th>Total number of Disturbances</th>
<th>Number of deep Disturbances</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solar farm studied</td>
<td>1b-1</td>
<td>0.513</td>
<td>1.301</td>
<td>6</td>
<td>3</td>
<td>Criteria violated: - Sum of $\Delta V \times \Delta t$ - Total disturbance duration</td>
</tr>
<tr>
<td>Solar farm studied</td>
<td>1b-2</td>
<td>0.588</td>
<td>1.405</td>
<td>6</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Solar farm studied</td>
<td>1b-3</td>
<td>0.505</td>
<td>1.224</td>
<td>6</td>
<td>3</td>
<td></td>
</tr>
</tbody>
</table>
6.8 Impact on synchronous generating systems’ auxiliary supplies

The impact of riding through multiple disturbances on synchronous generating systems’ auxiliary supplies was investigated, to assess whether their withstand capability could be a limiting factor in the generating units’ multiple disturbance ride-through capability.

Induction motors associated with auxiliary equipment such as fans and pumps and their protection were modelled in an electromagnetic transient simulation tool. The results indicated that no auxiliary supplies under investigation tripped or stalled while the generating unit rode through multiple disturbances. This is an expected result, because the motors’ under-voltage protection is typically in the order of 2-3 s, while the total disturbance duration in the multiple disturbance ride-through requirement was less than that. Thus, the limitations of auxiliary supplies for existing synchronous generating
units would likely not be a key determining factor for their capability to ride through multiple disturbances.

7. Conclusion

The simulation results described in this paper show that the new NEM access standards for multiple fault ride-through could be met by different generation technologies and connection points considered in the assessment, using the assessment methodology and criteria described in Section 4.

Where a generating system failed to ride through multiple disturbances, simulation results showed that the disturbance sequence would have resulted in violation of both the sum of $\Delta V \times \Delta t$ and the accumulated disturbance duration criteria. Generating systems are not required to ride through multiple disturbance sequences in this case.

In all simulation cases, the total number of disturbances required by the new access standards was met, which evidentially is the most common restrictive criterion. The accumulated disturbance duration and sum of $\Delta V \times \Delta t$ criteria could be the most restrictive criterion where long and shallow disturbances would have a material impact on the connection point voltage.

Based on these findings, it is concluded the new NEM access standards are practical, and can be met by various generation technologies. These requirements assist in maintaining power system security, maximize the utilization of capabilities which different generation technologies can provide, and recognize the need to maintain the physical integrity of generating plants when subjected to multiple voltage disturbances in quick succession.

8. References

[1] Technical Regulation 3.2.5 for Wind Power Plants above 11 kV, Energinet DK, TR 3.2.5 Revision 4, July 2016


Power System Operation with Reduced System Strength for Inverter-connected Generation during Prior Outage Conditions

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Australian Energy Market Operator (AEMO)

Abstract

Large numbers of inverter-based generators in remote parts of the network present unique challenges to system operators in keeping sufficient system strength to maintain system security. In the National Energy Market (NEM) of Australia, there is an exponential growth in the uptake of inverter-based generators (IBG), particularly solar and wind generation. These generators are often electrically close to each other and can adversely interact under certain system conditions. The system strength available in remote parts of the network is often low and a planned outage of a network element can further reduce the system strength available to these IBGs. This could lead to unexpected and undesirable system responses.

This paper presents the impact of prior network outages on the response of multiple electrically close IBGs in a remote part of the network, and discusses operational measures taken to manage system security during these prior outages while permitting maximum stable output of these generators. Each IBG has been examined individually and collectively to identify its contribution to the undesired system behaviour. A number of system conditions have been simulated based on a detailed and validated electromagnetic transient (EMT) model of the entire region under consideration, to identify the impact of prior outage of a network element on the overall dynamic behaviour of the system and the impact on system security.

Results discussed in this paper apply for prior outage conditions only. While undesired voltage oscillations have been observed more recently in a limited number of cases under system normal conditions, these are not discussed in this paper.

Simulation studies presented in the paper demonstrate that a combination of a prior outage and a forced outage would reduce the system strength available for IBGs below what their control systems have been tuned for. When an element of the network is taken out of service, the system strength declines and can affect plant in the close vicinity of the out of service element. This reduction in the system strength manifested itself in sustained post-fault oscillations which are in breach of system standards for the network and performance standards for the individual generators.

Each IBG in the network under consideration, including inverter connected generation, dynamic reactive support plant and HVDC link, has been investigated for its contribution to voltage oscillations. It is demonstrated that a reduction in the generation of IBGs alone does not have a significant impact on post-fault voltage oscillations. The number of inverters online is a key factor contributing to instability.

Lastly, the paper discusses a remedial measure developed and implemented in practice to eliminate or substantially reduce post-fault voltage oscillations in prior outage conditions.

1. Introduction

The Australian Energy Market Operator (AEMO) operates one of the longest power systems in the world, the National Electricity Market (NEM). It comprises five interconnected regions in the Southern and Eastern side of Australia, all of which have seen exponential recent growth in inverter-based generators (IBG), particularly inverter-connected wind and solar generation. The
with duration ranging from a few days to several weeks. In 2018, AEMO developed and published a new System Strength Requirements Methodology document under the National Electricity Rules. The methodology is applied to determine minimum system strength at transmission network nodes, sufficient to maintain overall power system security [2]. An indirect effect of this requirement is to ensure that the performance of the majority of IBG committed or installed by 1 July 2018 will not be deteriorated significantly below the level accepted under their connection arrangements.

Currently these requirements do not specifically account for the impact of prior network outage conditions, where a planned outage of a transmission line would further reduce the system strength available to IBG [3].

Transmission network asset owners can disconnect a transmission line for reasons including routine or emergency maintenance of the line, or upgrade of insulators or communication infrastructure. The timing and duration of an outage would vary depending on the work carried out.

During a network outage, the system strength support available for IBG further declines. This could result in undesired behaviour of IBG, as often their control system tuning does not account for transmission line outages. Lack of system strength also implies that a given system disturbance could have a larger impact, affecting wider parts of the network compared to higher system strength conditions.

The section of the network with a high concentration of IBG, as studied in this paper, is shown in Figure 1. It includes approximately 950 MW of installed IBG and a further 600 MW currently going through the connection process. The nearest synchronous generators are approximately 600 km away from the concentrated IBG. Although this sub-network is interconnected to other regions of the NEM, their system strength contribution is negligible. A number of long duration outages are planned by a transmission asset owner in this part of the network, with duration ranging from a few days to several weeks.

In 2018, AEMO developed and published a new System Strength Requirements Methodology document under the National Electricity Rules. The methodology is applied to determine minimum system strength at transmission network nodes, sufficient to maintain overall power system security [2]. An indirect effect of this requirement is to ensure that the performance of the majority of IBG committed or installed by 1 July 2018 will not be deteriorated significantly below the level accepted under their connection arrangements.

Currently these requirements do not specifically account for the impact of prior network outage conditions, where a planned outage of a transmission line would further reduce the system strength available to IBG [3].

Figure 2 shows an actual measurement of the voltage at terminals of an IBG when a transmission line in the network was taken out of service for maintenance. This transmission line is along the corridor between an IBG and the rest of the network with a higher concentration of large synchronous generators. The frequency of these oscillations was approximately 7 Hz.

These sustained oscillations have not been shown to present a material risk to the broader power system (such as risk of cascading failure) in real time. However, they cannot be permitted because of the following key concerns:

- Excessive level of short-term flicker, which is larger than the maximum permissible level of 0.8 in IEC 61000.3.7 [4].
- Low or no level damping, falling short of the required damping ratio of 0.05 for the frequency of oscillations observed (7 Hz) required by National Electricity Rules.
Under certain system conditions, the observed level of short-term flicker results in \( P_{\text{st}} \) of above 1.0, which is above flicker planning standards as per IEC 61000.3.7.

