3rd DSA Stakeholder Workshop
Brussels | 15 May 2019

Knud Johansen

15 May 2019

3rd DSA Stakeholder Workshop
Part 1: Welcome, introduction & follow up
10:00-11:30

Knud Johansen

15 May 2019

Lets present ourselves!

(shortly address expectations towards this WS)

TOP 1. Welcome and Introduction
Agenda

1. **Welcome, introduction and follow up (10:00-11:30)**
2. Coffee & tea break (11:30-11:45)
3. **Principles for DSA coordination in RG CE (11:15-11:45)**
4. Lunch (12:15-13:30)
5. **Principles for DSA coordination in RG Nordic (13:30-14:15)**
6. **Principles for DSA coordination in RG GB/IE/NI (14:15-14:45)**
7. Coffee & tea break (14:45-15:00)
8. **Q&A on DSA in general (15:00-15:45)**
9. **Conclusions and wrap up (15:45-16:00)**

TOP 1. Welcome and Introduction
WS Expectations

- Reference to the feedback received during the 1st and 2nd DSA Stakeholder Workshop (23 May and 18 Dec 2018)
- Overview on the activities within ENTSO-E on implementation requirements in respect to SO GL
  - art. 38 Dynamic stability monitoring and assessment (DSA)
  - art. 39 Dynamic stability management (MI - minimum inertia)
- Brief wrap-up of current practices on DSA in different synchronous areas and principles behind the applied tools and calculations / scenarios
- Exchange of views
- Gather feedback and expectations

- ENTSO-E expect that:
  - Stakeholders will obtain a deeper understanding of the DSA calculation principles and understanding of the impact / requirements on products and services.
  - ACER and the NRAs will obtain a deeper understanding of the DSA calculation principles and an understanding of how the regulators can support our efforts to maintain a stable grid in a future decarbonised scenario.

TOP 1. Welcome and Introduction
Quick reminder | Extracts from SO GL

- Articles concerned: 38, 39 in whole; 41, 45, 48, 57 partially (data exchange)
- Article 38: Dynamic Stability monitoring and assessment
  - Imposes obligations on individual/synchronous area TSOs on monitoring and exchanging data on DS (38.1) as well as on performance and coordination of DS assessment (38.2).
  - Determines criteria (38.3) and sets the rules for deciding on the methods (38.6) in DS assessment.
  - Dynamic stability includes - frequency stability, angle stability and small signal stability aspects
- Article 39: Dynamic Stability management
  - Imposes obligations to develop remedial actions if violations appear (39.1),
  - Imposes that fault clearing times are to shorter than critical time calculated within dynamic stability assessment (39.2)
  - Obligates TSO to conduct common studies for identification of establishing minimum inertia and (if the need demonstrated) imposes obligation on all TSOs from the concerned synchronous area (39.3.b) to develop methodology for the definition of minimum inertia required to maintain operational security and to prevent violation of stability limits.

TOP 1. Welcome and Introduction
Activities within ENTSO-E on SO GL art. 38 & 39

ENTSO-E TSO Workshops

- 08-09/11/17 1st WS dialog on current practices - DSA and MI
- 24/04/18 2nd WS aimed at first assessment and solutions in each SA
- 20/09/18 3rd WS aimed at discussion and 1st drafting of the solutions
- 9/04/19 4th WS on DSA monitoring and assessment

Actions taken | in-progress

- For MI - art. 39(3)(a)
  - All ENTSO-E Regional Groups addressed to timely deliver outcome of their studies (or updates), projects (RG CE and RG Nordic) or taking formal steps to confirm fulfilment of the requirements for the NRAs.
  - Report on progress is planned to be available in summer/autumn 2019.
- For DSA – art. 38
  - Ongoing activities
  - Next steps would be also influenced by the outcomes of this WS

TOP 1. Welcome and Introduction
Outcome from the 1st DSA WS with stakeholders – 23.05.2018

1. Participants acknowledged the need for monitoring the system inertia in all synchronous areas for normal and alert operation.
2. Stakeholders suggestion to extend the DSA coordination on agreeing among TSOs on the assumptions on the system split scenarios, including stakeholder's participation.
3. Stakeholders expectation on exchanging information on DSA assessment and management. Workshop concept seems to be an efficient solution.
4. Expectations form stakeholder on establishing a set of clear definitions/requirements on the algorithms/assumptions related to frequency stability aspects (synthetic inertia, fast frequency response functions) in order to enable industry/vendors to provide services.
5. The participants agreed that quality of models used for calculations is a key element for obtaining proper quality of results.
6. Suggestion from stakeholder for the TSOs to take the lead on the RoCoF studies / requirements.
7. Distinction between „network design" and "system design" were proposed as essential in the system stability discussions. The terms could be defined as follows:
   - "Network design" shall define the dimensioning of the transmission (and distribution) grid infrastructure. One relevant criterion for network design is robustness/resilience against normal and a number of exceptional contingencies (e.g. common mode failures).
   - "System design" shall define the robustness/resilience of the transmission (and distribution) system against more severe contingencies, which are beyond network design, e.g. exceptional contingencies without a common cause or out-of-range contingencies like system splits. These incidents shall be mitigated by system defense plans, to which all system users shall contribute through their system-supportive behaviour, e.g. by contributing to system inertia.
8. ACER requested a pan-European harmonization on scenario assumption and boundary condition for the DSA studies. Eventually a set of reference scenarios as used by EirGrid for generator testing.
9. Special Protection Schemes is considered in the scenarios simulated were presented at the workshop.
10. Investigation of a catalogue of "normative incidents" needs to be reviewed and whether we can prepare a of set principles for reference scenarios will be discussed on the ENTSO-E level. A more detailed look on the definitions on what is normal and what is abnormal must be included in the review.

→ Principles behind the DSA calculation scenarios and algorithms applied

TOP 1. Welcome and Introduction
Outcome from the 2nd DSA WS with stakeholders – 18.12.2018

Questions raised by stakeholders

→ **see separate doc file**

Coffee & tea break

11:30 – 11:45

Backup slides

SO GL art. 38 Dynamic stability monitoring and assessment

1. *Each TSO shall monitor the dynamic stability of the transmission system by studies conducted offline in accordance with paragraph 6. Each TSO shall exchange the relevant data for monitoring the dynamic stability of the transmission system with the other TSOs of its synchronous area.*
2. *Each TSO shall perform a dynamic stability assessment at least once a year to identify the stability limits and possible stability problems in its transmission system. All TSOs of each synchronous area shall coordinate the dynamic stability assessments, which shall cover all or parts of the synchronous area.*
3. *When performing coordinated dynamic stability assessments, concerned TSOs shall determine:*
   a) *the scope of the coordinated dynamic stability assessment, at least in terms of a common grid model;*
   b) *the set of data to be exchanged between concerned TSOs in order to perform the coordinated dynamic stability assessment;*
   c) *a list of commonly agreed scenarios concerning the coordinated dynamic stability assessment; and*
   d) *a list of commonly agreed contingencies or disturbances whose impact shall be assessed through the coordinated dynamic stability assessment.*
4. *In case of stability problems due to poorly damped inter-area oscillations affecting several TSOs within a synchronous area, each TSO shall participate in a coordinated dynamic stability assessment at the synchronous area level as soon as practicable and provide the data necessary for that assessment. Such assessment shall be initiated and conducted by the concerned TSOs or by ENTSO for Electricity.*
5. *When a TSO identifies a potential influence on voltage, rotor angle or frequency stability in relation with other interconnected transmission systems, the TSOs concerned shall coordinate the methods used in the dynamic stability assessment, providing the necessary data, planning of joint remedial actions aiming at improving the stability, including the cooperation procedures between the TSOs.*
6. *In deciding the methods used in the dynamic stability assessment, each TSO shall apply the following rules:*
   a) *if, with respect to the contingency list, steady-state limits are reached before stability limits, the TSO shall base the dynamic stability assessment only on the offline stability studies carried out in the longer term operational planning phase;*
   b) *if, under planned outage conditions, with respect to the contingency list, steady-state limits and stability limits are close to each other or stability limits are reached before steady-state limits, the TSO shall perform a dynamic stability assessment in the day-ahead operational planning phase while those conditions remain. The TSO shall plan remedial actions to be used in real-time operation if necessary; and*
   c) *if the transmission system is in the N-situation with respect to the contingency list and stability limits are reached before steady-state limits, the TSO shall perform a dynamic stability assessment in all phases of operational planning and re-assess the stability limits as soon as possible after a significant change in the N-situation is detected.*

SO GL art. 39 Dynamic stability management

1. *Where the dynamic stability assessment indicates that there is a violation of stability limits, the TSOs in whose control area the violation has appeared shall design, prepare and activate remedial actions to keep the transmission system stable. Those remedial actions may involve SGUs.*
2. *Each TSO shall ensure that the fault clearing times for faults that may lead to wide area state transmission system instability are shorter than the critical fault clearing time calculated by the TSO in its dynamic stability assessment carried out in accordance with Article 38.*
3. *In relation to the requirements on minimum inertia which are relevant for frequency stability at the synchronous area level:*
   a. *all TSOs of that synchronous area shall conduct, not later than 2 years after entry into force of this Regulation, a common study per synchronous area to identify whether the minimum required inertia needs to be established, taking into account the costs and benefits as well as potential alternatives. All TSOs shall notify their studies to their regulatory authorities. All TSOs shall conduct a periodic review and shall update those studies every 2 years;*
   b. *where the studies referred to in point (a) demonstrate the need to define minimum required inertia, all TSOs from the concerned synchronous area shall jointly develop a methodology for the definition of minimum inertia required to maintain operational security and to prevent violation of stability limits. That methodology shall respect the principles of efficiency and proportionality, be developed within 6 months after the completion of the studies referred to in point (a) and shall be updated within 6 months after the studies are updated and become available; and*
   c. *each TSO shall deploy in real-time operation the minimum inertia in its own control area, according to the methodology defined and the results obtained in accordance with paragraph (b).*

Outstanding questions from 2nd DSA workshop

ENTSO-E

3rd DSA workshop, Brussels, 15 May 2019

Principles for DSA reference scenarios in RG CE 1/2

Questions/Remarks	Draft replies
Future RoCoF will be 2 Hz/second, and it says on the slides that it is approved by stakeholders: which stakeholders have approved it? Have the generators accepted this? (GE has stated that 1 Hz/second is the upper limit for many installations)	Measurements have shown that up to 1 Hz/s, the system might be "saved", any higher RoCoF is a risk for current technology (generators, LFDD equipment)
Is it possible to get a better explanation of the table describing the scenarios ?	The simulation scenarios are evaluated checking in parametric way the system behaviour with different imbalance, inertia and acceptable RoCoF
How was the information collected for defining RoCoF? ROCOF shall be always associated to time window. Which time window is associated with the ROCOF of 2 Hz/s. What is the meaning of system resilience (the system will become unstable, frequency will crush ?	See https://docstore.entsoe.eu/Documents/SOC%20documents/Regional_Groups_Continental_Europe/2018/TF_Freq_Meas_v7.pdf
6% droop -> valid for any size of generating unit? Any area within CE ?	The recommended value is 5 % but different values can be chosen depending also from local needs/technology
Response time of 1s seems to be unrealistic for big power plant, based on the capacity of fast valving. Feedback had been provided that this is not feasible for many technologies, unless opening their main CB. Some technologies have also minimum load. How this has been taken in consideration? Finally, this 1s is not, as far as I know, taken in consideration in the implementation at national level	1 sec is a realistic value for conventional power plant and can be obtained depending by technology. The steam plants thanks to fast valving and HP valves can react in less than 1 sec. Also hydro power plants with water interceptor can be very fast. Other technologies can reach the requested performance in several ways.

Principles for DSA reference scenarios in RG CE 2/2

Questions/Remarks	Draft replies
Not sure I understand the concept of having no minimum inertia requirement and having a problem of high RoCoF. My takeaway is that a 1 Hz/s ROCOF is ok for the CE system and 2 Hz/s is not, then minimum inertia shall be specified to meet the 1 Hz/s RoCoF. Has this analysis been carried out?	The basic concept is the direct relationship between inertia and system RoCoF. The approach of the study was to create a parametric correlation that permits to follow this scheme: 1. Select the maximum RoCoF we want for our system 2. See on the graphs what is the maximum imbalance that we can accept with different mix of nonsynchronous generation
I'm wondering if CE as a conclusion can recommend a DSA for smaller synchronous area can be considered. For smaller area ("local"), DSA can be carried out with more detail and minimum inertia defined. That would prevent the creation of critical areas with a too low inertia. Maybe, considering too large synchronous area with too many contributors, can create problem in defining and calculating such minimum value. (if the minimum inertia value is recognized even as an indicator of criticality where remedy action shall be considered). Could you crosscheck if this approach could be viable?	The approach of SPD can be resumed as follows: for local TSO area the DSA can be implemented with accurate modelling of the system. About the whole ENTSO-E system, at moment the best approach in terms of correct level of conservativism and realistic behaviour is the one busbar approach. SPD is working to set up a nodal model but at the moment this model is not sufficient mature to drive studies.
Inertia is not the only problem, also small signal stability is an issue, this should be brought to study group	Correct, but the correlation between inertia and inter-area oscillation will have to be considered carefully as we always have in this case a combination of impact of inertia and controller settings as well as impedance between the oscillating areas.

Historical data / evolution of inertia for CE

- The “simple” approach that can be applied for smaller systems like Ireland or GB or even Nordic system to simply sum-up all synchronous generating units for different system loading cases is quite challenging for the CE power system.

- ENTSO-E/SPD has already tried and is somehow reporting the RoCoF after each forced unit outage higher 1000 MW within along the years in order to “see” the inertia impact.

- It should also be understood where the real risk within the CE power system is – namely during system split with respect to frequency stability etc., consequently we will have to focus on that much more as on a currently and for more that 10-20 years ahead simple overall inertia number for the CE power system.