This paper has presented a typical example of sustained post-fault oscillations due to a decline in the system strength available for IBG compared to system intact conditions as has been experienced in power system. Different experiences have been observed under system intact conditions, ranging from no post-fault oscillations at all to unacceptable levels only marginally lower than those observed in prior outage conditions. Due to these differences, IBG performance under system intact conditions is not discussed in detail as it varies significantly with local network conditions and the design and tuning of each IBG. General conclusions cannot be therefore reached.

The rest of the paper is organized as follows: Section 2 highlights the importance of using EMT-type simulation, and whether full-scale or reduced-order power system modelling should be used; Section 3 provides result of the analysis including various sensitivity studies carried out to identify key contributors to the observed network behaviours; and Section 4 discusses operational implementation of the findings, before conclusions are presented in Section 5.

2. Application of power system modelling and simulation to assess the impact of prior outages

2.1. Choice of simulation tools

Power system modelling and simulation studies were conducted to determine the interaction between multiple IBGs and the rest of the power system under these reduced system strength conditions. There are broadly two types of simulation tools being used by the industry for system security analysis; Root Mean Square (RMS) type and Electromagnetic Transient (EMT) type.

Figure 3 shows the extent to which each simulation platform can account for fast and slow control systems commonly used in an IBG [5]. Fast control of power electronic converters, which is a key contributor in determining the dynamic response during low system strength conditions, cannot be accurately represented in RMS simulation models. As an example, Figure 4 compares the dynamic response of an inverter-connected plant under low system strength conditions with the use of RMS and EMT models indicating a fundamentally different outcome between the two simulation platforms. The plant is exposed to the same contingency in both simulation platforms. Both tools have generic protection modelled, but response from underlying fast acting controllers can only be observed in EMT type simulation.

Considering the limitations of RMS-type models, a large-scale EMT model of the entire region under consideration, comprising several hundred busbars, was
and several hundred busbars is a non-trivial task. This is because of the complexities involved in integrating models from different equipment manufacturers that might run on different integration time-steps, the effort needed to build a large-scale network model in an EMT platform, and the processing time required. A reduced-order model of the network, focusing on immediate plant of interest, has therefore often been developed with equivalent sources representing the rest of the network. Key differences between the reduced-order and full-scale models are:

• In the reduced-order model, pseudo grids in the form of voltage sources behind equivalent Thevenin impedances are connected to the boundaries of the sub-region under consideration. This representation provides a high-level understanding of the network behaviour; it does not, however, capture the dynamics of the wider power system. The full-scale EMT-type model inherently accounts for all these system dynamics.

2.2. Full-scale vs reduced-order EMT-type simulation

Conducting a network-wide EMT-type simulation in a power system comprising a large number of IBGs developed and applied for the studies discussed in this paper. This model includes all existing synchronous plant and IBG in the network under consideration, as well as the wider network extending into nearby regions, to capture the dynamic response of these regions. However, it is noted that synchronous generators in the neighbouring regions are either too small or far from the network under investigation. Therefore, they will not provide any tangible system strength support to IBG in the network under consideration.

To ensure the accuracy of results obtained from this integrated model, the response of individual components and the overall system was validated against actual system disturbances captured by the high-speed monitoring (HSM) system, to the extent such data was available for the individual plant.

Figure 4 - Comparison between EMT and RMS type of simulation

Figure 5 - Reduced-order model – voltages at key IBGs
Other IBG to be less impacted in terms of system strength, as they are still connected to the rest of wider network.

This contingency was applied for the scenarios studied. For the power system configuration shown in Figure 1, a prior outage of the line between Bus 10 and 12 followed by forced disconnection of the line between Bus 1 and 2, due to a network fault, would result in a radial connection of all solar farms to the other side of the network which does not include any synchronous generators within a 600 km distance. However, these synchronous generating units are not often operated. The distance to the nearest baseload synchronous generating units is in excess of 1,000 km. Such a condition causes undamped post-fault oscillations across a broader network with a peak-to-peak magnitude of oscillations of approximately 1.5%, as shown in Figure 7.

Figure 7 demonstrates the adverse impact of a credible contingency in prior outage conditions on dynamic performance of nearby IBGs. Note that several other combinations of planned and forced outages of nearby transmission lines were identified resulting in similar undamped oscillations, albeit with slightly lower magnitude of oscillations.

3. Impact of Static Var Compensators (SVCs)

To determine the positive or negative contribution of SVCs on the level of oscillations observed, simulation studies were conducted with each of the SVCs at Bus 1 and 15 disconnected separately from the system. Simulation studies illustrated that removal of either of the SVCs has an insignificant impact on the level of oscillations. This is seen by comparing Figure 7 (with SVC) and Figure 8 (without SVC).

Note that the impact of disconnection of SVC at Bus 10 was not studied. This is because no oscillations
Figure 9 and Figure 10 show that reducing generation alone (i.e. keeping number of inverters online unchanged) from these solar farms was not found to mitigate these post-fault voltage oscillations appreciably, and that there is only a marginal reduction in the post-fault voltage oscillations for reduced dispatch levels alone. All individual inverters are connected to the network for simulation studies presented in this sub-section i.e. total number of inverters online remained unchanged.

3.5. Impact of disconnection of solar farms

To determine whether other network elements might have a significant contribution to the post-fault voltage oscillations, all solar farms were disconnected from the network with the same N-1-1 contingency applied. No post-fault oscillations were observed, as shown in Figure 11. This confirms solar farms as the key contributor to undamped post-fault voltage oscillations.

were experienced on this SVC for the simulation studies conducted, and because this SVC will remain connected to the wider power system and associated large synchronous generators.

3.3. Impact of nearby HVDC link

The change in DC link flow or disconnection of it, has not shown any impact on the magnitude or frequency of post-fault oscillations. Three levels of power flow – 0 %, 60% and 90% – were considered during this analysis and did not show any positive or negative impact on post-fault oscillations.

3.4. Impact of IBG dispatch level

Analysis was conducted to understand the impact of IBG generation output level on the magnitude and frequency of post-fault oscillations, individually and collectively.

Figure 7 - Post-fault voltage oscillations

Figure 8 - Post-fault oscillations at solar farm (SF) POCs with SVC out of service
3.6. Impact of reduced number of inverters

To analyse the effect of number of inverters connected to the grid, a sensitivity analysis was carried out by reducing the number of inverters connected to the grid. Figure 12 shows that reducing the number of on-line inverters results in a significant reduction in the level of post-fault oscillations experienced. The results in Figure 12 example were obtained when 55% of the inverters from each studied IBG were connected to the network.

Similar impact of solar and wind farms

The oscillations observed in this part of the network all involves solar farms, since all IBG impacted by the specific prior outage post-fault conditions happened to be solar plant.

For this particular outage, the wind farms in the area were connected to the wider network via a stronger connection, so their performance was not affected. Subsequent analysis, however, indicated similar contributions to post-fault oscillations from nearby wind farms for a prior outage of the line between Bus 5 and 7. Simulation studies also indicated that a substantial reduction in the number of online wind turbines connected between Bus 7 and 11 was required to reduce these post-fault oscillations.

4. Operational management of system security during a planned outage

In the Australian NEM, power system security is maintained with the use of constraints, which are applied via constraint equations to determine generation dispatch patterns and power flows that would maintain

![Figure 9 - Voltages at IBG POCs with generation at 50%](image1)

![Figure 10 - Voltages at IBG POCs with generation at 0%](image2)
5. Conclusions

This paper presented an approach implemented in practical power system operation for managing the impact of prior network outages in a large-scale power system with several nearby IBG. The network section under consideration is in a remote part of the power system.

This paper demonstrated that network prior outages would have a clear adverse impact on the response of IBG. Undamped voltage oscillations were observed following fault clearance under prior outage conditions. The magnitude of these oscillations under prior outage conditions was in the range of 1% to 5%, depending on the system conditions, with their frequency ranging from 5 to 10 Hz.

Figure 11 - Voltages at solar farm (SF) POCs with all solar farms disconnected

Figure 12 - Voltages at IBG POCs with reduced number of inverters

system security. Most constraints are for system normal conditions and for all credible contingencies. Additional constraints are usually applied to manage the impact of outages on system security [6]. A specific constraint is often developed for a specific contingency. The impact of this specific constraint could be a reduction in generation from a region or from a specific generating system, or flow on a transmission line or an interconnector.

To avoid the post-fault oscillations observed in the full-scale PSCAD model, AEMO developed a specific constraint that not only limits permissible output of all nearby solar farms, it will also limit the number of online inverters based on detailed power system studies. Prior to the commencement of an outage, this constraint is applied to determine optimal and secure dispatch.
This paper investigated the contribution of each IBG – including wind farms, solar farms, SVCs and an HVDC link – to sustained voltage oscillations. Simulation studies indicated that reducing the dispatch level of impacted IBG alone had an insignificant impact. It was demonstrated that a reduction in the dispatch level of IBG would only be effective if it also involves a reduction in the number of online inverters. The number of inverters online is the key factor that affects dynamic performance of the network.

The contingency discussed in the paper primarily impacted solar farms. However, similar levels of oscillations were observed on nearby wind farms for other prior outages which had a more pronounced reduction in the available system strength for the online wind turbines. A reduction in the number of online wind turbines was proven effective, as observed for solar inverters.

6. References


[4] IEC standards on Electromagnetic compatibility Part 3.7: Limits – Assessment of emission limits for the connection of fluctuating installation of MV, HV and EHV power systems, IEC 61000.3.7


Abstract
With a growing share of inverter-interfaced generation in modern power systems, synchronous inertia is declining. This leads to faster frequency drop after large generation trip events. During low inertia conditions, frequency containment reserves might not be sufficient to arrest frequency before it reaches the threshold for underfrequency load shedding. It is therefore becoming increasingly important for system operators to be able to assess frequency response in near real time. In contrast to detailed models, simplified models offer short simulation times and their parameters can be accurately identified and adapted to changing system conditions in near real time. In this paper, the parameters of governor response models are identified by minimizing the error residuals between the simulation models’ and the actual system’s measured active power response. This is accomplished by using historic event data from two system operators: the Electric Reliability Council Of Texas (ERCOT) and the Swedish Svenska kraftnät (Svk). Then, the respective frequency response models are simulated to assess frequency response. The results show that, despite their simplicity, the models provide a very good fit compared to the actual response. The models of ERCOT and Svk are examined; however, a similar approach can be employed to represent the frequency response of other power systems.

List of symbols
- \( t_{\text{dist}} \): Time of disturbance identified by RoCoF
- \( t_{\text{gen}} \): Time of disturbance identified by disconnected generator
- \( F(s) \): Transfer function for turbine and governor
- \( DB \): Deadband
- \( \Delta P_m \): Mechanical power change
- \( \Delta P_{m,\text{max}} \): Headroom
- \( \Delta P_{m,\text{min}} \): Legroom
- \( f(x) \): Cost function
- \( x \): Set of parameters
- \( m \): Total number of samples
- \( r \): Residual error
- \( g \): Modeled output
- \( y \): Measured output
- \( k \): Total number of events
- \( \Delta P_{\text{dist}} \): Size of disturbance
- \( H \): Inertia constant
- \( D \): Damping constant
- \( P_{\text{gov}} \): Governor request
- \( P_{\text{cap}} \): Unit capacity
- \( \Delta f \): Frequency deviation
- \( f_{\text{nom}} \): Nominal frequency
- \( E_p \): Droop
- \( T \): Time constant for ERCOT models
- \( K_p \): Proportional gain
- \( K_i \): Integral gain
- \( T_y \): Time constant for gate servo
- \( T_w \): Effective water time constant
- \( P_{\text{base}} \): Power base
- \( K_R \): Scaling parameter

List of abbreviations
- UFLS: Underfrequency Load Shedding
- RoCoF: Rate of Change of Frequency
- FCR: Frequency Containment Reserves

KEYWORDS
The ability of a power system to react to sudden change in load or generation is called frequency response. Frequency response in the first seconds after a disturbance consists of inertial response and governor response. Inertial response is the inherent release of rotational kinetic energy stored in the rotating masses of the synchronous machines to the grid, in response to sudden loss of a generator or load increase [2]. As a result, the synchronous machines are slowing down and the system frequency declines. Governor response corresponds to the adjustment of the power output of the generators right after the disturbance to arrest and stabilize the declining system frequency [3]. If governor response is insufficient, then the system frequency decline continues and may lead to underfrequency load shedding (UFLS) and cascading generation outages.

Since inverter-interfaced generation is rising and displacing conventional generation, the synchronous inertia is also decreasing. Assuming that the size of generation contingencies does not change significantly, this entails higher absolute values of Rate of Change of Frequency (RoCoF), which means faster frequency decline. In this case, Frequency Containment Reserves (FCR) might not be sufficiently fast to arrest frequency before it reaches the threshold for UFLS. Consequently, monitoring and assessment of frequency response constitutes a crucial task for the System Operators (SOs) [4]-[7]. To assess the frequency response of the system after a disturbance and design appropriate control schemes (e.g. UFLS [8], [9]), SOs monitor or estimate the inertia of the system and they also possess dynamical models that are able to represent the system’s behaviour. These models can be either detailed or simplified [10]-[12]. Simplified models consist of a low order dynamic equivalent of the power system that approximates system frequency behaviour. These models disregard potential synchronizing oscillations, as well as transmission system limitations. Despite the fact that they may lack detail, they can be developed particularly fast and with the minimum amount of resources, and they can also be available to the academic community. Furthermore, it has been shown that despite their simplicity, they can provide an accurate representation of the average frequency of the system [13]. Contrary to the detailed models, simplified models offer very short simulation times and allow real time assessment, such as real time evaluation of frequency response sufficiency.

Therefore, simplified models are employed in this study. The simulation times of the models are of utmost importance for frequency response assessment in real time. Consequently, the models that are selected are as simple as possible and do not follow the exact structure of typical simplified models that have been employed in the past [14]-[15]. As a result, even shorter simulation times can be achieved.

The development of simplified frequency response models has been considerably examined in the literature. An example is presented in [15], where a low order frequency response model is developed. The authors assume a system dominated with reheat steam turbine generators. Therefore, a typical reheat turbine governor model is employed to represent the whole system. However, this approach is not suitable for a power system with a fleet comprised of different generation types. In [16], a frequency response model is proposed that incorporates a UFLS scheme. It is considered that different types of generators participate in the generation mix. Each of these types is represented separately, by employing the same dynamical model but with different
parameters for each type. The parameters of each type are not identified, and typical values are used. However, as will be shown in this study, typical parameter values do not always represent accurately the frequency response of a system. In [17], a review of factors that affect the frequency response of a power system is presented. The different generation types are represented by separate and different dynamical models. Once again, the parameters are not identified based on historic events, but typical values are used. Finally, [18] presents a simplified frequency response model for the Electric Reliability Council Of Texas (ERCOT), which consists of two submodels: one for the steam and one for the gas turbine generators. The model parameters are tuned by employing Phasor Measurement Unit (PMU) data obtained from ERCOT. The submodel for the gas turbine generators represents both simple and combined cycle gas turbines. However, as will be shown in this study, simple and combined cycle gas turbines may have much different response and should be represented with different submodels.

In this paper, a bottom-up approach is followed to assess frequency response. First, a method to identify the parameters of the governor response models of the dominant generation types of a power system is proposed. The identification is achieved by employing measurements from historic events. The measurements used in this study are obtained from the power systems of Texas and Sweden. After their parameters are identified, the governor response models of each system are gathered together to form a frequency response model. This model can then be simulated to provide frequency response assessment for any past or future event for the respective power system. An advantage of this approach is that the same methodology is applicable to any power system. The results from the case study show that the models and their parameters can differ between different power systems and different generation types. The models are implemented in Simulink® and the simulations along with the parameter identification are implemented in MATLAB®.