Principles for DSA Scenarios in RG CE

3rd DSA Stakeholder Workshop

SG System Protection and Dynamics (SPD)

15.05.2019

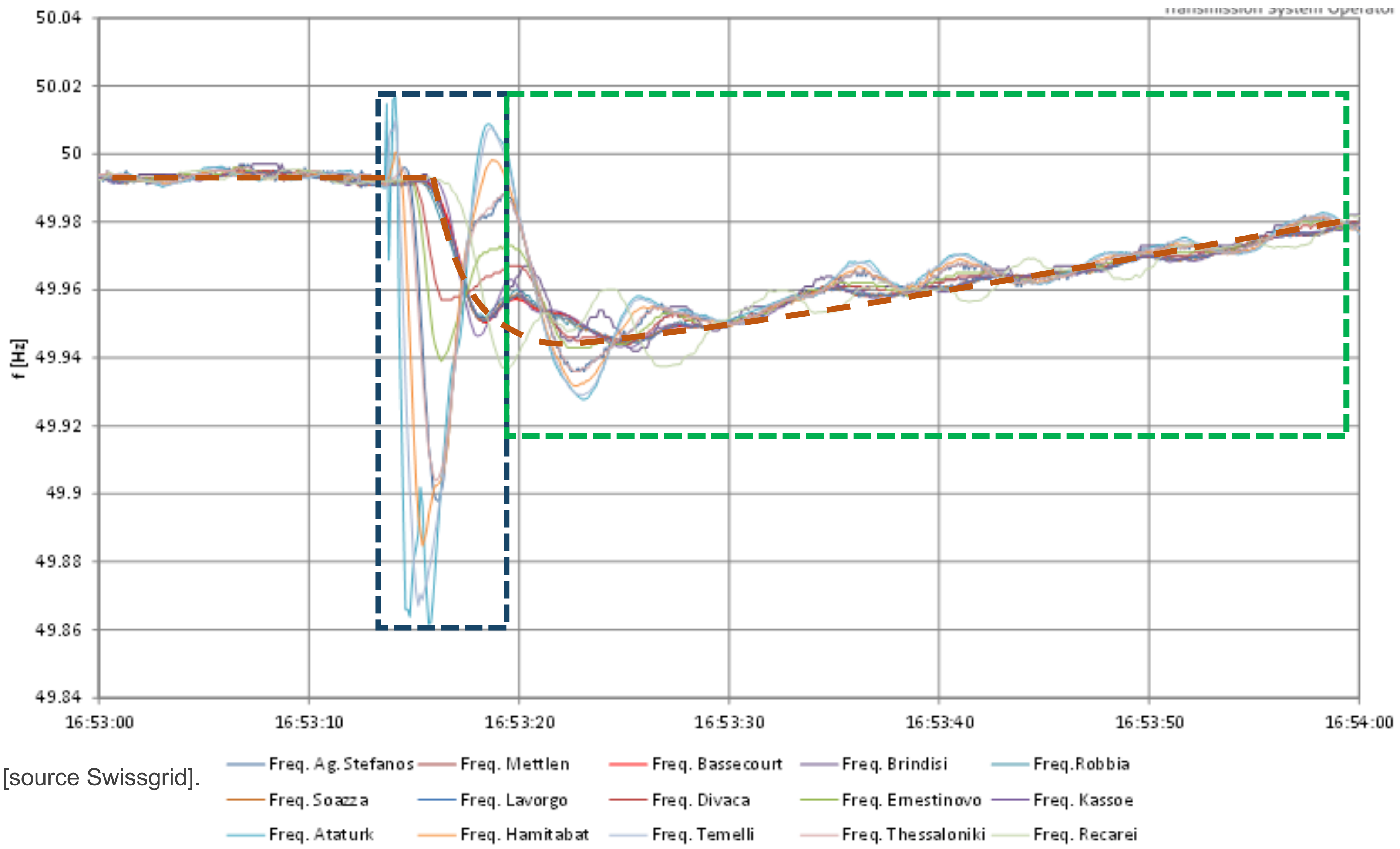
Hans Abildgaard Giorgio Giannuzzi Walter Sattinger

Follow up

Regional response on SO GL art 39(3)

RG CE

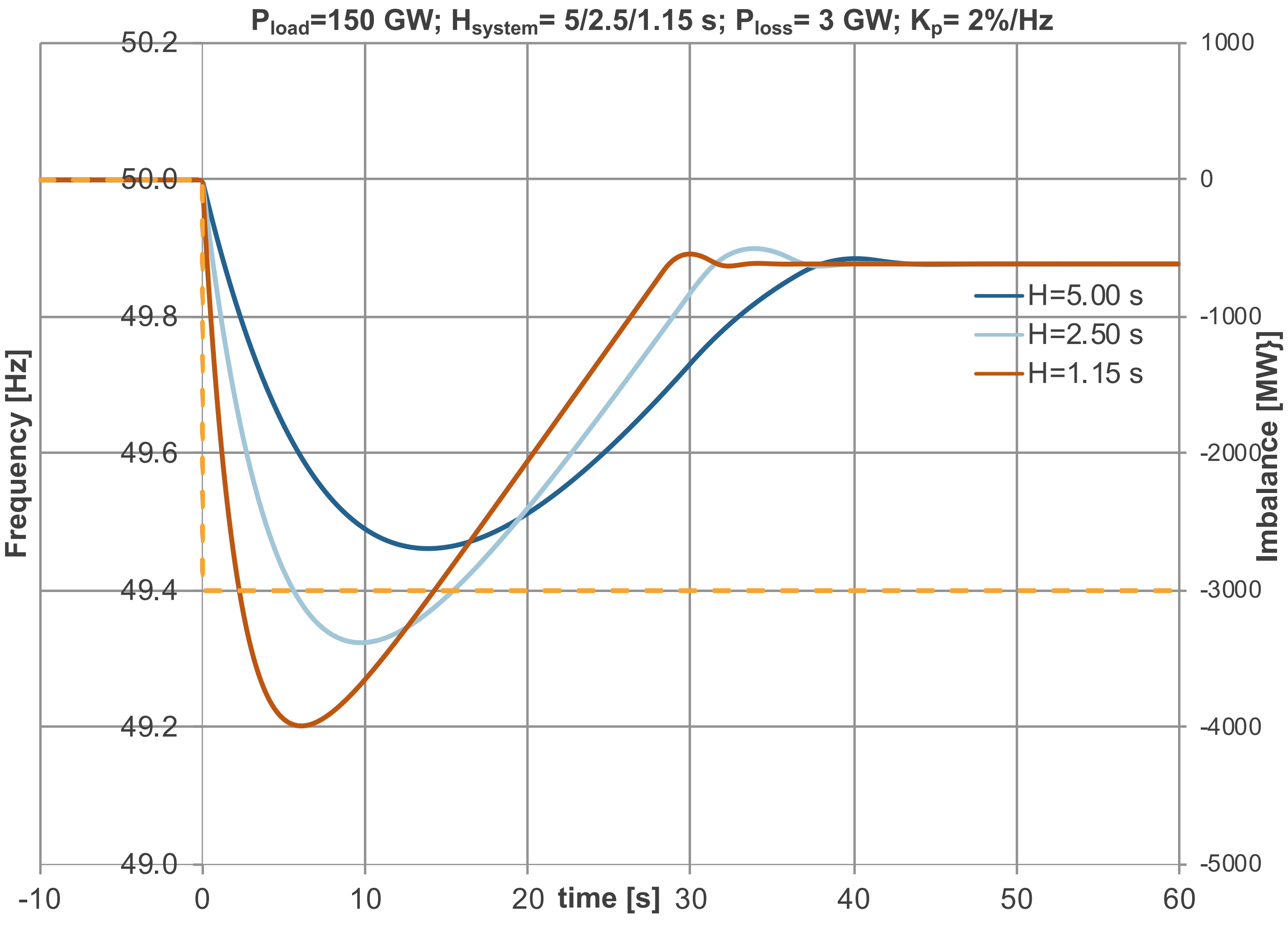
Example of recording of system frequency across the synchronous area after trip of power station in Turkey 01.01.2019



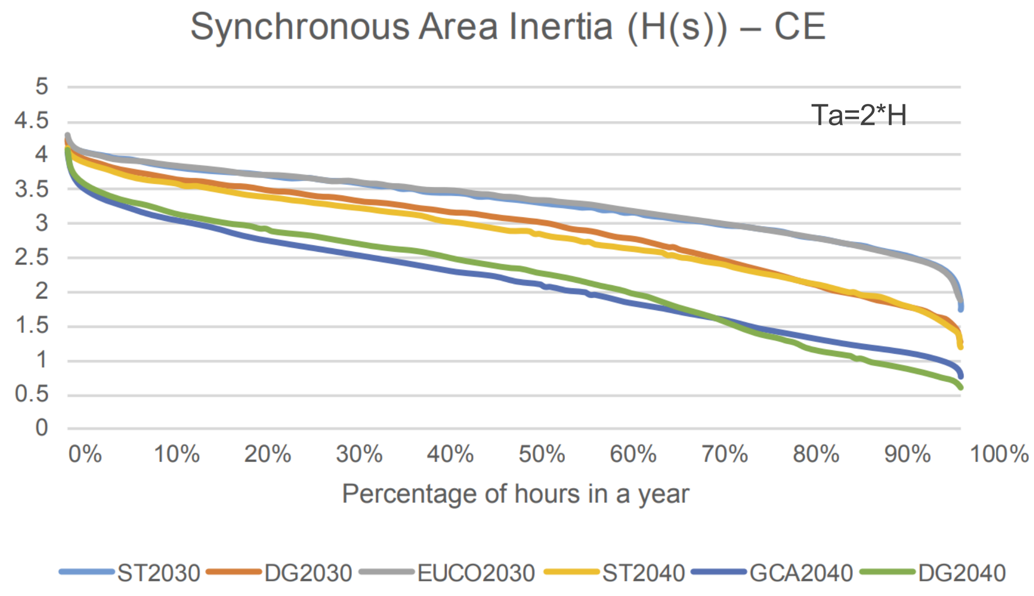
[source Swissgrid].

- Uniform frequency may take multiple seconds to establish
- Oscillation pattern depends on multiple factors
    - generation mix
    - grid impedance
    - location of the imbalance
    - demand and generator response.
- "Inertia" relates to the initial rate of change of frequency immediately after the system imbalance occurs

SOGL A39 CE inertia in low load case/normative incident



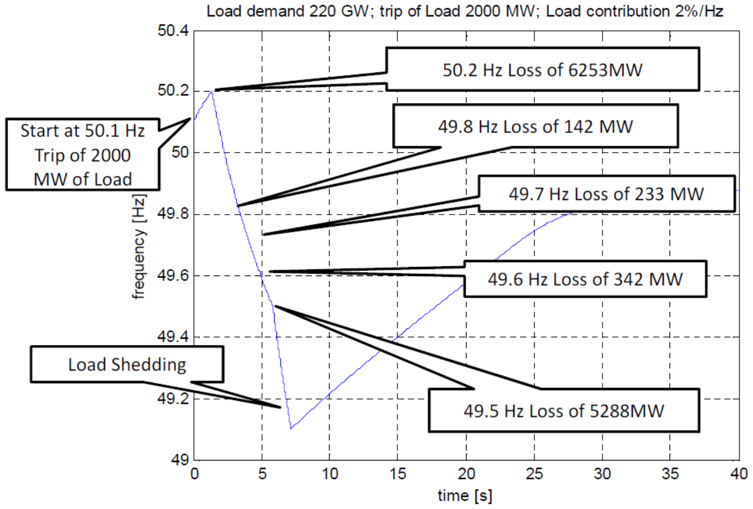
https://www.entsoe.eu/Documents/SOC%20documents/RGCE_SPD_frequency_stability_criteria_v10.pdf



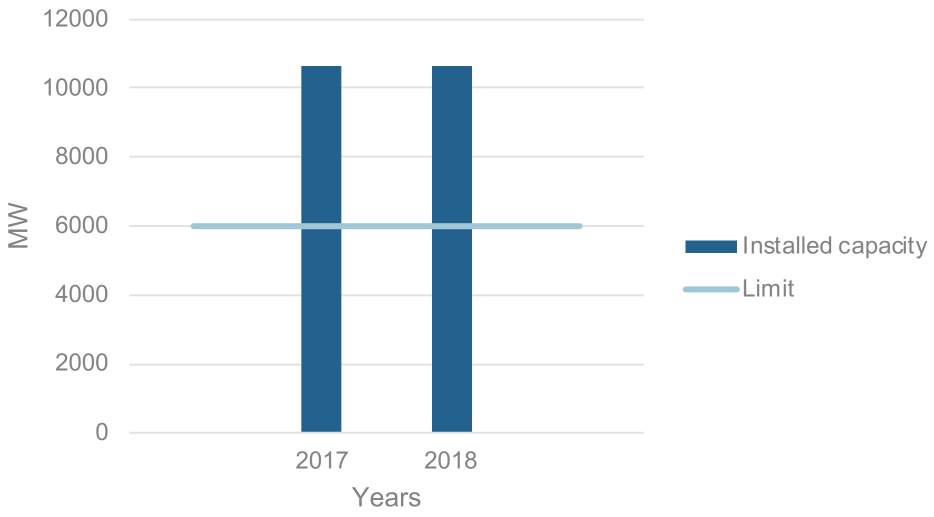
https://docstore.entsoe.eu/Documents/TYNDP documents/TYNDP2018/System_Need Report.pdf

Over frequency is critical for other reasons

- Loss of load leads to over frequency
- The normative incident for over frequency is smaller (easier to manage)
    - f< loss of generation 3 GW
    - f> loss of load 2 GW
- Non-compliant generation disconnecting at 50.2 Hz poses a serious threat to frequency stability
    - Cannot realistically be mitigated by enforcing a minimum inertia
- After retrofit or without significant contribution from non-compliant generation
    - It is generally easier to reduce rather than increase power generation

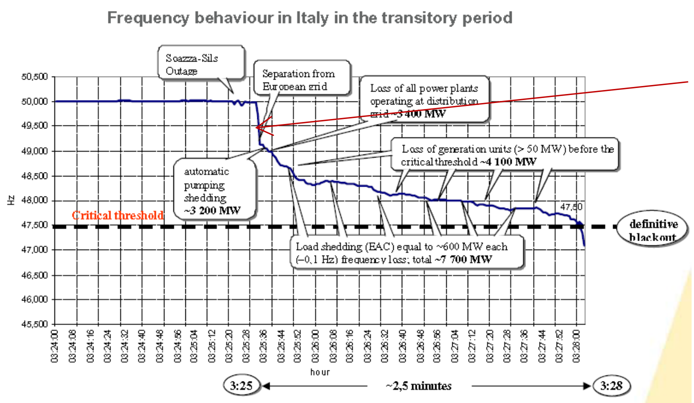


Evolution of capacity disconnecting within 50-50.2Hz



System recordings- RoCoF and imbalance

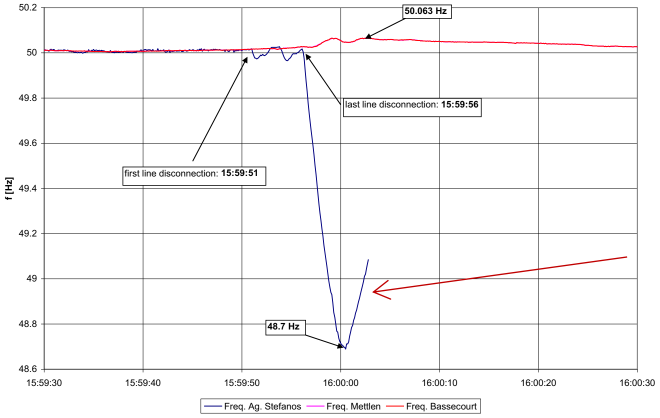
IT 28.09.2003 ☺



0.5 Hz/s
26% Imbalance Ratio

Source: UCTE /2/

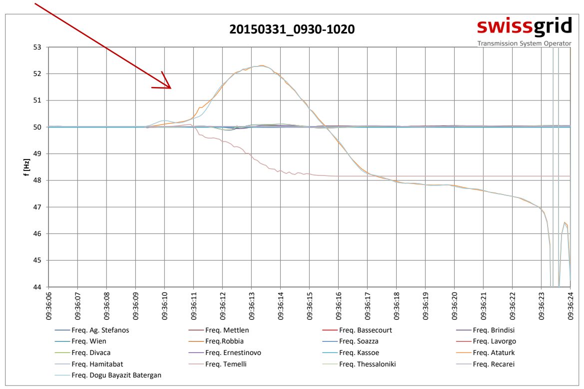
GR 24.07.2007 ☺



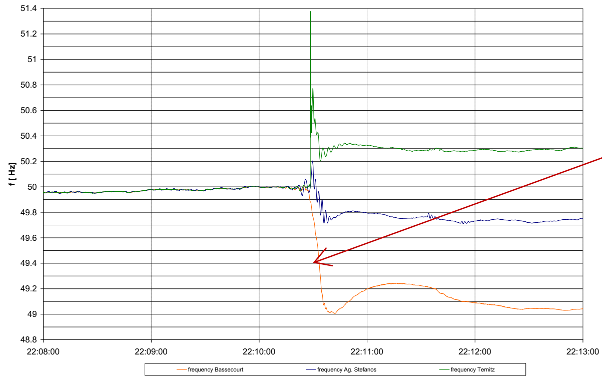
300 mHz/s
10% Imbalance Ratio

1 Hz/s ; 500 mHz/s
+42/-21% Imbalance Ratio

TR 31.03.2015 ☹

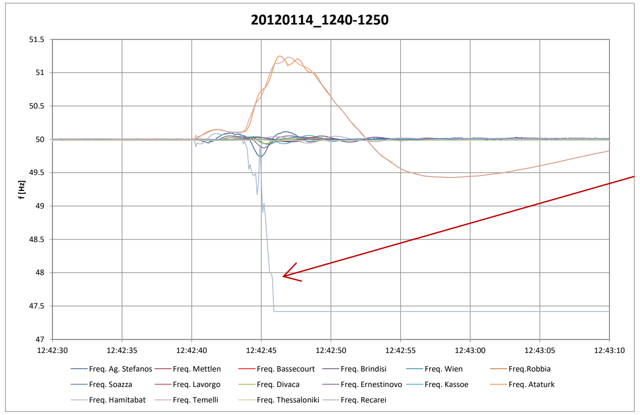


DE 04.11.2006 ☺



125 mHz/s
5% Imbalance Ratio

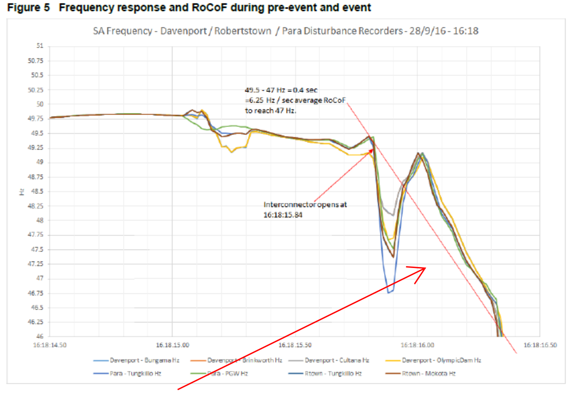
TR 14.01.2012 ☹



1 Hz/s
40% Imbalance Ratio

AU 28.09.2016 ☹

Figure 5 Frequency response and RoCoF during pre-event and event



6.25 Hz/s;
50% non-synchronous generation
18% Imbalance Ratio

Mitigation of low inertia issues

Multiple solutions

- Limited Frequency Sensitive Mode (LFSM)
- ”Synthetic” inertia
- Frequency support between synchronous areas via HVDC
- Load cross trip at loss of generation
- Synchronous condenser (with flywheels)
- Fast demand response (including batteries)
- Reduction of largest injection
- …

Article 39 Minimum inertia requirements

1st DSA Stakeholder Workshop

Analysis for Continental Europe

- In the CE system inertia challenge is only relevant in case of a system split which is covered by NC ER

Implementation proposal

- The required study to identify the need of a minimum inertia will be prepared by SG SPD.
- Existing SPD studies can be used to prove, that a minimum inertia is not required for ordinary and exceptional contingencies in CE.
- This study will also point out, that requirements on minimum inertia have to be discussed as part of the defense plan (NC Emergency and Restoration)

Article 39
All TSOs of a synchronous area shall conduct a common study to identify whether a minimum required inertia needs to be established, taking into account costs and benefits and potential alternatives.
If this study determines that a minimum inertia requirement is needed, the TSOs shall develop a methodology how to determine a minimum required inertia.

RG CE

Principles for DSA coordination in RG CE acc. to SO GL art 38(2)

Article 38 Dynamic stability monitoring and assessment

Analysis for Continental Europe

- SO GL addresses issues relevant for normal and alert state
- In the CE system frequency stability assessment is covered by the 3 GW FCR provision
- Beyond normal and alert state frequency stability is relevant for the defense plan which is addressed in NC ER
- DSA is required only for rotor-angle and voltage stability monitoring and assessment

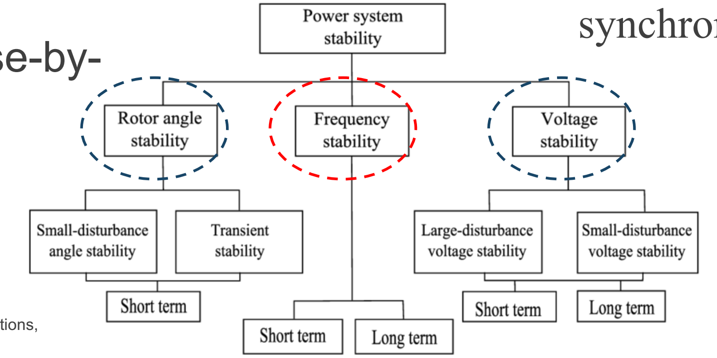
Implementation proposal

- Each TSO develops an individual DSA concept for his control area and involves neighboring TSOs if necessary
- DSA can be limited to transient rotor-angle stability and voltage stability
- Small-disturbance angle stability addressed by expert group for the synchronous area (SPD) on a case-by-case basis and for relevant TSOs
    - Accurate damping requires accurate load models

Article 38

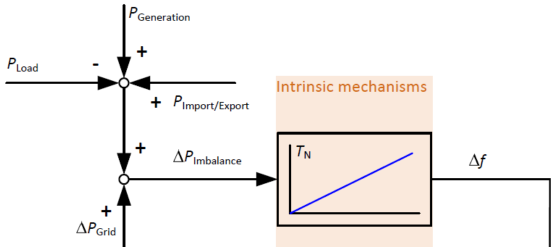
Each TSO is obliged to implement a Dynamic Stability Assessment (DSA) in his control zone and to perform it at least once a year

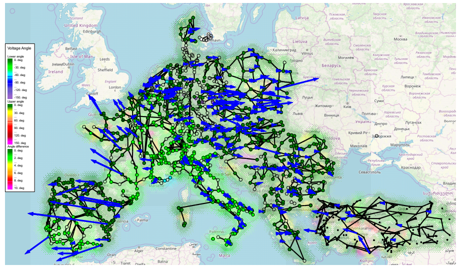
- Minimum as an offline application
- Dynamic stability includes rotor-angle stability, frequency stability and voltage stability
- All TSOs of a synchronous area shall coordinate DSA concerning models, scenarios and contingencies
- DSA shall cover all or parts of the synchronous area.



Definition and classification of power system stability
IEEE/CIGRE joint task force on stability terms and definitions,
IEEE Transactions on Power Systems, Aug. 2004

System inertia – simulation approach

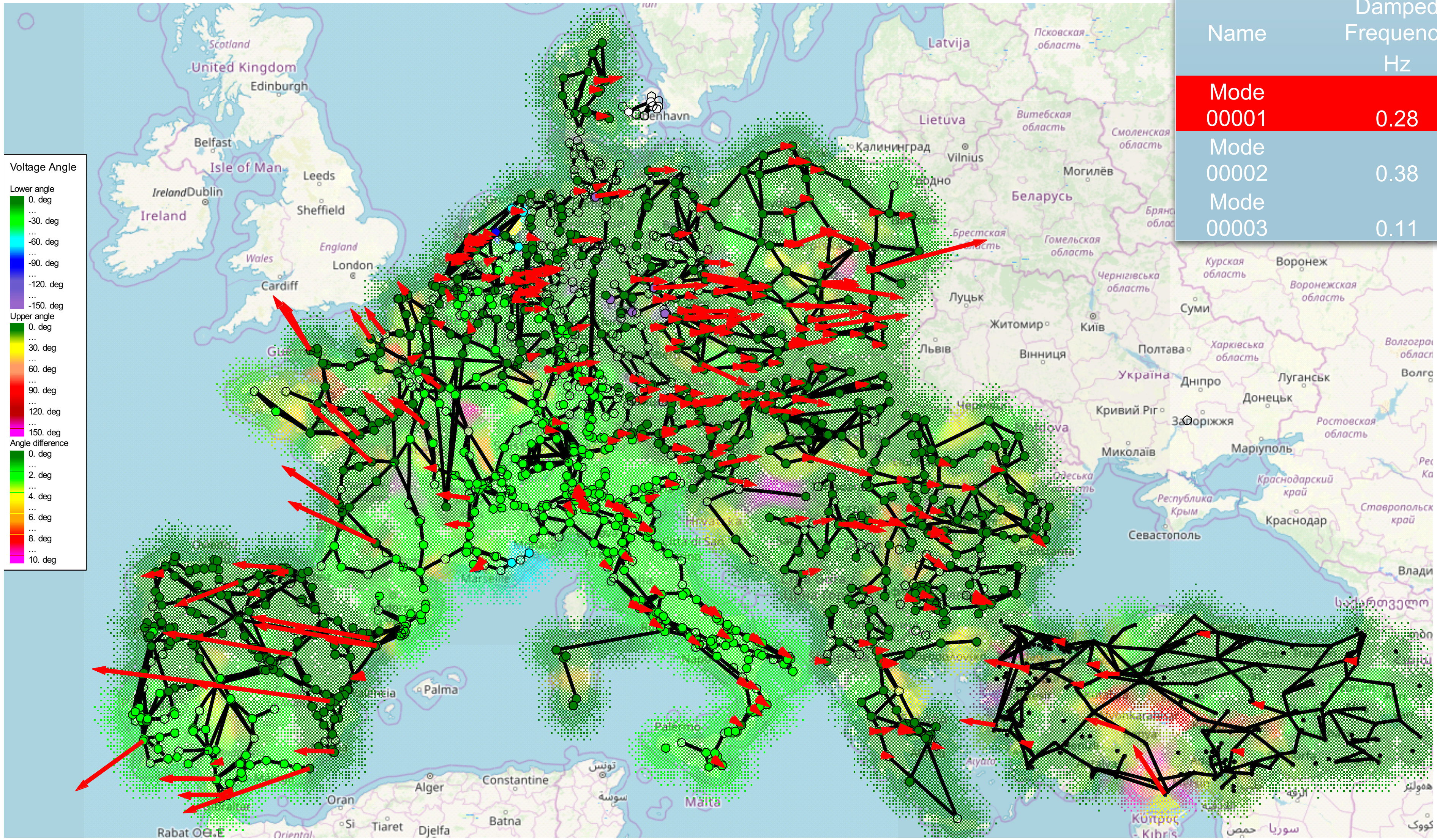




	Balance model (single busbar)	Nodal model
Objective	Reproduce system design	"Background model" for inter area oscillation modes, FCR response
Scenario	Multiple scenarios	Single scenario.
Flexibility	Easy execution of parameter sensitivity studies	Requires retuning of each scenario to reflect local conditions. This requires substantial efforts and only a few scenarios can be studies.
Models	Generic models based on normative response	Generic models. Work in progress to add more details on generating technology and HVDC
Interoperability	Simulation tool available at all TSOs	Work to ensure interoperability between TSO simulation tools is ongoing