After the introduction, Section 2 presents the methodology of governor parameter identification. Section 3 presents the case study, which includes an analysis of the dominant generation types of the two examined power systems. Section 4 presents the results of the case study, while Sections 5 and 6 present the discussion and the conclusion respectively. Finally, Section 7 describes some lessons that were learned from this study along with actions that should be taken in the future and Section 8 contains the acknowledgement.

### 2. Methodology

The different tasks of the method for identifying the parameters of the governor models are summarized in Figure 1. The tasks can be separated in three main parts: i) data processing, ii) dynamic models and, iii) parameter identification. During the implementation of the method, each part should be completed before moving to the next one. Data processing includes all actions that should be taken when data (i.e. measurements) become available. After data processing is finalized, the dynamic models and their features are selected. Finally, since the models and their inputs/outputs have become available, the parameter identification algorithm can be applied. It has to be mentioned that this method can be used at system level to identify the parameters of aggregated models of different generation types, but also at bus level to identify the parameters of the governor of a single unit.

#### 2.1. Data processing

Initially, the time of the disturbance $t_{\text{dist}}$ should be identified. This is achieved by setting a RoCoF threshold based on event analysis. The $t_{\text{dist}}$ is defined as the time when RoCoF falls below the set threshold. However, if power measurements are available, the time of disturbance can also be identified by the measurements of the respective disconnected generator ($t_{\text{gen}}$). It is possible that $t_{\text{dist}}$ and $t_{\text{gen}}$ are different due to time delay between frequency and power measurements. This time delay can be attributed to the time that it takes for the event to spread in the system, but also to the time it takes for different measuring devices to sense and transmit their measurements (i.e. communication delay). Some means is necessary to identify this time delay and the measurements should be shifted accordingly, so that $t_{\text{dist}}$ and $t_{\text{gen}}$ coincide.

Furthermore, the dominant generation types should be identified, so that their governors (and their turbines) can...
be modeled. For this purpose, the total online capacity of the different generation types for the different events should be examined. The dominant generation types are considered to be the ones that provide governor response and also have high total online capacity. In addition, the headroom/legroom of these dominant generation types should be calculated, since they are used in the modeling process to limit the power output.

2.2. Dynamic models

After data are processed, the dynamic models that represent the governors and the turbines of the dominant generation types should be selected. Each model represents an equivalent model for governor response for each dominant generation type. A depiction of such a model is presented in Figure 2. In this figure, \( F(s) \) represents the governor and the turbine. The input of the model is the frequency deviation, which is limited by the deadband (\( DB_{\text{max}} \) and \( DB_{\text{min}} \)). The deadband is the frequency deviation range around nominal frequency for which the governor does not react. The output of the model is the mechanical power change (\( \Delta P_m \)) and it is limited by the headroom (\( \Delta P_{m,\text{max}} \)) and the legroom (\( \Delta P_{m,\text{min}} \)).

As depicted in Figure 2, except for the parameters to be identified (which are included in \( F(s) \)), these models have some other parameters that should be defined, too. These are the deadband and the headroom/legroom limits.

![Figure 2: Simplified representation of a governor response model.](image)

The deadband is defined according to the grid code of the corresponding power system. The headroom/legroom limits have been identified in the data processing task. The output of the governor model is limited by the aggregated headroom and legroom of all generators of respective type. It is recognized that the actual response depends on how close each individual generator unit is operating to its upper or lower limit. However, it is assumed that aggregating headroom/legroom does not significantly affect the accuracy of the method.

Moreover, the time frame of interest for the parameter identification should be defined. This extends from \( t_{\text{dist}} \) to a selected time point after \( t_{\text{dist}} \). The time frame of interest should not be too short, in the sense that it should include the frequency nadir, as well as a significant or even a full amount of governors’ response. However, it should not be too long either, since it should not include time ranges that are not of interest for this study. More discussion about the time frame of interest follows in the next section, where the case study is presented.

2.3. Parameter identification

To begin with, the initial values and the limits of the parameters to be identified should be selected. This can be done based on historic event analysis of the corresponding power system. For example, such values for the Nordic power system can be obtained from [5]. Furthermore, the input and the output of the model (and of the identification process) should be defined. In this case, since the identification concerns governor response models, as depicted in Figure 2, the input is the frequency deviation and the output is the change in the aggregated power output summed over all generators of each type.

Before the application of the optimization algorithm that minimizes the residual errors between the models’ and the actual system’s measured active power response, the algorithm’s stopping criteria should be defined. There are three stopping criteria that are considered. These are the maximum number of iterations, the step tolerance (lower bound on the size of a step between optimization iterations), and the termination tolerance on the function value (lower bound on the change in the value of the objective function during a step). The values that are assigned to these stopping criteria should guarantee that the algorithm provides accurate results within reasonable time.

Finally, the optimization algorithm is applied. In order to identify the unknown parameters, the simulated output of the model of each generation type is trained to fit the actual change in power output for each generation type, which is retrieved from the data of each event. For this purpose, the sum of the squared residual errors between simulated
and actual output is minimized by employing the non-linear least-square solver from MATLAB lsqlin [19]. The non-linear solver is selected rather than a linear one, because of the existing non-linearity that the headroom/legroom and the deadband limits introduce. Since the parameters to be identified are constrained, the Trust-Region-Reflective algorithm is employed. This algorithm approximates the cost function $f(x)$ with a simpler function that reflects its behaviour in a trusted region around the current set of parameters $x$ [20]. In this way, the obtained parameters are optimized for each event. The equation that governs this problem is:

$$\text{minimize } f : \quad f(x) = \sum_{i=1}^{m} r_i(x)^2,$$

where $r_i(x) = g_i(x) - y_i$,

and $x$ is the set of parameters to be identified, $i$ stands for the samples in the selected time period, $m$ is the total number of samples, and $r_i$, $g_i$, and $y_i$ are the residual error, the modeled output, and the measured output at time $i$, respectively. An example of the residual errors before and after the optimization is depicted in Figure 3.

The optimization can be applied to either each event separately - as is the case for Figure 3, where (1) has been used - or to all examined events simultaneously. If it is applied to all events simultaneously, then the aggregated sum of the residual errors is minimized:

$$\text{minimize } f : \quad f(x) = \sum_{j=1}^{k} \sum_{i=1}^{m} r_{ij}(x)^2,$$

where $r_{ij}(x) = g_{ij}(x) - y_{ij}$,

and $j$ is the event number, $k$ is the total number of events, and $r_{ij}$, $g_{ij}$, and $y_{ij}$ are the residual error, the modeled output, and the measured output of event $j$ at time $i$ respectively.

In case that more or less emphasis is required to be added on a specific event in a simultaneous optimization, then its residual errors can be multiplied by a selected weight (i.e. a positive number). Similar approach should be followed if more or less weight should be added to a certain time period of an event.

If the optimization is applied to each event separately, then one set of parameters is obtained for each event. This means that this set of parameters can be used only for this particular event or only for similar operational conditions. On the other hand, it would be more efficient and practical to the SOs if one common set of parameters is obtained for all events. The accuracy of such a set would be compromised, since it would represent all examined events simultaneously. However, with one common set of parameters obtained, the governor response for each - historic or even future - event can be tuned by just changing parameters that are available in the control room around the clock (e.g. capacity, headroom).

Even if the accuracy of such a set is satisfying, it represents the governor - and not the frequency - response of the system. Since the main objective is to assess the frequency response of the system, a frequency response model should be employed. Such a model is depicted in Figure 4 and it consists of a closed-loop model with negative feedback. In this model, the i dominant generation types of a power system are represented with their respective governor response model $F_i(s)$, which includes the parameters that have been identified by the aforementioned process. The power output of each of the dominant generation types is then summed to provide
and a part of the Danish power system to form the Nordic Power System (NPS). The nominal frequency of NPS is 50 Hz and its peak load is 70 GW [22]. ERCOT and NPS have very different topology, as well as a different mix of load and generation. However, they also have similar characteristics that render them ideal for this study. ERCOT and NPS are not synchronously connected to any other power system. Therefore, they do not receive any external support regarding frequency response. Furthermore, both systems have a peak load around 70 GW and experience a significant amount of inverter-interfaced generation in their generation mix. These characteristics increase the vulnerability of these systems in terms of frequency stability. Therefore, it becomes essential to both SOs to be able to simulate frequency events easily in near real-time and with sufficient accuracy, by employing appropriate frequency response models.