Nodal dynamic model under development

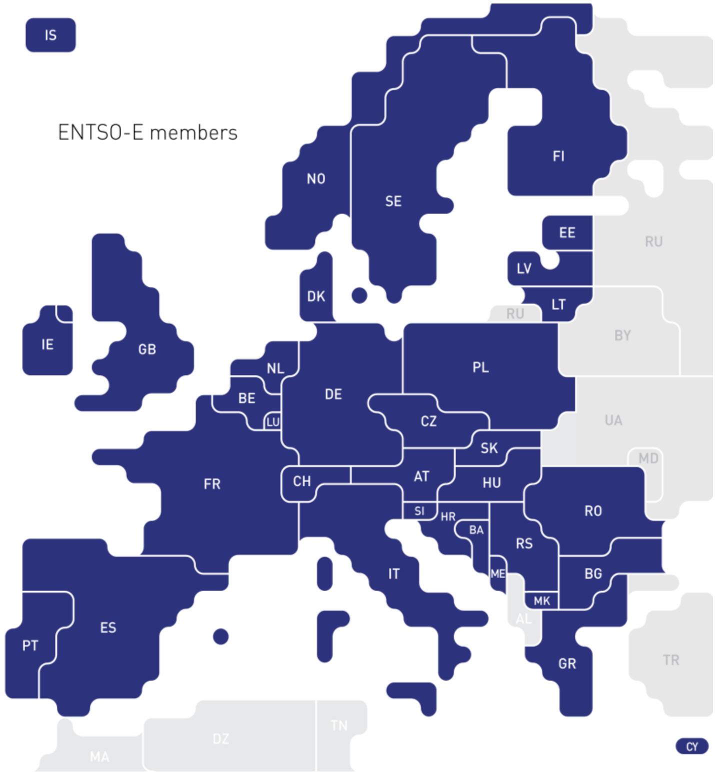
Example



Name	Damped Frequency Hz	Period s	Damping 1/s	Damping Ratio pu
Mode 00001	0.28	3.56	0.42	0.23
Mode 00002	0.38	2.65	0.19	0.08
Mode 00003	0.11	9.42	0.26	0.36

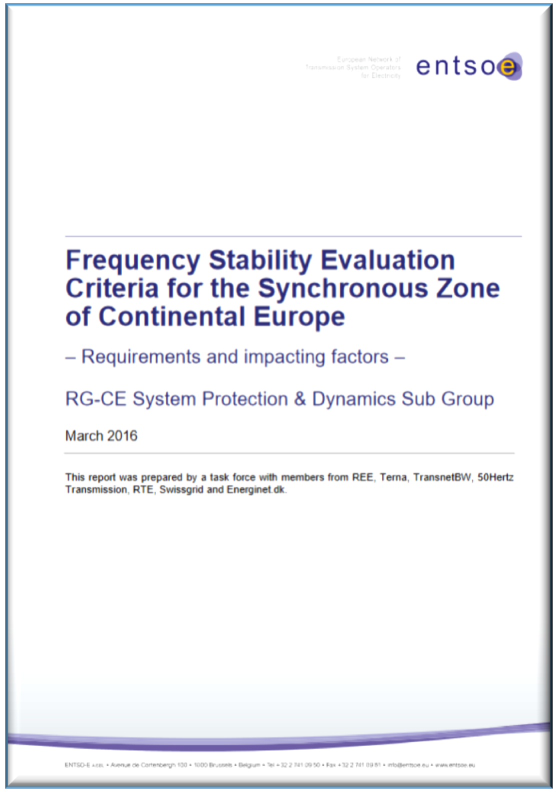
Continental Europe – approach for DSA

- Each TSO develops an individual DSA concept for his control area and involves neighbouring TSOs if necessary
- To avoid false conclusions system design settings are based on a single-bus model
  - Allows analysing multiple scenarios
- Work in progress to improve the nodal dynamic nodal model with more details on generating technology
  - Based on generic information
  - Developed for a single scenario
  - A properly tuned nodal model enables analysis of specific incidents but requires retuning for each scenario
  - On-going work to ensure interoperability between simulation tools



Continental Europe
32 TSOs in 28 countries

References related to Network Code Implementation from subgroup System Protection and Dynamics (SPD)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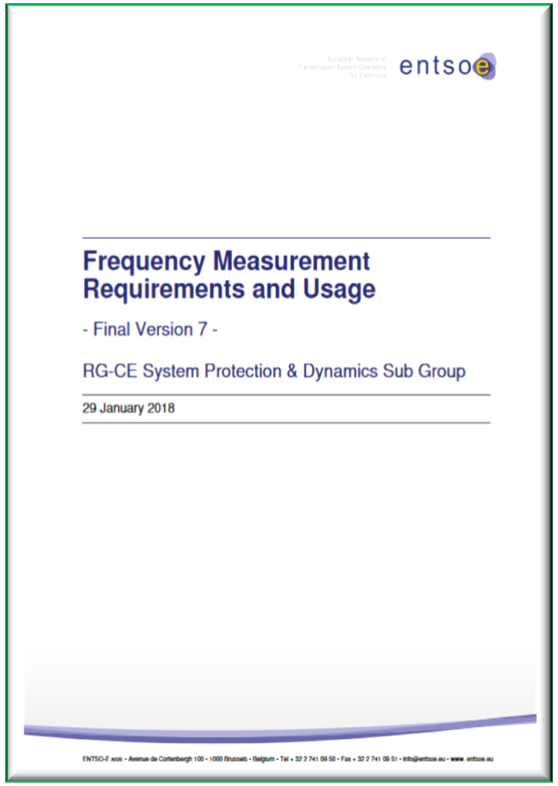
Frequency Stability Evaluation Criteria for the Synchronous Zone of Continental Europe

– Requirements and impacting factors –

RG-CE System Protection & Dynamics Sub Group

March 2016

This report was prepared by a task force with members from REE, Terna, TransnetBW, 50Hertz Transmission, RTE, Swissgrid and Energinet.dk.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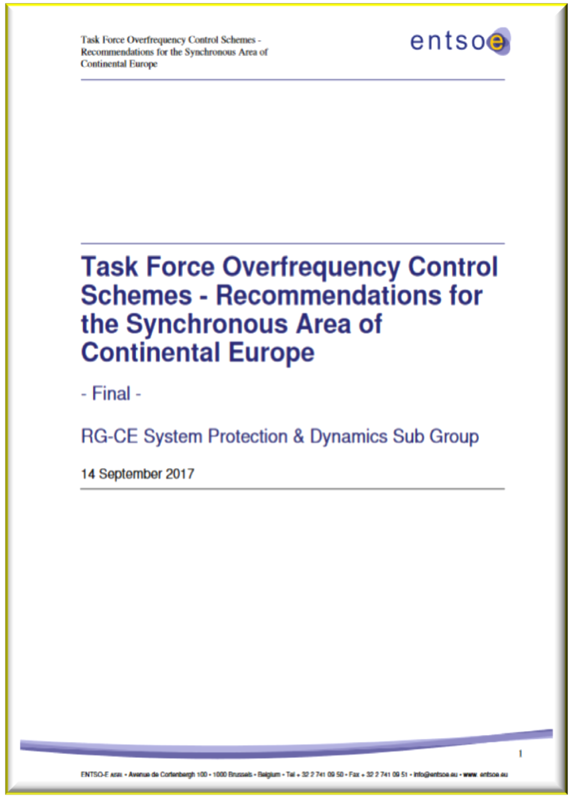
Frequency Measurement Requirements and Usage

- Final Version 7 -

RG-CE System Protection & Dynamics Sub Group

29 January 2018


Task Force Overfrequency Control Schemes - Recommendations for the Synchronous Area of Continental Europe

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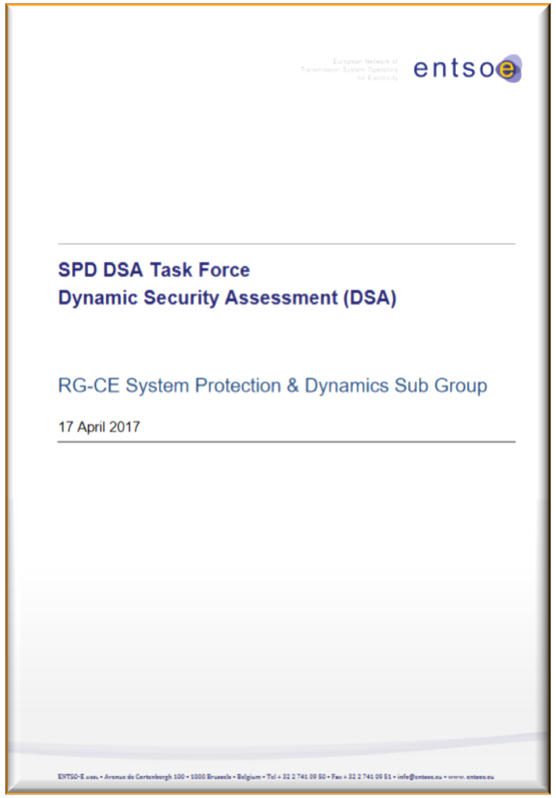
Task Force Overfrequency Control Schemes - Recommendations for the Synchronous Area of Continental Europe

- Final -

RG-CE System Protection & Dynamics Sub Group

14 September 2017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SPD DSA Task Force
Dynamic Security Assessment (DSA)

RG-CE System Protection & Dynamics Sub Group

17 April 2017

Subgroup SPD supported NC implementation in Continental Europe with studies related to

1. Effect of Inertia on System Stability
2. Frequency Measurement Requirements
3. Overfrequency Control Schemes
4. DSA Applications

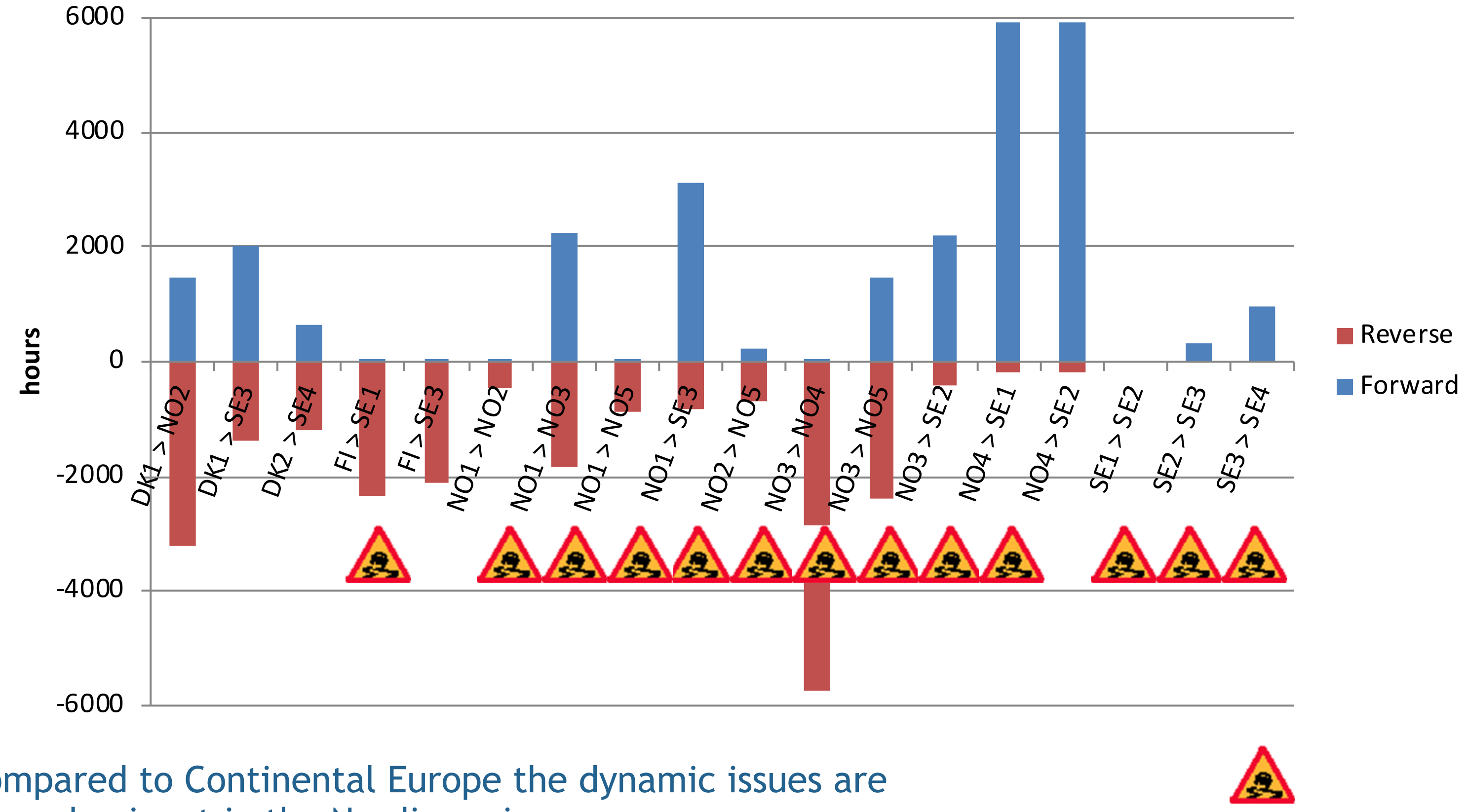
DSA issues for the Nordic region

DSA stakeholder workshop on SOGL A38-39

H. Kuisti

Brussels May 15 2018

Market limitations on Nordic internal borders



Compared to Continental Europe the dynamic issues are more dominant in the Nordic region

DSA and SO GL

Most relevant for Nordics is Art. 38.6:

(b) if, under planned outage conditions, with respect to the contingency list, **steady-state limits and stability limits are close to each other** or stability limits are reached before steady-state limits, the **TSO shall perform a dynamic stability assessment in the day-ahead operational planning phase** while those conditions remain. The TSO shall plan remedial actions to be used in real-time operation if necessary; and

(c) if the transmission system is in the N-situation with respect to the contingency list and **stability limits are reached before steady-state limits**, the **TSO shall perform a dynamic stability assessment in all phases of operational planning** and re-assess the stability limits as soon as possible after a significant change in the N-situation is detected.

DSA and SO GL

- DSA is already a part of transmission capacity calculation and operational planning
- A coordinated methodology will be gradually introduced and included Nordic System Operation Agreement
- Examples of present coordination activities:
  - Nordic load flow model updated regularly
  - Dynamic models will be included in CGM in the future
  - Coordination of EPC settings of HVDC-links

Performing DSA

Off-line studies already possible:

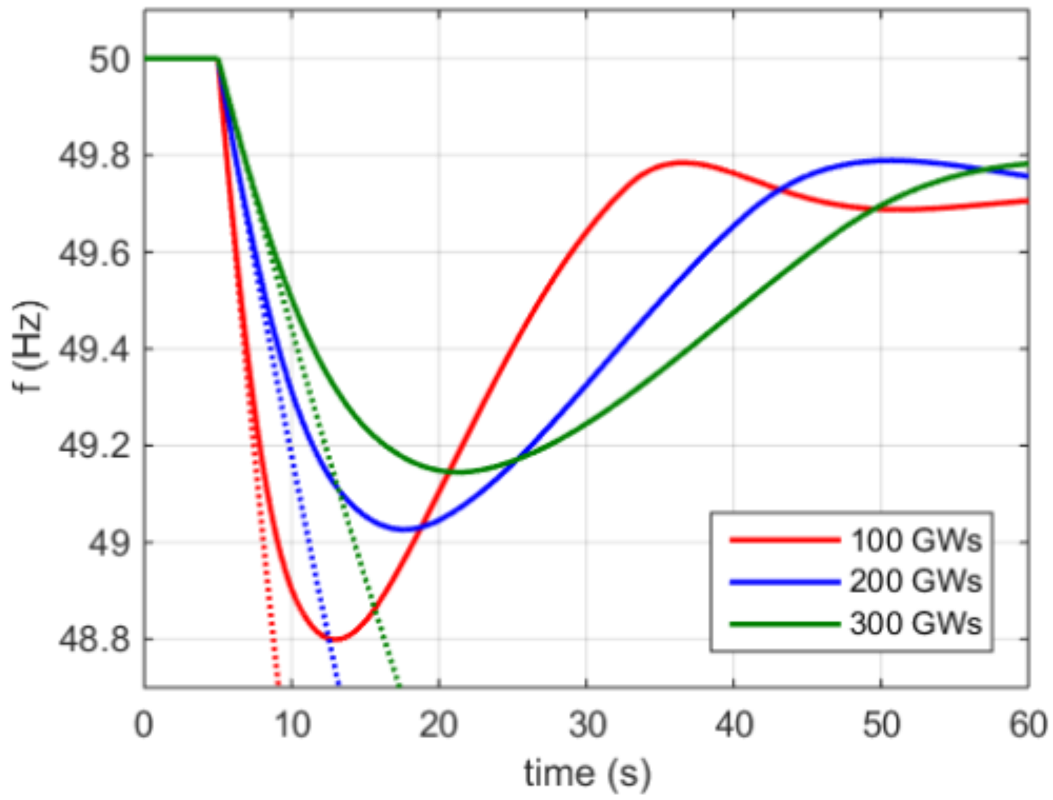
- **Nordic planning model (PSS/E)**
- **Svk and SN use also Aristo**

In future nearly real-time DSA becomes possible:

- **Common grid model will include dynamic models**
- **Many of dynamic models in Nordic planning model will need to be recreated in order to suit CGMES-standard**

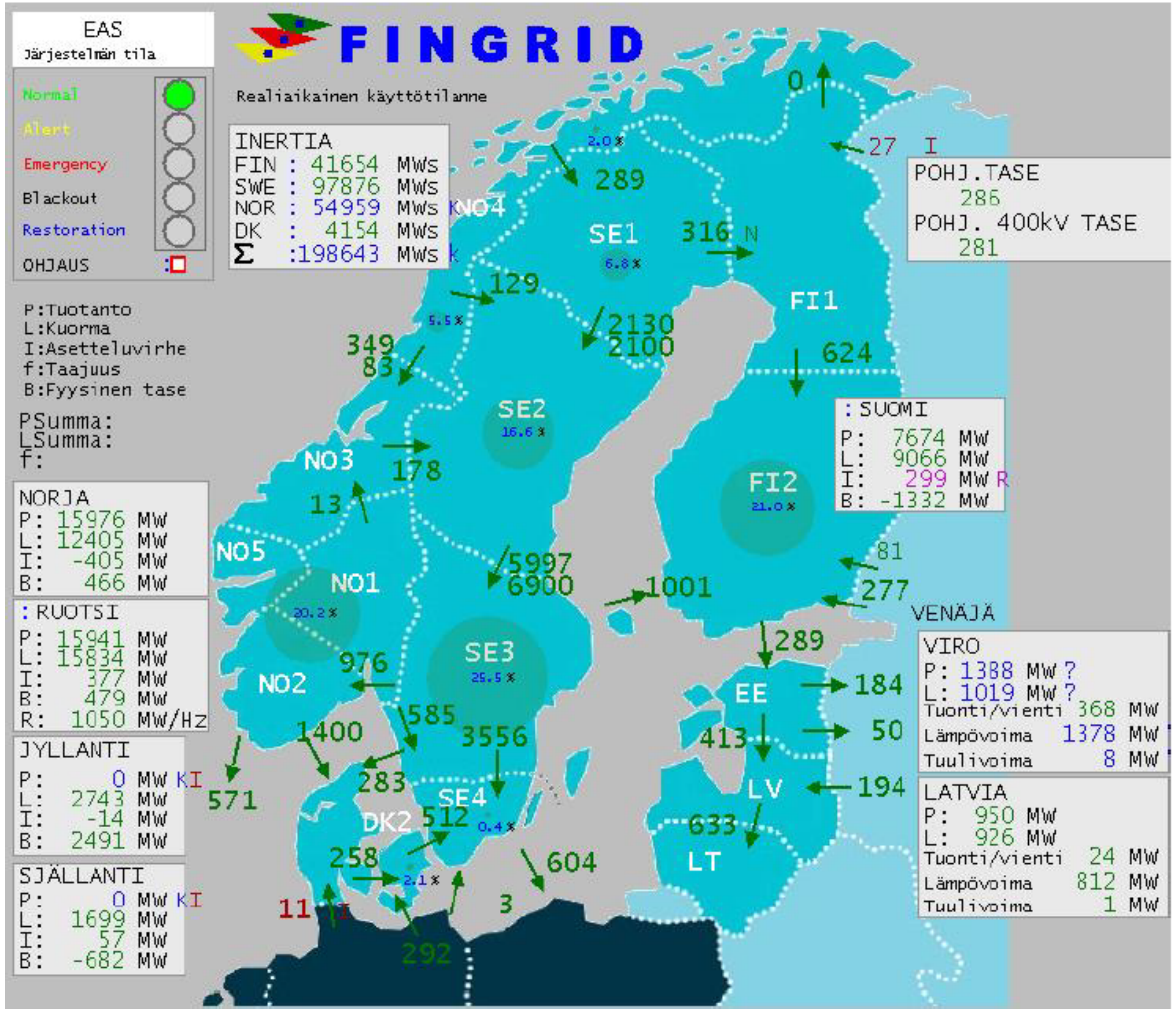
Inertia in the Nordic synchronous area

System reserves designed for loss of largest unit (1450MW: FCR-D 1250MW + load self regulation)



Inertia monitoring

- Tool developed to monitor the inertia real time level in the Nordic region
- Bottom-up approach
  - Based on breaker state and power measurements
- Visualized in each Nordic control room
- Further reading [Nordic report Future system inertia]()



Inertia variation

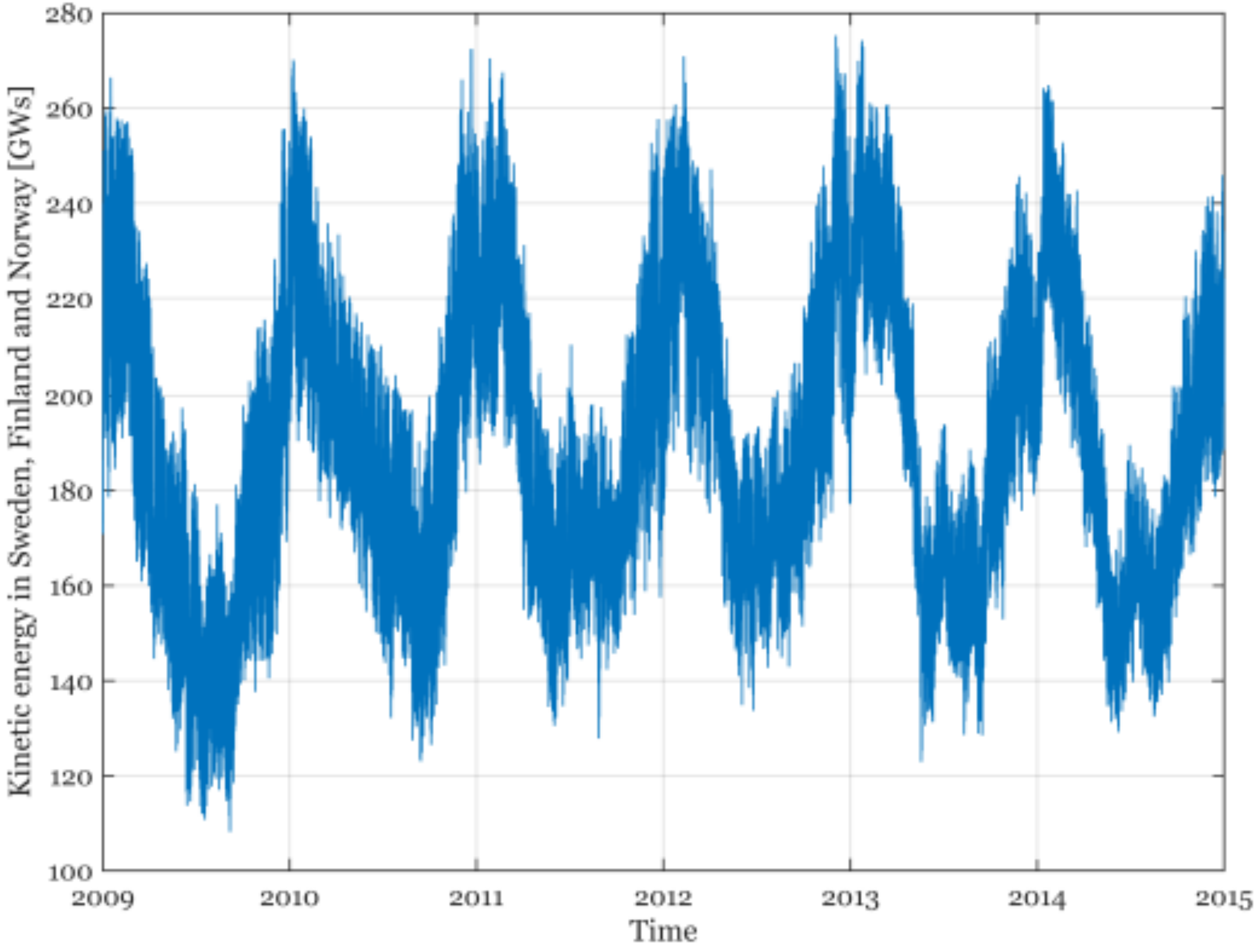
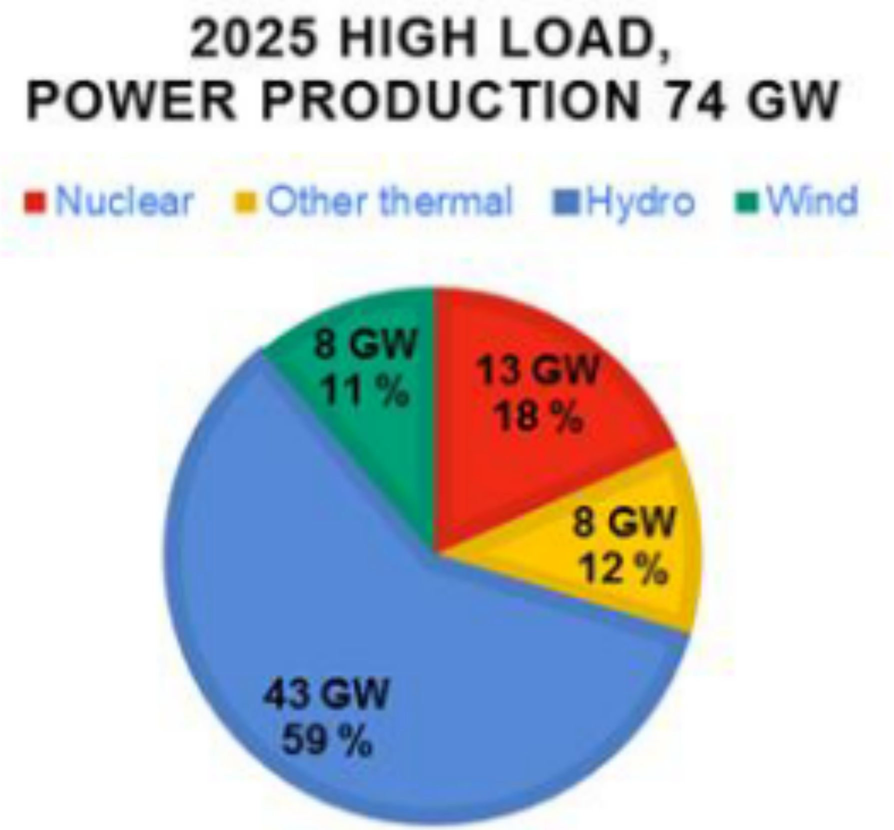
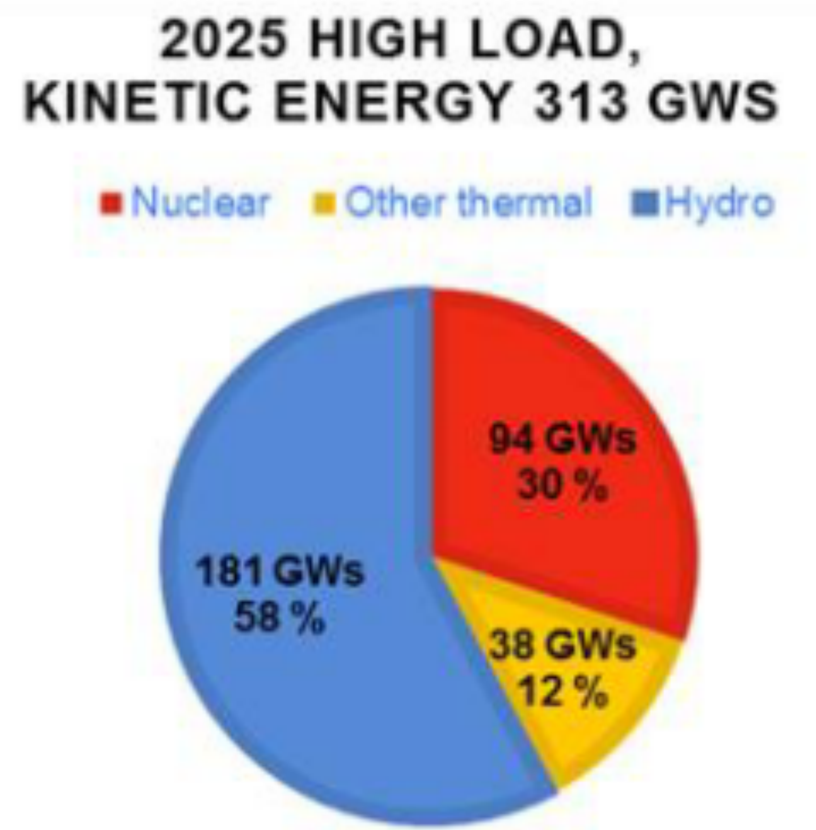