The source for both groups of data is the Supervisory Control And Data Acquisition (SCADA) of the two operators. However, there are some differences between the retrieved data. Data from ERCOT’s SCADA system are retrieved every 2 seconds. Data provided for this study include power output measurements of each generator from six historic underfrequency events. The month and time of each event are also available for this study. On the other hand, the Swedish data are retrieved from SCADA system every 1 second. Data provided include frequency and power measurements. However, observability is limited, since measurements from only 15 power plants are available for this study. Data from two events are available from Svk. However, their date and time are unknown.

For ERCOT, a frequency measurement at a single geographical location for the entire system and for each event is available. Due to the topology of ERCOT’s system there are no significant variations in frequency between different locations. For Svk, the frequency measurements that are available for each event come from 15 power plants, which are located close to each other. Hence, no significant variations are observed between the frequency measurements of these plants. The average of these measurements for each event is calculated to constitute the frequency signal for this study. In NPS, there can be significant variations in frequency measurements from distant locations.

\[ \Delta P_m \] The deadband and the headroom/legroom limits for each generation type are already obtained, as has already been discussed. However, the size of disturbance \( \Delta P_{\text{dist}} \), inertia constant \( H \), and damping constant \( D \) are not identified. These values - marked with red in the figure - should be available to the SO. If this is not the case, then the worst case scenario can be considered, which includes the highest \( \Delta P_{\text{dist}} \) and the lowest system values for \( H \) and \( D \). If for the worst case scenario, frequency nadir is above the UFLS threshold, then it will also be above the threshold for any other scenario and the secure system operation can be guaranteed.

The process of assessing the frequency response of a power system with this method can be summarized as follows:

- The parameters of the governor and the turbine of each of the dominant generation types are identified,
- The values for \( \Delta P_{\text{dist}}, H, \) and \( D \) are selected,
- The frequency response model is simulated by having \( \Delta P_{\text{dist}} \) as input and \( \Delta f \) as output. By the output of the simulation, the frequency response and hence the frequency nadir are assessed.

![Figure 4: Simplified representation of frequency response dynamic equivalent model.](image)

3. Case study

The historic frequency event data that are used in this paper are retrieved from the two power systems operated by ERCOT and Svenska kraftna¨t (Svk). However, the same approach can be followed for data from any power system. ERCOT is responsible for 90% of the electric load of Texas, with peak load 74.5 GW [21] and nominal frequency 60 Hz. Svk is responsible for the reliable operation of the Swedish power system, which is synchronously connected to the Norwegian, Finnish
Therefore, a better observability with regard to frequency would be beneficial. Unfortunately, however, only these measurements were available for this study.

The time resolution of the available measurements is quite low, since PMU measurements were not available and SCADA measurements are used. However, it usually takes from 10-30 seconds for the governors to provide full response. Therefore, 1-2 seconds resolution is considered sufficient to fit the measurements and obtain the model parameters.

In order to identify $t_{\text{dist}}$ in the frequency measurements, a RoCoF threshold is employed for both ERCOT and Svk data. The $t_{\text{dist}}$ is defined as the time when RoCoF falls below the threshold. The RoCoF is calculated by first using the built-in MATLAB function diff, which calculates the difference between adjacent frequency measurements and then, the result is divided by the time step (2 s for ERCOT and 1 s for Svk). The threshold for both ERCOT and Svk is defined to be $-0.005$ Hz/s, based on event analysis. The analysis for ERCOT is depicted in Figure 5b. Similar behaviour was observed for Svk. Since electric power measurements from the generators are available, the net effect of both inertial and governor response is included. However, these two different kinds of response cannot be distinguished using the measured data. Furthermore, the power contribution from inertial response is quite short with regard to time in comparison to governor response. Therefore, in this paper, it is assumed that the electrical power measured is equal to the mechanical power, which is associated with governor response.

### 3.1. ERCOT: studied frequency events

The frequency and the RoCoF of the studied events along with their month and time are depicted in Figure 5a and Figure 5b. ERCOT has a diverse generation fleet, comprised of Simple Cycle Gas Turbines (SCGTs), Combined Cycle Gas Turbines (CCGTs), Steam Turbines (STs) (gas steam and coal/lignite), Wind Turbines (WTs), Solar, Hydro Turbines (HTs), Nuclear, and some other power sources (power storage, High Voltage Direct Current (HVDC) links, reciprocating engines). The vast majority of the generation capacity comes from SCGT, CCGT, ST, WT, and Nuclear. This is depicted in Figure 6, where the share of each generation type of the total online capacity is presented for each event.

All generators in ERCOT (except for the nuclear) are required to provide governor response in case of a disturbance. In order to examine the response of the dominant types, SCGT, CCGT, ST, and WT, the aggregated power output summed over all generators of each type for each event is depicted in Figure 7. The time points of the generator disconnection ($t_{\text{gen}}$) are aligned at 0 seconds on the figure for the purpose of comparison.

Since the share of each generation type differs for each event, it is impossible to provide comparable governor response plots without normalization. Therefore, 1 pu on the figure corresponds to the aggregated power output...
3.3. Dynamic equivalent models

As has been mentioned, the generation types that are modeled are SCGT, CCGT, and ST for ERCOT and HT for Svk. Each model represents an equivalent model for governor response for each generation type. The equivalent governor model includes time constant(s) to represent the dynamics of the governor and the turbine. The response of the governor is determined by the deadband and by the droop. In ERCOT, the generators are required to have a deadband of at most ±17 mHz [18], [21]. In Svk, the corresponding deadband is of at most ±10 mHz [23]. The governor droop defines how much additional power will be provided by the governor in response to the frequency deviation. Thus, when frequency deviation is outside the deadband, the governor response request is calculated according to the following equation [24]:

\[
P_{\text{gov}}(t) = -P_{\text{cap}} \left( \frac{\Delta f(t) - DB}{f_{\text{nom}}} - \frac{E_p}{f_{\text{nom}}} DB \right)
\]

(b) Aggregated response from dominant generation type.

Figure 7: Aggregated response from dominant generation types - ERCOT.

3.2. Svk: studied frequency events

The frequency of the studied events for Svk is depicted in Figure 8a. The main power sources are nuclear and HT, however governor response is mostly provided by HT and this is the generation type that is modeled in this study. As has been mentioned, power output measurements from 15 HT power plants are available and constitute the response that is modeled. This response for the two events is depicted in Figure 8b. As in Figure 7, the measurements are normalized and the beginnings of the events are aligned. The time alignment in Figure 8b is done based on \(t_{\text{dist}}\) since there is no information available about the time of the generator disconnection \(t_{\text{gen}}\) in the power measurements. However, it is apparent that since there is a time delay between the different measurements and events, this alignment is not ideal. More information about measurement time delay and alignment follows in the next subsections.

Figure 8: Svk events.
where \( P_{\text{gov}}(t) \) is the governor request in MW, \( P_{\text{cap}} \) is the unit capacity in MW, \( \Delta f(t) \) is the frequency deviation in Hz, \( DB \) is the deadband in Hz, \( f_{\text{nom}} \) is the nominal frequency in Hz and \( E_p \) is the droop in pu, with power and frequency base equal to \( P_{\text{cap}} \) and \( f_{\text{nom}} \) respectively. DB corresponds to either DBmax or DBmin depending on the sign of the frequency deviation.