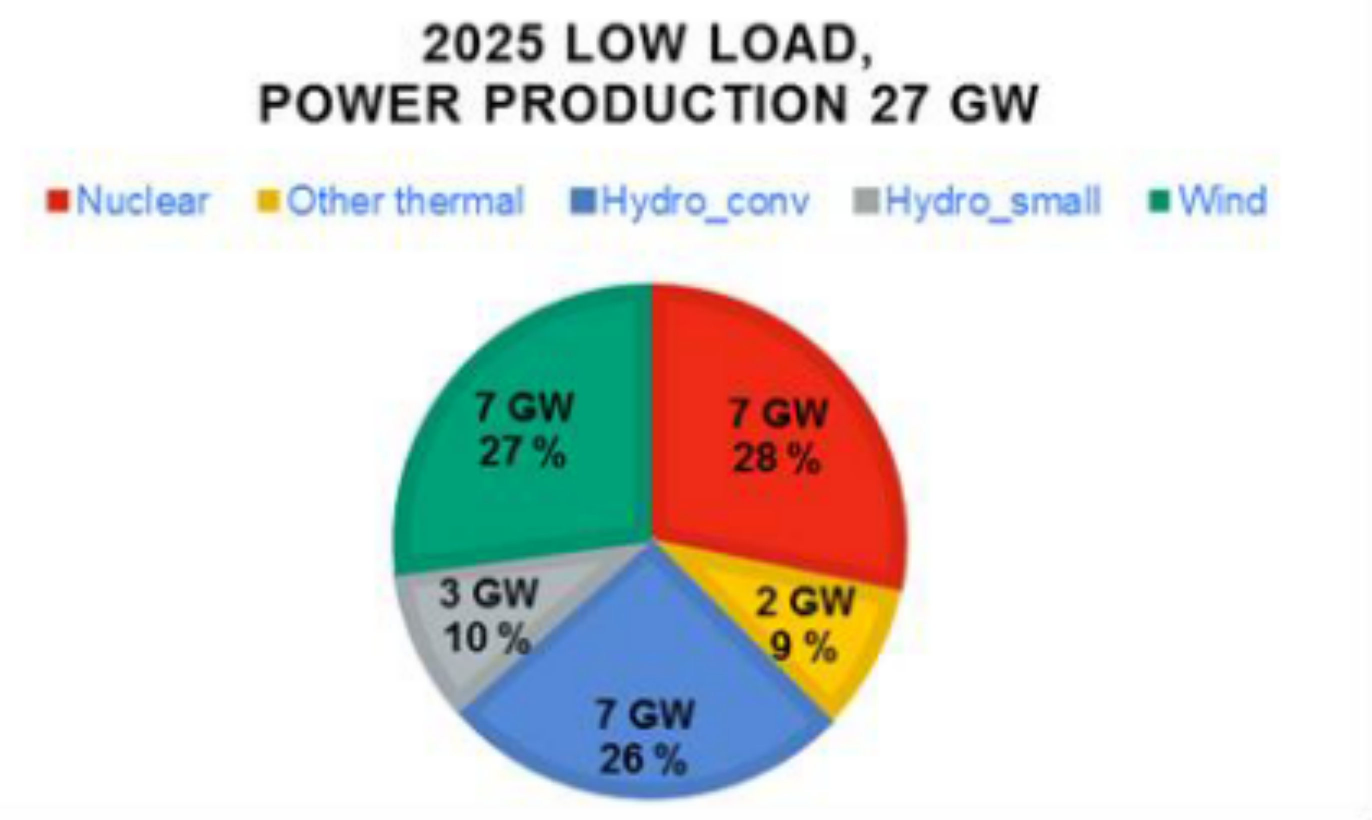
FIGURE 4.8: ESTIMATED KINETIC ENERGY IN SWEDEN, FINLAND AND NORWAY

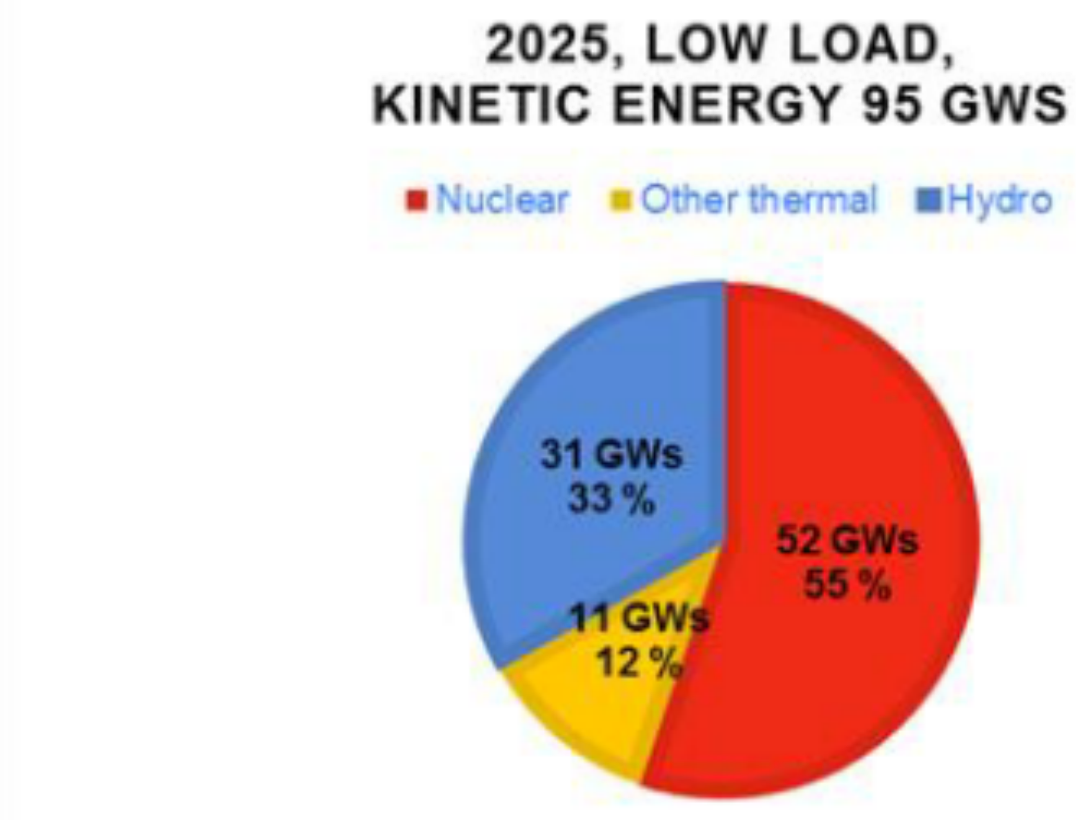
Future inertia during high load





Future inertia during low load





Handling low inertia situations

- In May 2019 the Inertia 2020-project will publish a position paper detailing how we deal with art. 39 (3).
- In the Nordics it has already been concluded that there is no need for defining minimum inertia.
- Frequency stability during low inertia will be maintained by the following measures:
  - inertia monitoring
  - reduction of reference incident
  - new requirements for frequency containment reserves (FCR)
  - introducing new product: fast frequency reserve (FFR)

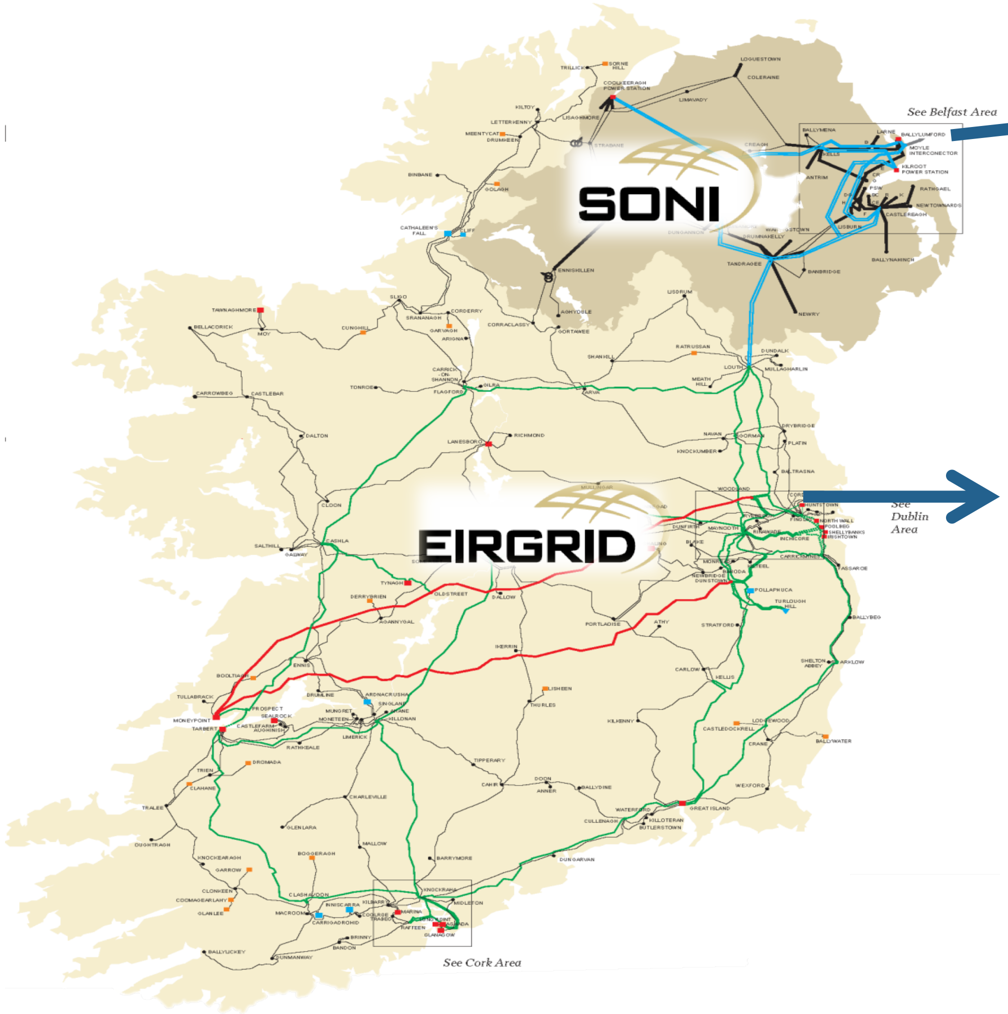
DSA activities in RG Ireland & Northern Ireland

DSA stakeholder workshop on SOGL A38-39

Marta Val Escudero

Brussels May 15 2018

The All-Island System (RG IE/NI)



Moyle Interconnector to Scotland (500MW)

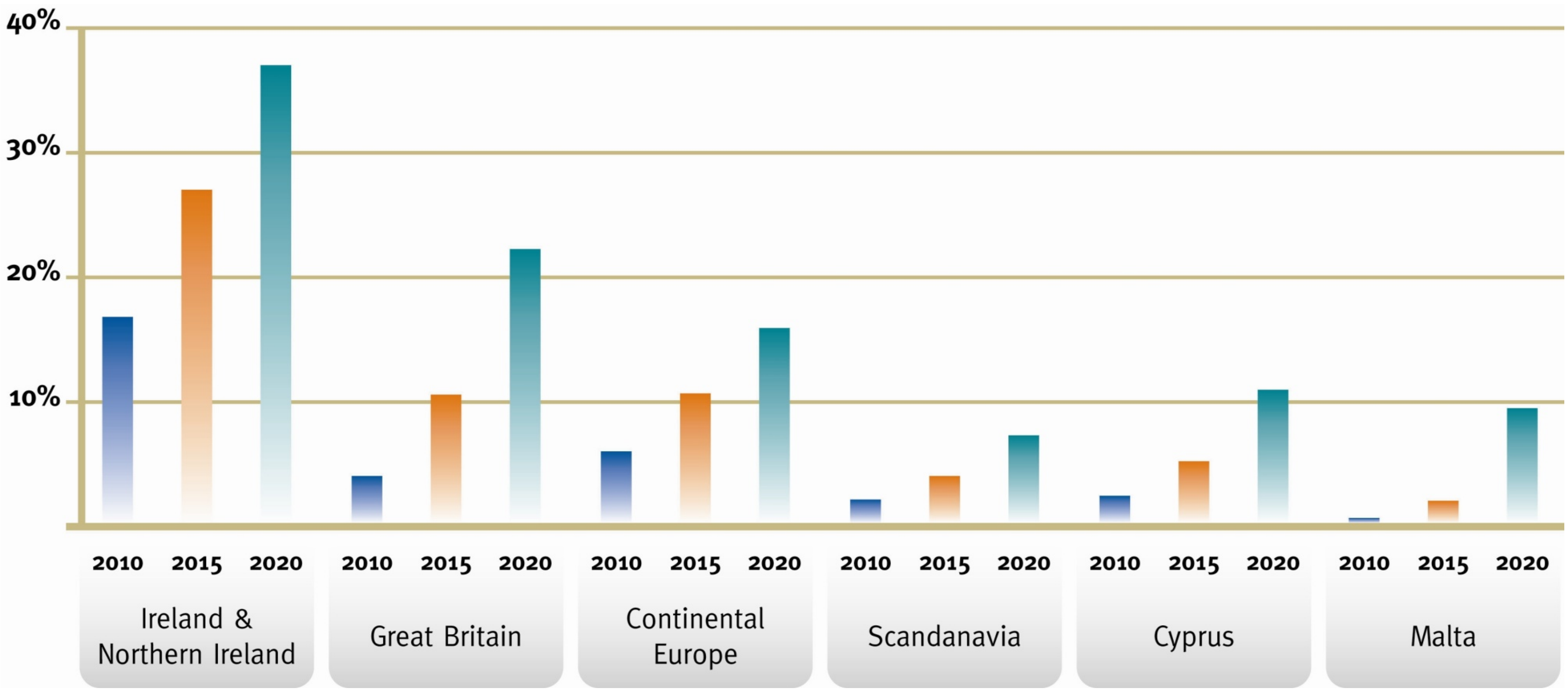
East West Interconnector to Wales (500MW)