The response of the unit to this governor request is defined by the unit’s dynamic behaviour. This case study examines the response of the turbines in the first 20 seconds after the disturbance. This time region has been selected, since the frequency nadir occurred within 20 seconds in all of the events. Furthermore, by that time, the governors for all generation types would have provided either a significant or even a full amount of their response.

### 3.3.1. SCGT

The modeling of the dynamics of the gas turbines has been thoroughly studied in the past [25], [26]. Gas turbines are equipped with acceleration, speed, airflow and temperature control. As is discussed in [18], it is reasonable to omit these controls from the modeling for the studied time frame and the stiffness of this specific examined power system, except for the speed control. Speed control includes the regulation of fuel supply, which depends on the frequency. Therefore, in [18] and [26], the authors introduce a function that represents the decline of power output due to less fuel supplied, in case that the frequency is reduced.

However, in this study such a behaviour has not been observed in any of the events. In Figure 7, it is apparent that the response of the gas turbines is positive directly after the moment of the disturbance. The reason that the decline of power is not observed could be due to 2 s resolution of the available measurements, such that the power drop due to fuel supply decline happens in-between the available data points. Another reason could be that the decrease in the rotational speed is compensated by adjusting the air inlet vanes. Since this behaviour is not observed in any of the events, it has not been included in the model. Thus, the dynamics of the governor and the turbine are approximated with a first-order response and are represented with a single time constant \( T \), as is depicted in Figure 9.

### 3.3.2. CCGT

In CCGT, the ST usually does not provide governor response and hence it can be omitted from the model [18]. Therefore, the model for CCGT can be the same as the one for SCGT and is depicted in Figure 9. The reason that these two generation types (SCGT and CCGT) are examined separately is that their parameters can differ substantially. Since the ST does not provide governor response, only the part of capacity corresponding to SCGT is taken into account in \( P_{\text{cap}} \) for CCGT.

### 3.3.3. ST

ST generation type contains the gas steam and coal/lignite turbines. Their modeling has also been examined in the past [3], [27]. For the purpose of this study it is reasonable to omit the slow dynamics of the boiler for ST and just consider the dynamics of the turbine [18]. Therefore, the model for the ST is also presented in Figure 9, where a single time constant \( T \) represents the dynamics of both the turbine and the governor.

### 3.3.4. HT

The model for HT is a simplified version of the one presented in [11] and it is depicted in Figure 10. In this case, the governor includes a PI controller (proportional gain \( K_p \) and integral gain \( K_i \)) and the dynamics of the gate servo, with a time constant \( T_w \). The time constant \( T_w \) represents the effective water time constant [11].

It has to be mentioned that the hydro turbines possess the non-minimum phase property. This physically means that when opening the guide vane after the disturbance to increase the inflow (so that the power output increases), the water pressure initially drops. Hence, due to that water pressure drop, initially the power output slightly decreases and then increases. Such a behaviour can be observed in Figure 8b for both events, even though there seems to be a time delay between the measurements. The power starts decreasing at 5 and 3 seconds for Events 1
and 2 respectively and then increases after a couple of seconds.

\[ \Delta f = \frac{K_p}{T + \frac{1}{s}} \]

\[ P_{out} = \frac{K_i}{T} \]

\[ P_{out} = \frac{K_p T_i}{s} \]

\[ \Delta P_{in} = \frac{K_p T_i}{s} \]

\[ \Delta P_{in, max} = \frac{K_p T_i}{s} \]

Figure 10: Simplified model for HT for SvK.

3.4. Time delay in the measurements

3.4.1. ERCOT

Unfortunately, the power measurements from different types of generation have different amounts of time delay. For example, in Event 1, a ST is disconnected and SCGT and CCGT start increasing their power output a couple of seconds before the disturbance is observed in the ST power output data. In order to train the models, power measurements from different generation types are aligned so that the time is zero when the generators start responding to the disturbance by increasing their output. This can be observed in Figure 7.

Additionally, there is also time delay between historical frequency and power measurements. Therefore, after the power measurements are aligned between each other, they are also aligned to the frequency measurements, so that \( t_{dist} \) coincides with \( t_{gen} \) and both of them coincide with time zero. In this way, the response of the generators is observed right after the frequency starts decreasing. However, this renders impossible the observation of the effect of the deadband on governor response. Therefore, the deadband is omitted from the model identification and validation stages.

The alignment of the frequency and power measurements is depicted in Figure 11a. The figure depicts Event 1, but the same procedure is followed for the rest of the events.

3.4.2. SvK

The information that is available for the measurements from SvK is limited. The \( t_{dist} \) is identified based on RoCoF, but there is no information regarding the time when the generator is disconnected. Therefore, there is uncertainty about the amount of time delay between frequency and power measurements. Figure 8b shows that there is substantial time delay, since the power output starts to increase only after about 3-5 seconds for both events. The frequency and power measurements have been aligned similarly to ERCOT. Time zero for the power measurements is assumed, when the non-minimum phase property of the HT is visible. Figure 11b depicts the frequency and power measurements for both events after the alignment. Since power measurements are manually aligned to frequency measurements the deadband is omitted from the identification and validation stages.

Figure 11: Time alignment of measurements.

3.4.3. Parameter identification

The proposed models include various parameters. Some of them are available from the measurements and a few of them are unknown. In the ERCOT models (Figure 9), the unknown parameters are the time constants \( T \) and the droops \( E_r \) for various generation types. On the contrary, the capacity of the specific generation type \( P_{cap} \) and the headroom/legroom are known. In the SvK HT model (Figure 10), the same parameters are available. However, since the HT model is slightly more complex than the model for ERCOT’s generation types, in this case there are more unknown parameters: the proportional gain \( K_p \), the integral gain \( K_i \), the time constant \( T \) for the gate
For both models, the input (frequency deviation) and the output (change in the power output of the respective generation type) are available through the measurements. Since the input of the models is the frequency deviation ($\Delta f$), the frequency is subtracted from the nominal frequency $f_{\text{nom}}$. The nominal frequency for each event is the frequency at $t_{\text{dist}}$. Hence, $\Delta f$ (in per unit) is used as input to the model, it passes through the governor and the turbine and it is then multiplied with $P_{\text{cap}}$ to provide the output in MW. The model output is the sum of the change in power output of all generators that belong to the respective generation type.

As has been mentioned, there are three stopping criteria for the optimization algorithm. All three stopping criteria are assigned their default values, since with these values the algorithm provides accurate results and within reasonable time. The stopping criteria are and their assigned values are depicted in Table II.

<table>
<thead>
<tr>
<th>Stopping criterion</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum number of iterations</td>
<td>400</td>
</tr>
<tr>
<td>Step tolerance</td>
<td>1e-6</td>
</tr>
<tr>
<td>Termination tolerance on the function value</td>
<td>1e-6</td>
</tr>
</tbody>
</table>

4. Results

4.1. ERCOT

Before the optimization, the unknown parameters have to be initialized and their limits should be specified. The initial values for $T$ and $E_p$ are selected to be 2 seconds and 5% for all ERCOT models. These values are selected as they constitute typical used values for time constant and droop respectively. Different initial values have been also tested, but the final results did not change.

The limits for the droop have been specified based on historic performance analysis and are 4-12%. Since the response time varies between different events due to the difference in unit commitment, as depicted in Figure 7, the limits for $T$ have been defined to be from 0-20 seconds. It has to be mentioned that the limits can vary for different power systems, since the quantity and the time of the response significantly vary.

The proposed model for each generation type is validated for the 6 events that are available. The results of this validation are presented in the next paragraphs. In general, it is considered that the modeled response accurately fits the measured one if the absolute residual error for each point is not substantial (i.e. does not exceed 10%, when it is scaled by the measured response at 20 seconds).

4.1.1. SCGT

The results of the SCGT model validation are presented in Figure 12. The model presents a very good fit, especially considering its simplicity and the fact that the time step between the available measurements is quite long (2 seconds). The only case where the fit is not very accurate is Event 4, due to some oscillations in the measured response that were not apparent in the frequency signal and hence, could not be captured by the model.