SONI System Operator Northern Ireland

EIRGRID System Operator Ireland

semo Single Electricity Market Operator — Market Operator All-Island

2020 RES-E (Wind) Targets

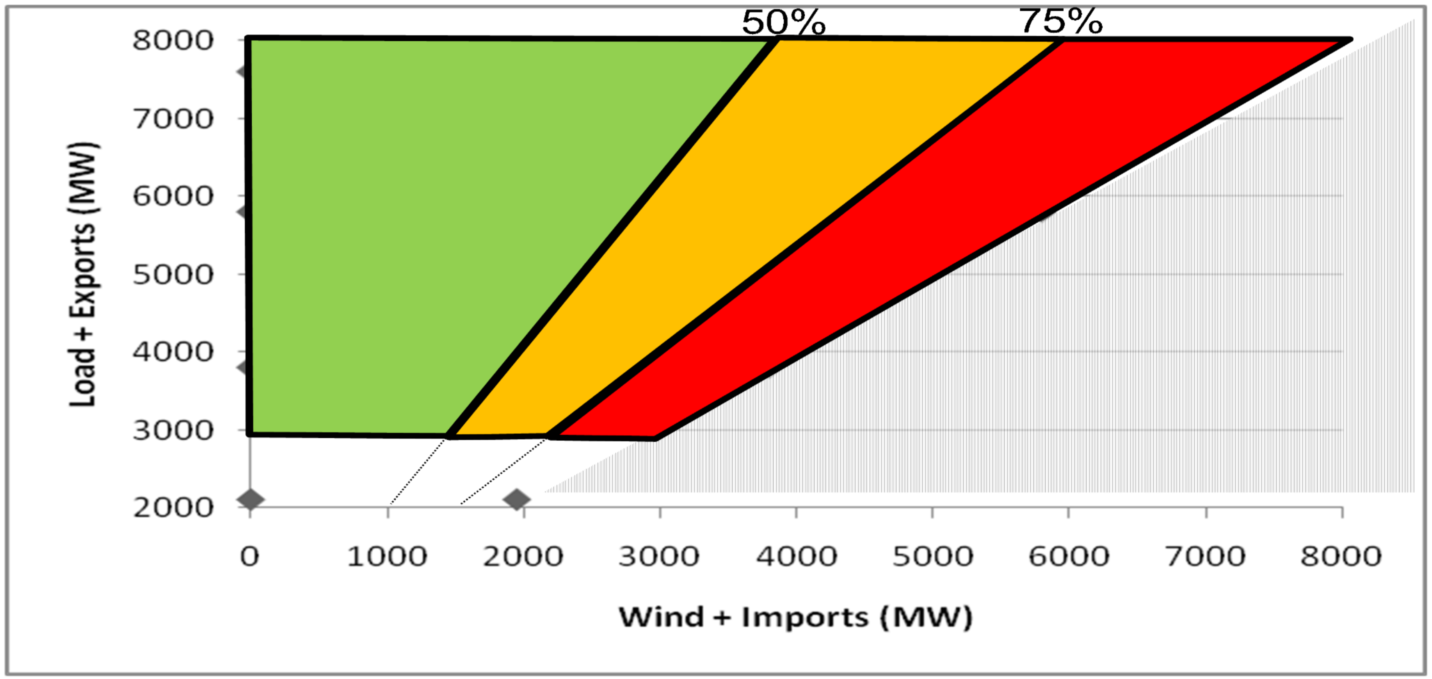


* Based on analysis of National Renewable Energy Action Plans (NREAPs) as submitted by EU Member States

All-Island Operational Metrics

- SNSP ≤ 65%
- RoCoF ≤ 0.5 Hz/s
- Inertia ≥ 23 GW.s
- On-Line Synchronous units ≥ 8

System **N**on-**S**ynchronous **P**enetration (SNSP)



$$\text{SNSP} = \frac{\text{Wind + Imports}}{\text{Demand + Exports}}$$

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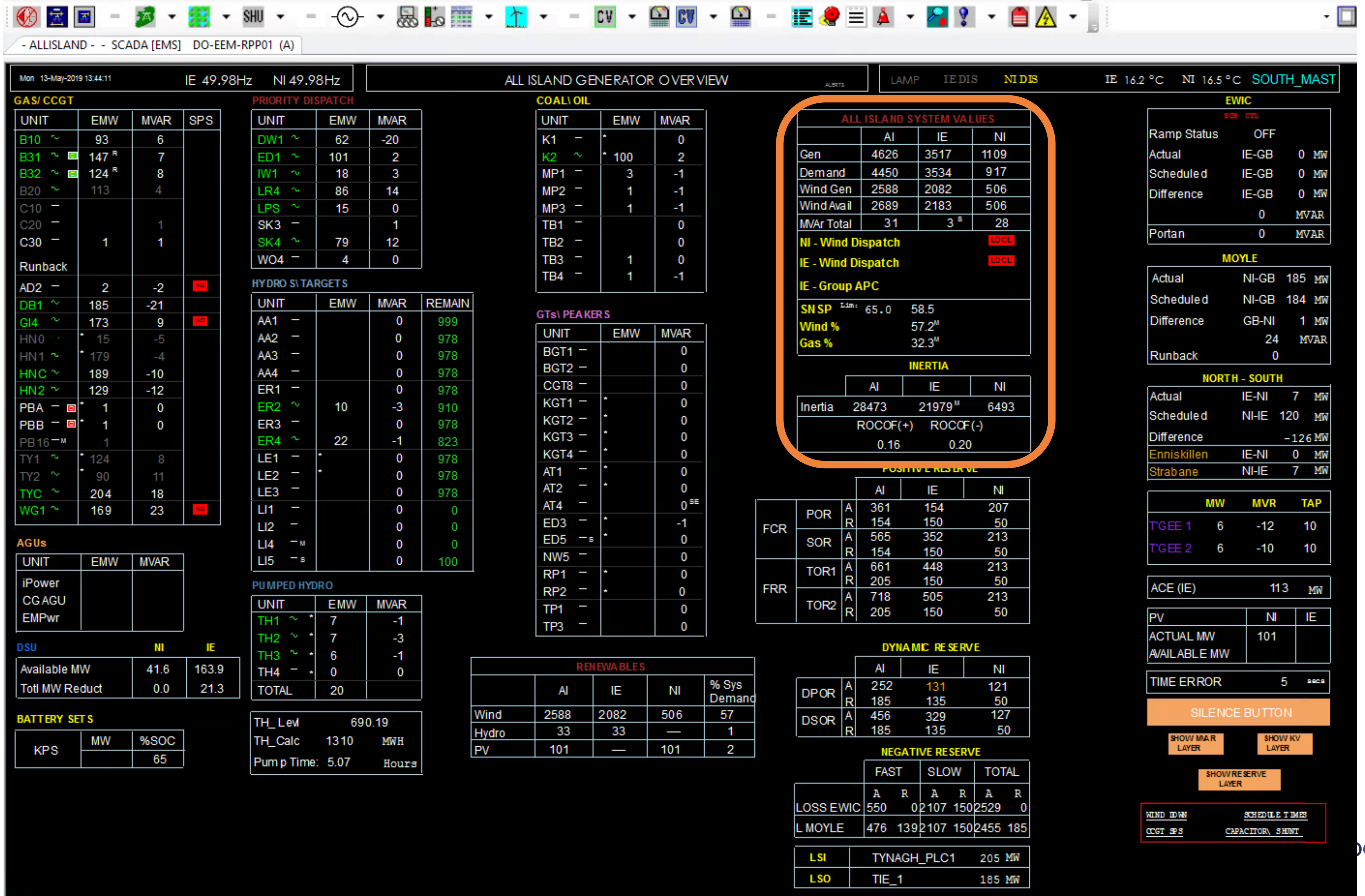
Co-Ordination in RG IE/NI

Integrated Energy Management System:

SONI

EIRGRID

- Inertia, RoCoF and SNSP monitored on an All-Island basis
- Static and Dynamic Security Assessment performed on an All-Island basis


- ALLISLAND - - SCADA [EMS] DO-EEM-RPP01 (A)
Mon 13-May-2019 13:44:11
IE 49.98Hz NI 49.98Hz
ALL ISLAND GENERATOR OVERVIEW
LAMP IE DIS NI DIS
IE 16.2 °C NI 16.5 °C SOUTH_MAST
GAS/ CCGT
UNIT EMW MVAR SPS
B10 93 6
B31 147 R 7
B32 124 R 8
B20 113 4
C10
C20 1
C30 1 1
Runback
AD2 2 -2
DB1 185 -21
GI4 173 9
HN0 15 -5
HN1 179 -4
HNC 189 -10
HN2 129 -12
PBA 1 0
PBB 1 0
PB16 1
TY1 124 8
TY2 90 11
TYC 204 18
WG1 169 23
AGUs
UNIT EMW MVAR
iPower
CG AGU
EMPwr
DSU NI IE
Available MW 41.6 163.9
Totl MW Reduct 0.0 21.3
BATTERY SETS
KPS MW %SOC 65
PRIORITY DISPATCH
UNIT EMW MVAR
DW1 62 -20
ED1 101 2
IW1 18 3
LR4 86 14
LPS 15 0
SK3 1
SK4 79 12
WO4 4 0
HYDRO S\ TARGETS
UNIT EMW MVAR REMAIN
AA1 0 999
AA2 0 978
AA3 0 978
AA4 0 978
ER1 0 978
ER2 10 -3 910
ER3 0 978
ER4 22 -1 823
LE1 0 978
LE2 0 978
LE3 0 978
LI1 0 0
LI2 0 0
LI4 0 0
LI5 0 100
PUMPED HYDRO
UNIT EMW MVAR
TH1 7 -1
TH2 7 -3
TH3 6 -1
TH4 0 0
TOTAL 20
TH_Lev 690.19
TH_Calc 1310 MWH
Pump Time: 5.07 Hours
COAL\ OIL
UNIT EMW MVAR
K1 0
K2 100 2
MP1 3 -1
MP2 1 -1
MP3 1 -1
TB1 0
TB2 0
TB3 1 0
TB4 1 -1
GTs\ PEAKERS
UNIT EMW MVAR
BGT1 0
BGT2 0
CGT8 0
KGT1 0
KGT2 0
KGT3 0
KGT4 0
AT1 0
AT2 0
AT4 0
ED3 -1
ED5 0
NW5 0
RP1 0
RP2 0
TP1 0
TP3 0
RENEWABLES
AI IE NI % Sys Demand
Wind 2588 2082 506 57
Hydro 33 33 — 1
PV 101 — 101 2
ALL ISLAND SYSTEM VALUES
AI IE NI
Gen 4626 3517 1109
Demand 4450 3534 917
Wind Gen 2588 2082 506
Wind Avail 2689 2183 506
MVAr Total 31 3 28
NI - Wind Dispatch LOCL
IE - Wind Dispatch LOCL
IE - Group APC
SNSP Lim: 65.0 58.5
Wind % 57.2
Gas % 32.3
INERTIA
AI IE NI
Inertia 28473 21979 6493
ROCOF(+) ROCOF(-)
0.16 0.20
POSITIVE RESERVE
AI IE NI
FCR POR A 361 154 207
R 154 150 50
SOR A 565 352 213
R 154 150 50
FRR TOR1 A 661 448 213
R 205 150 50
TOR2 A 718 505 213
R 205 150 50
DYNAMIC RESERVE
AI IE NI
DPOR A 252 131 121
R 185 135 50
DSOR A 456 329 127
R 185 135 50
NEGATIVE RESERVE
FAST SLOW TOTAL
A R A R A R
LOSS EWIC 550 0 2107 150 2529 0
L MOYLE 476 139 2107 150 2455 185
LSI TYNAGH_PLC1 205 MW
LSO TIE_1 185 MW
EWIC
Ramp Status OFF
Actual IE-GB 0 MW
Scheduled IE-GB 0 MW
Difference IE-GB 0 MW
0 MVAR
Portan 0 MVAR
MOYLE
Actual NI-GB 185 MW
Scheduled NI-GB 184 MW
Difference GB-NI 1 MW
24 MVAR
Runback 0
NORTH - SOUTH
Actual IE-NI 7 MW
Scheduled NI-IE 120 MW
Difference -126 MW
Enniskillen IE-NI 0 MW
Strabane NI-IE 7 MW
MW MVR TAP
T'GEE 1 6 -12 10
T'GEE 2 6 -10 10
ACE (IE) 113 MW
PV NI IE
ACTUAL MW 101
AVAILABLE MW
TIME ERROR 5 secs
SILENCE BUTTON
SHOW MVAR LAYER
SHOW KV LAYER
SHOW RESERVE LAYER
WIND DOWN
SCHEDULE TIMES
CCGT SPS
CAPACITOR\ SHUNT

SO GL Article 38(2)

Dynamic stability monitoring and assessment

2. Each TSO shall perform a dynamic stability assessment at least once a year to identify the stability limits and possible stability problems in its transmission system. All TSOs of each synchronous area shall coordinate the dynamic stability assessments, which shall cover all or parts of the synchronous area.

Implementation of SO GL Article 38(2)

Wind Dynamic Security Assessment Tool (WSAT) performs dynamic stability assessments on an All-Island basis.