The obtained parameters along with the SCGT capacity and headroom are presented in Table III. It has to be mentioned that, in Tables III-V, capacity and headroom are not identified parameters, but they are instead extracted from the available measurements. The obtained values for $E_p$ and $T$ are significantly higher than the typical values for such parameters. However, these values totally agree with the behaviour that is observed in Figure 12.
4.1.4. Obtain a common set of parameters

The previous section shows that it is possible to represent the governors and turbines of various generation types of ERCOT with a simplified dynamic equivalent model. However, the parameters are obtained from each event’s measurements separately. It would be more efficient and practical to the SO if one common set of parameters could be obtained for all events. Then, the governor response for each - historic or even future - event could be tuned by just changing parameters that are available in the control room around the clock (e.g. capacity, headroom). In this way, the SOs could estimate the frequency response to any future disturbance by only using these available parameters.

To obtain a common set of parameters, a simultaneous optimization for all six events is implemented. The results of this optimization are presented in Figures 15-17 and in Table VI. Regarding SCGT, the model fits well the measured data considering that a common set of parameters is employed for all events. However, the accuracy is not that high for all events when CCGT and ST are examined, especially for Event 4. Event 4 is the one with the greatest share of WT, however WT
do not provide any governor response for this particular event according to Figure 7. Hence, the other generation types provide more response to cover for WT. In the simultaneous optimization, the response from CCGT and ST is underestimated (Figure 16 and Figure 17). Since the accuracy for the other events is better, it means that for a particular value of frequency deviation, the response for this event was greater, compared to the others. This can be verified in Table IV and Table V, where the value of $E_p$ is significantly smaller for Event 4.

The previous result is significant, since it drives towards the development of a universal model that can express any event. However, it should be noted that the results are based on only six events and could possibly vary if more events were examined.

![Figure 15: ERCOT: Fitting results for SCGT - Simultaneous optimization.](image1)

Figure 15: ERCOT: Fitting results for SCGT - Simultaneous optimization.

![Figure 16: ERCOT: Fitting results for CCGT - Simultaneous optimization.](image2)

Figure 16: ERCOT: Fitting results for CCGT - Simultaneous optimization.

![Figure 17: ERCOT: Fitting results for ST - Simultaneous optimization.](image3)

Figure 17: ERCOT: Fitting results for ST - Simultaneous optimization.

Table VI - ERCOT: Identified parameters for SCGT, CCGT and ST - Simultaneous optimization.

<table>
<thead>
<tr>
<th>Type</th>
<th>$T_s$ (s)</th>
<th>$E_p$ (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SCGT</td>
<td>7.9</td>
<td>9.1</td>
</tr>
<tr>
<td>CCGT</td>
<td>8.7</td>
<td>11.9</td>
</tr>
<tr>
<td>ST</td>
<td>6.9</td>
<td>12</td>
</tr>
</tbody>
</table>

4.1.5. Frequency response assessment

So far, this part of the case study has focused on accurately identifying the governor parameters. Despite the fact that this information can be valuable for the SOs, it only serves as the first step in creating a model to assess the system’s frequency response, which is the main goal of this study. Towards this goal, a closed-loop simulation of the system should be implemented. The simulation model for ERCOT is presented in Figure 18a.

Each of the blocks SCGT, CCGT, and ST contains the model from Figure 9 along with the identified parameters from Table VI. The Power Storage and the WT blocks contain the time series of the measured power response of ERCOT's power storage and WT respectively for each event. Since a model for power storage has already been available from ERCOT, this has not been a part of this study. Simulations with and without WT have been performed to reveal the importance of modeling this type of generation in the future. Finally, $H$ (inertia constant), $D$ (estimated load damping) and $\Delta P_{\text{dist}}$ (size of disturbance) are provided from ERCOT for each event.

Each of the SCGT, CCGT, and ST blocks contains the parameters that have been obtained from the simultaneous optimization that has been implemented in the previous subsection. The input of the blocks is the frequency deviation in pu and their output is the power response in MW, due to the multiplication with
still considered to be satisfactory. Finally, in case that the model response deviates, since SOs have to plan for the worst case scenario, it is important for the simulation to provide pessimistic results, i.e. lower frequency nadir, than in reality, which is the case for all examined events.

In Events 3 and 4, the modeled frequency nadir with WT is lower than the one without WT. This is explained by the fact that, for these two events, the power output from WT decreases after the disturbance instead of increasing. It has also to be mentioned that the values of $H$ and $D$ affect the result substantially. A small error in these values can cause a significant error in the estimation of the frequency nadir. Since there is no further information about the accuracy of $H$ and $D$, no comments can be made regarding the correlation between identified parameters and error of the estimated frequency nadir.

### 4.2. Svk

#### 4.2.1. Separate and simultaneous optimization

Several parameters of the units, from which the measurements are provided, are not available in this study. These include headroom/legroom, as well as the capacity of the units. Hence, the headroom/legroom limit is removed from the model in Figure 10. Furthermore, the total power output of the units at $t_{\text{dist}}$ stands for $P_{\text{cap}}$ in the model, since no information about the capacity is available.

Regarding the initialization and the limits of the unknown parameters for the optimization, information from [10] and [11] is used. The initial values and the limits of the parameters are presented in Table VII. The proposed model is validated for the 2 events that are available. A separate optimization is realized for these events and its results are presented in Figure 19a and Table VIII.

Closed-loop simulations have been performed for all ERCOT’s events and they are presented in Figure 18b. In order to assess the importance of WT’s contribution, the results have been plotted with and without the addition of the time series of the measured WT response. The inclusion of the WT measurements does not affect the result significantly. Even without the WT measurements, the absolute error of frequency nadir is quite low. It has to be highlighted that the parameters for SCGT, CCGT, and ST models are the ones obtained from a simultaneous optimization for all events. Therefore, the worst estimation result, which is a 0.017 Hz difference in frequency nadir for Event 1, is still considered to be satisfactory. Finally, in case that the model response deviates, since SOs have to plan for the worst case scenario, it is important for the simulation to provide pessimistic results, i.e. lower frequency nadir, than in reality, which is the case for all examined events.

In Events 3 and 4, the modeled frequency nadir with WT is lower than the one without WT. This is explained by the fact that, for these two events, the power output from WT decreases after the disturbance instead of increasing. It has also to be mentioned that the values of $H$ and $D$ affect the result substantially. A small error in these values can cause a significant error in the estimation of the frequency nadir. Since there is no further information about the accuracy of $H$ and $D$, no comments can be made regarding the correlation between identified parameters and error of the estimated frequency nadir.

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Regarding the initialization and the limits of the unknown parameters for the optimization, information from [10] and [11] is used. The initial values and the limits of the parameters are presented in Table VII. The proposed model is validated for the 2 events that are available. A separate optimization is realized for these events and its results are presented in Figure 19a and Table VIII.
and, hence, one common set of parameters is obtained. The results of this optimization are depicted in Figure 19b and Table IX. As expected, the model fits well the measured data. Since one common set of parameters is obtained, it can be used along with different $P_{cap}$ and $Δf$ to represent any event. It should be noted that the results are based on only two events and could possibly vary if more events were examined.

Table IX - Svk: Identified parameters for $ht$ - Simultaneous optimization

<table>
<thead>
<tr>
<th>$K_s$ (pu)</th>
<th>$K_s$ (s$^2$)</th>
<th>$E_p$ (%)</th>
<th>$T_f$ (s)</th>
<th>$T_x$ (s)</th>
<th>$P_{cap}$ (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.6</td>
<td>0.67</td>
<td>2</td>
<td>0.85</td>
<td>0.44</td>
<td>1232</td>
</tr>
</tbody>
</table>

4.2.2. Frequency response assessment

Similar to ERCOT, a closed-loop simulation with the obtained parameters from the simultaneous optimization - presented in Table IX - is also implemented for Svk. In this way, the frequency response and nadir can be assessed. A challenging issue for this kind of simulation for Svk is that power measurements from only 15 power plants are available. There is no additional information regarding how many other responsive power plants are in the system and how much they respond for each event. This means that the response from the 15 power plants cannot be scaled according to some available measurement, so that the total power response for each event is obtained.