- On-Line security assessments are performed every 5 minutes (24/7 – 365).
- On-Line security assessments include voltage, frequency and rotor-angle stability.
- Small-signal stability analysis are performed off-line.
- One single All-Island dynamic model is shared between both System Operators. Special Protection Schemes (SPS) are integrated in the model.
- Contingencies include loss of largest generation units and HVDC interconnectors, system separation and network faults on an All-Island basis.

Requirements for performing studies and TSO co-ordination are fulfilled

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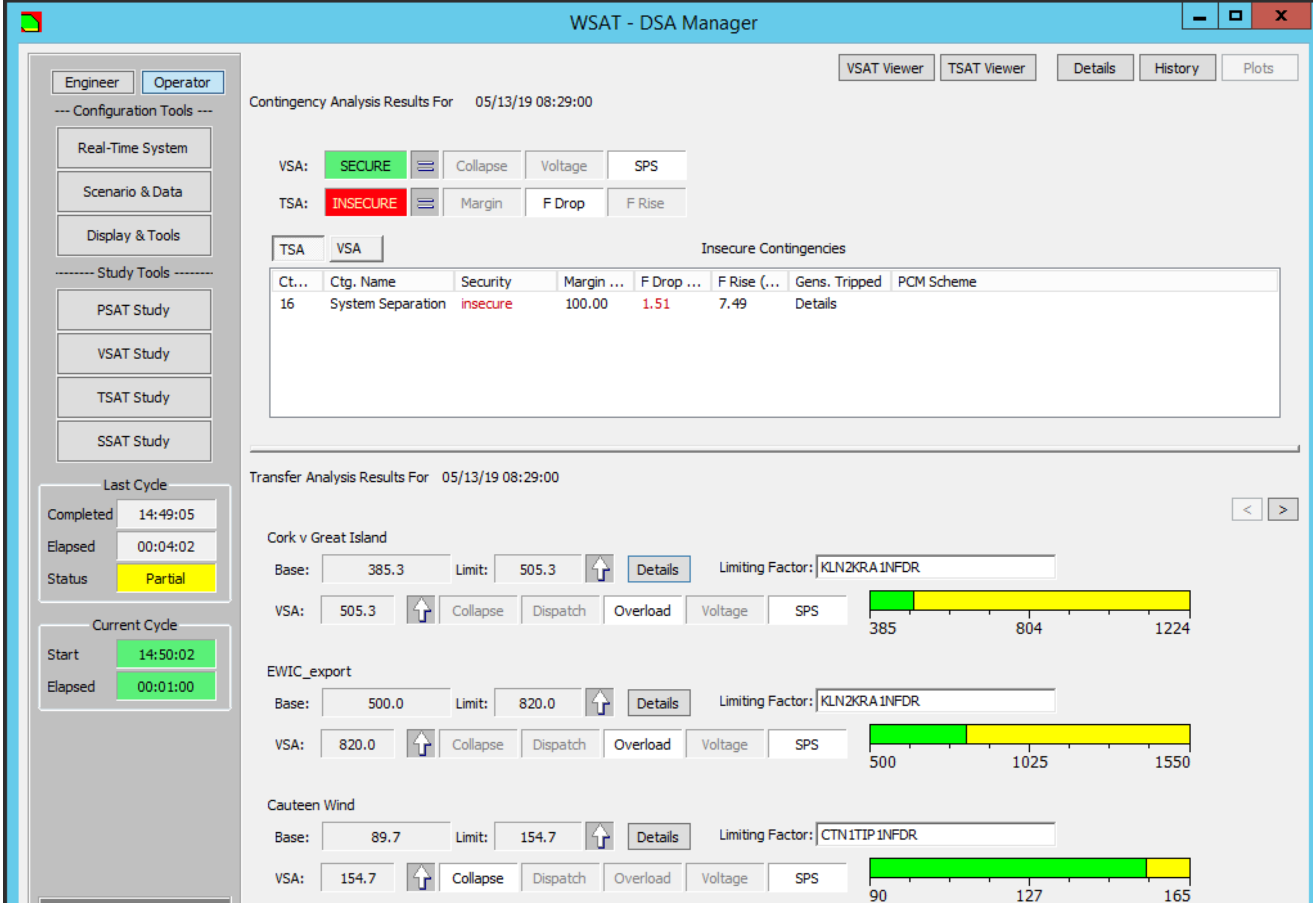
WSAT - DSA Manager
Engineer
Operator
--- Configuration Tools ---
Real-Time System
Scenario & Data
Display & Tools
-------- Study Tools --------
PSAT Study
VSAT Study
TSAT Study
SSAT Study
Last Cycle
Completed 14:49:05
Elapsed 00:04:02
Status Partial
Current Cycle
Start 14:50:02
Elapsed 00:01:00
VSAT Viewer
TSAT Viewer
Details
History
Plots
Contingency Analysis Results For 05/13/19 08:29:00
VSA: SECURE Collapse Voltage SPS
TSA: INSECURE Margin F Drop F Rise
TSA VSA
Insecure Contingencies
Ct... Ctg. Name Security Margin ... F Drop ... F Rise (... Gens. Tripped PCM Scheme
16 System Separation insecure 100.00 1.51 7.49 Details
Transfer Analysis Results For 05/13/19 08:29:00
Cork v Great Island
Base: 385.3 Limit: 505.3 Details Limiting Factor: KLN2KRA 1NFDR
VSA: 505.3 Collapse Dispatch Overload Voltage SPS
385 804 1224
EWIC_export
Base: 500.0 Limit: 820.0 Details Limiting Factor: KLN2KRA 1NFDR
VSA: 820.0 Collapse Dispatch Overload Voltage SPS
500 1025 1550
Cauteen Wind
Base: 89.7 Limit: 154.7 Details Limiting Factor: CTN1TIP 1NFDR
VSA: 154.7 Collapse Dispatch Overload Voltage SPS
90 127 165

SO GL Article 39(3)

Dynamic stability management

3. In relation to the requirements on minimum inertia which are relevant for frequency stability at the synchronous area level:

(a) all TSOs of that synchronous area shall conduct, not later than 2 years after entry into force of this Regulation, <u>a common study per synchronous area to identify whether the minimum required inertia needs to be established</u>, taking into account the costs and benefits as well as potential alternatives. All TSOs shall notify their studies to their regulatory authorities. All TSOs shall conduct a periodic review and shall update those studies every 2 years;

(b) where the studies referred to in point (a) demonstrate the need to define minimum required inertia, <u>all TSOs from the concerned synchronous area shall jointly develop a methodology for the definition of minimum inertia required to maintain operational security and to prevent violation of stability limits</u>. That methodology shall respect the principles of efficiency and proportionality, be developed within 6 months after the completion of the studies referred to in point (a) and shall be updated within 6 months after the studies are updated and become available; and

(c) each <u>TSO shall deploy in real-time operation the minimum inertia in its own control area</u>, according to the methodology defined and the results obtained in accordance with paragraph (b).

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Implementation of SO GL Article 39(3)

Current Practice

- “Minimum Number of Units” study (2014) identified the need for minimum inertia requirements.
- Operational Policy defines an All-Island Inertia Floor of 23 GW.s.
- Minimum Inertia is a constraint in generation scheduling.
- New System Services have been introduced to help manage the system with low inertia: Synchronous Inertial Response (SIR), Fast Frequency Response (FFR).
- System Inertia is monitored in real-time based on on-line synchronous generation.
- On-Line Dynamic Stability assessment (WSAT) identifies any violation to security criteria in real-time and suggests remedial actions.

Current operational practice fulfils the requirements

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Implementation of SO GL Article 39(3)

Next Steps to meet 2020 40% RES-E target

- **Target to achieve 75% SNSP operation in 2020**
- **Technical Studies scheduled in Q3/Q4 2019 to facilitate changes in operational metrics**
  - **RoCoF**: increase from 0.5 Hz/s to 1 Hz/s
  - **Inertia Floor**: reduction from 23 GW.s to 20 GW.s and then to 17.5 GW.s
  - **SNSP**: increase from 65% to 70% and then to 75%
- **Process: Studies ➔ Policy Review ➔ Trial ➔ Implementation**
- **New Decision Support Tools**

LSAT
(Look-ahead Security Assessment Tool)

- Decision Support Tool in Control Centres
- Real time system security analysis
- Forward looking security analysis
- Required to increase SNSP beyond 65%

DSA Stakeholder Workshop

RG GB activities

Susan Mwape, National Grid ESO

Dynamic stability monitoring and assessment requirements (Art.38)

- A suite of programs are used for offline studies from long term to day ahead
- Online studies to determine post-fault transient and dynamic stability issues in real time
- Studies are driven by: circuit availability, large synchronous plant availability, HVDC flows, voltage issues, thermal limits, outage patterns
- Remedial actions include bids and offers, generation load reduction, interconnector trades, emergency instructions, raising system voltage
- NGET does not currently exchange dynamic stability studies with other TSOs

System operational security standards

For the following faults…

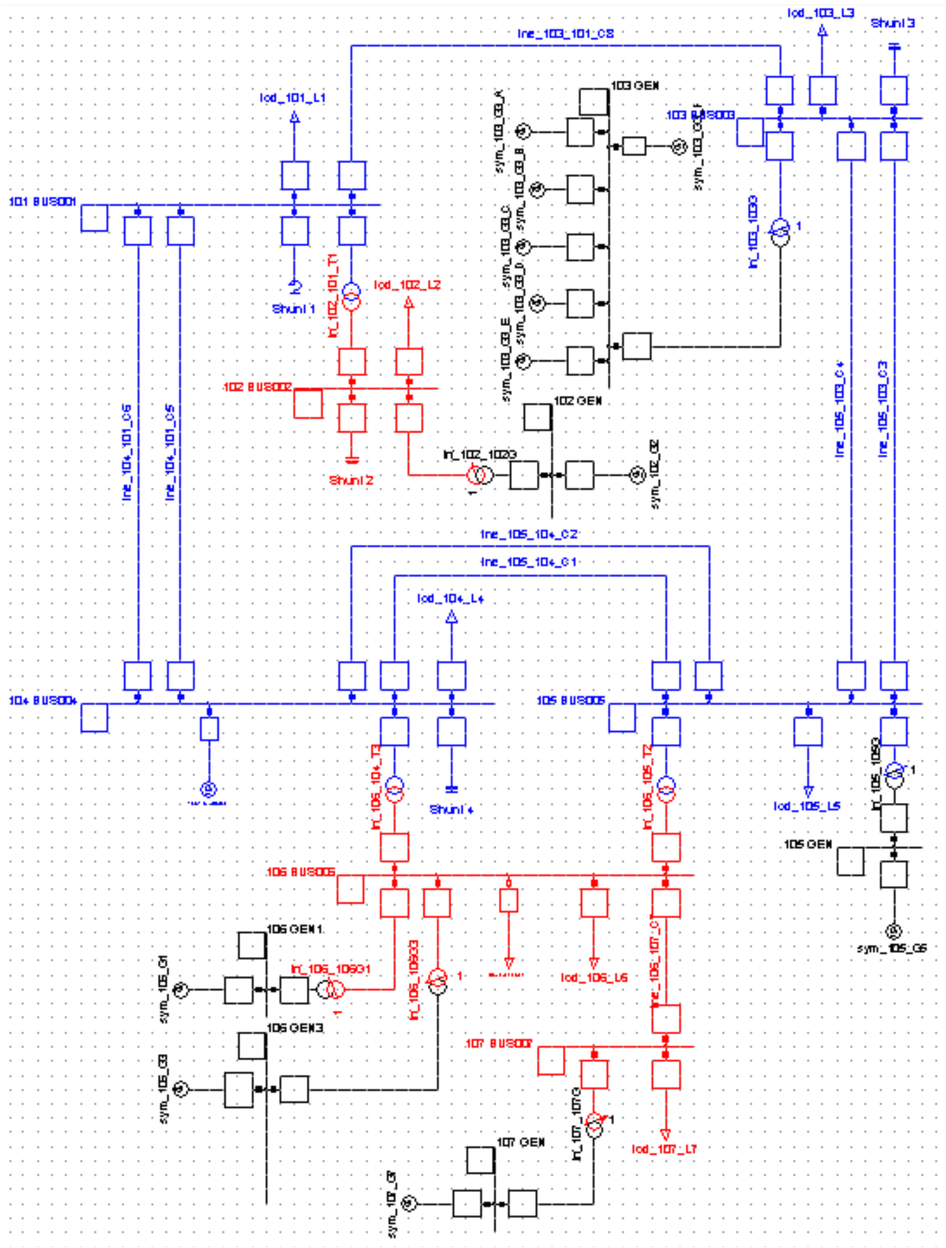
- Single circuit cable or overhead line
- Double circuit overhead line
- Busbar or mesh corner
- Supergrid transformer
- Reactive compensator
- The most onerous single system infeed

There shall not be:

- A loss of supply
- Permanent change in frequency below 49.5Hz or above 50.5Hz
- Unacceptable overloading of transmission apparatus
- Unacceptable high or low voltage conditions
- System instability

Network stability studies

- Simplified GB system representation
- Post fault transient angular and dynamic stability is assessed for most credible contingencies
- Tool flags credible contingencies as insecure if transient stability criteria is not met



Dynamic stability monitoring and assessment (Art.38)

SOGL Article number	Current approach in GB
38.1 and 38.2	Dynamic assessment is already carried out
38.3 and 38.4	NGET is sole entity with SO responsibility for coordinated dynamic stability in GB synchronous area
38.5	Not relevant for GB synchronous area as transmission system is not AC-interconnected
38.6	Dynamic assessment rules specific to GB synchronous area

Dynamic stability management requirements (Art 39)

- To date studies are based on energy balancing and power factory scenarios
- In both cases it's clear that inertia has a significant effect on the rate of change of system frequency and the minimum frequency achieved.
- Reducing the largest credible loss reduces the maximum potential RoCoF following a loss
  - Increasing system inertia is less effective than reducing the largest loss
- Frequency Response requirements are driven by:
  - Synchronous demand, system inertia, Rate of change of frequency, largest loss, frequency limits

Dynamic stability management (Art.39)

Article number	NGET compliance
39.1	In the case of violation of stability limits, NGET has a process to carry out remedial actions
39.2	Process for clearing faults in time is calculated through dynamic system assessment
39.3	Current studies are based on reduction of largest loss, there is no set minimum inertia. - Minimum inertia study?