To solve this issue, a scaling parameter ($K_p$) is added in the closed-loop simulation model. $K_p$ can be interpreted as the amount of total responsive generation over the amount of the available responsive generation. In this study, this parameter is tuned by trial and error, so that the modeled frequency response follows the measured one. It is acknowledged that this approach cannot be employed for the prediction of the frequency nadir in the control room of a SO. However, it is expected

Table VIII - Svk: Identified parameters for $ht$ - Separate optimization for each event.

<table>
<thead>
<tr>
<th>Event</th>
<th>$K_s$ (pu)</th>
<th>$K_s$ (s$^2$)</th>
<th>$E_p$ (%)</th>
<th>$T_f$ (s)</th>
<th>$T_x$ (s)</th>
<th>$P_{cap}$ (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>3.6</td>
<td>0.70</td>
<td>2</td>
<td>0.42</td>
<td>1232</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>5.2</td>
<td>0.67</td>
<td>2</td>
<td>0.44</td>
<td>1177</td>
<td></td>
</tr>
</tbody>
</table>

Similarly to the results for ERCOT, the proposed model provides a good fit and the obtained parameters do not vary substantially. Therefore, it is interesting to examine how the model fits the measured data, when the model parameters for both events are optimized simultaneously.
that SOs will have adequate information regarding the total responsive generation and therefore, it will not be necessary to estimate it.

The closed-loop simulation is performed for both events. In the closed-loop simulation model, all variables and parameters are in pu. The values of $H$ and $\Delta P_{\text{dist}}$ are provided by Svk for each event. No information about $D$ has been made available, so it was set to 2%, based on past event analysis. The results from the closed-loop simulation are presented in Figure 21. Initially, the simulations are performed with the $H$ values that are provided by the SO and with the disturbance considered to be a step. As is shown in the figure, the results are not satisfactory. However, from the figure, it seems that the disturbance should be treated as a ramp, rather than as a step. This conclusion is deduced by the curved behaviour that the frequency deviation presents in the first moments after time is equal to 0. Furthermore, the value of $H$ that is provided seems to be smaller than the one that would accurately fit the measurements. Therefore, the simulations are performed again, with the disturbance treated as a ramp and with the value of $H$ tuned so that the modeled and measured frequency response coincide in the first couple of seconds.

If ramp disturbance and adjusted value of $H$ are considered, the error between measured and modeled frequency nadir is negligible. On the other hand, if step disturbance is considered and the $H$ value is not adjusted the absolute error for the frequency nadir is 0.058 Hz and 0.127 Hz for Event 1 and 2 respectively. This result exposes one of the main disadvantages of this method: the values of $H$, $\Delta P_{\text{dist}}$ as well as $D$ - which are not included in the parameter identification process - affect substantially the frequency nadir estimation.

5. Discussion

This paper proposes the identification of governor models' parameters by employing actual historic event data from ERCOT and Svk. Open-loop models are used to identify the parameters of the governors, while closed-loop models are employed to assess the frequency response. Separate optimization for each event is used to examine the quality of the model selection. Furthermore, simultaneous optimization is employed to identify one set of parameters that can represent all examined events.

Several challenges have been identified along this study. Time delay between the several measurements renders the identification of the parameters a challenging task. In this work, the time delay is removed by shifting and aligning the measurements. Another option would be to add the time delay as an unknown parameter to be identified. However, this approach provides greatly different values for time delay between the events, which is unrealistic. Furthermore, the addition of time delay as a parameter to be identified increases the uncertainty of the obtained value for the time constant, since these two parameters are correlated.

The obtained values for the time constant parameters for ERCOT are much larger than typical values that are proposed in the past [26], [27]. This is attributed to the fact that the time constant in this study contains the dynamics of the whole generator and does not represent solely the turbine. Additionally, the rather slow response that is observed strengthens the validity of the obtained time constants. Similarly, the obtained values for droop for ERCOT are higher than the requirement (i.e. 5 %). The reason is that, in this study, the droop value is aggregated, so it does not depict the requirement for every single generator. Furthermore, despite the requirement, as generator headroom decreases, response capability also worsens. This behaviour has been observed in actual events in ERCOT in the past.

It has to be mentioned that $E_p$ can be also calculated directly based on the steady-state values (i.e. at $20 \text{ s after } t_{\text{dist}}$) of frequency deviation and power change. This approach has been followed for each event and generation.
type separately and the results that have been obtained are very similar to the ones presented in Tables III-V. However, it would be impossible to use this approach to find a single value of $E_p$ for all events. This is possible with the proposed methodology, since the optimization process can be applied to all events simultaneously.

It has to be noted that the differences in obtained parameters of the SCGT, CCGT, and ST from the simultaneous optimization of the ERCOT system models are small (Table VI). This implies the possibility to actually simplify even further with only one data set representing all these three types for the examined events. It should be mentioned though that the more the optimization gets simplified, the less accurate the frequency response assessment becomes.

6. Conclusion

The results of this study - and specifically of the separate optimization - showed that the governor response of the examined generation types can be accurately represented with the proposed open-loop simplified models. Furthermore, the paper proposed a methodology that can be employed in order to identify the unknown parameters. The same methodology can be successfully used for any generation type in any power system. However, the paper also showed that certain typical characteristics of the generation types cannot always be identified in the measured governor response. Therefore, every set of measurements from any generation type and power system should be treated separately. Such an example is the dependency of the power output of the SCGT and CCGT on frequency, which is not visible in the measurements that were available for this study.

The results also showed that simplified dynamic models can be employed instead of detailed ones, to save valuable time and resources, without compromising substantial accuracy. For example, simplified models, such as the ones presented in this study, can carry out many real time simulations to predict frequency, for given system conditions and several contingency scenarios. Furthermore, the importance of having accurate estimate of inertia for frequency response assessment was indicated in the closed-loop simulations. Since inertia is a parameter in the closed-loop model, if the value of the model parameter does not represent the actual inertia of the system, the predicted frequency signal can deviate significantly from the actual one.

This paper creates the path towards the development of generic models with one common set of parameters, that are able to represent the system under various conditions (i.e. different disturbance, different participation in the generation mix, different loading) based on some available metrics (e.g. capacity and available headroom). A common set of parameters was retrieved for both sets of data (ERCOT and Svk) by employing simultaneous optimization. However, more event data are required to achieve higher fidelity regarding the accuracy of the common parameter set.

7. Lessons learned – Future actions

A lot of challenges have been encountered during this study. First, the measurements were not synchronized. This led to a manual alignment, which might be affecting the accuracy of the results. Moreover, the temporal sampling resolution was quite coarse, since the measurements have been retrieved from the SCADA system. This resulted in valuable information not being observable in between the samples. Furthermore, only one frequency signal has been available for ERCOT and measurements from only 15 generators have been available for Svk. Higher observability is needed, especially for Svk, where significant frequency variations can be observed between distant generators. Finally, all 15 measurements for Svk come from HTs that are of the same type. However, there are different types of HTs in NPS. Hence, more measurements should be available to achieve higher fidelity concerning the accuracy of the HT parameters and the appropriate representation of all HT types at a system level.

The results would be much more accurate if PMU measurements were available from all generators of the system. In this way, plant performance monitoring would be improved and system awareness would vastly increase. SOs are aware of these challenges and solutions and have started taking actions. An example of such an action is that ERCOT requires new generators to be equipped with a PMU. Similar actions are also planned to be taken from Svk, which include the deployment of additional PMUs in the grid to increase the observability.
8. Acknowledgement

This work was funded through SweGRIDs, by the Swedish Energy Agency and Svenska kraftnät. The authors would also like to thank Sidharth Rajagopalan from ERCOT for his feedback.

It has to be noted that a significant part of this work is included in [29].

9. References


