European Power System 2040

Completing the map

System Dynamics and Operational Challenges

entsoe

Reliable Sustainable Connected

1.3

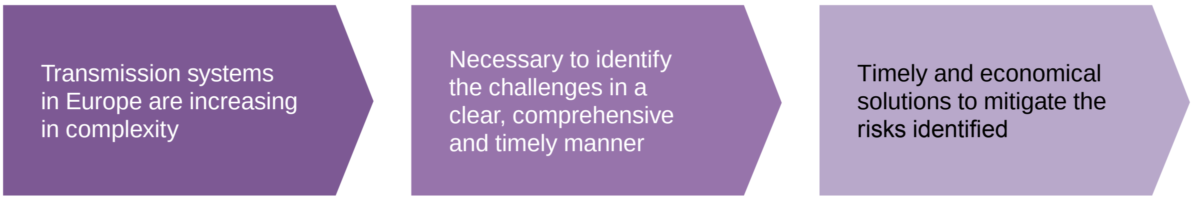
System dynamic and operational challenges

1.3.1 Conclusion

This Appendix presents an in-depth analysis of the conditions that System Operators will be meeting when managing the grid in 2040. An overview of this study is presented in Chapter 5 of the main report. Transmission systems in Europe are increasing in complexity. Conventional generation is being displaced by new generation technologies that have different performance capabilities, generation is moving from the higher voltage levels to the distribution network, and there is an increased level of interconnection between different synchronous areas.

The power flow profile between different TSO areas is also changing. European market integration, increased interconnection, and the variability of renewable generation output are driving higher and more variable power transits across long power corridors. This increases both: the interdependency of TSOs, processes to operate the system in a secure and efficient manner as well as the need to take into account the challenges associated with the operation of the future system when designing the transmission network.

In order to address the challenges associated with the increased complexity of the power system, TSOs need to systematically assess the long-term changes in various operational parameters such as inertia and short-circuit current levels, operational requirements such as flexibility, and availability of ancillary services such as reactive power support, frequency response, and contribution to short-circuit current. This assessment should form the foundations to help to implement timely and economical solutions or measures to mitigate the risks identified.



This chapter includes results of the analysis of the hourly demand and generation profiles produced by the TYNDP 2018 market studies for all scenarios. These results provide insight into the operational challenges and trends in synchronous areas and countries.

The chapter also includes information collected from all TSOs regarding main concerns on more local/regional issues. This information helps to identify which issues are common among several TSOs and which ones would benefit from coordinated solutions.

Aspects related to frequency, flexibility needs to cope with the displacement of controllable generation, impact of high RES penetration on transient and voltage stability and other additional challenges, together with the corresponding mitigation measures are described in the following sub-chapters.

1.3.2 Frequency related aspects

Results are obtained based on the outputs of the market modelling studies in all the TYNDP scenarios:
— Sustainable Transition: ST2030, ST2040
— Global Climate Action: GCA2040
— Distributed Generation: DG2030, DG2040
— European Commission policy scenarios: EUCO2030.

Trends in system inertia and Rate of Change of Frequency

Frequency variations occur in power systems due to mismatches between active power generation and demand. Once a mismatch takes place, the energy stored in the rotating masses of the synchronous generating units, by virtue of their inertia, provides means of instantaneously balancing any mismatch between the raw energy supplied to generating units and the total system demand including losses. The immediate inertial response results in a change in rotor speeds and, consequently, the system frequency.

Whereas this does not solve the power mismatch problem in a sustainable manner, it is essential for instantaneously balancing this mismatch until frequency reserve response providers (see Box 1) are able to respond to the change of frequency and vary the power output of their plants to restore the balance between generation and demand.

Box 1: Frequency management – Frequency containment, restoration and replacement reserves

To restore the frequency to its nominal value after a frequency variation resulting from a generation-consumption imbalance, a number of balancing services providers are required sequentially over time to ensure adequate frequency response. Those providers will vary the power output of their plants to restore the balance between generation and demand. This response is not affected by inertia. It also will have no impact on the initial ROCOF.

Article 3 of System Operation Guidelines (SO GLs) establishes the following terminology:

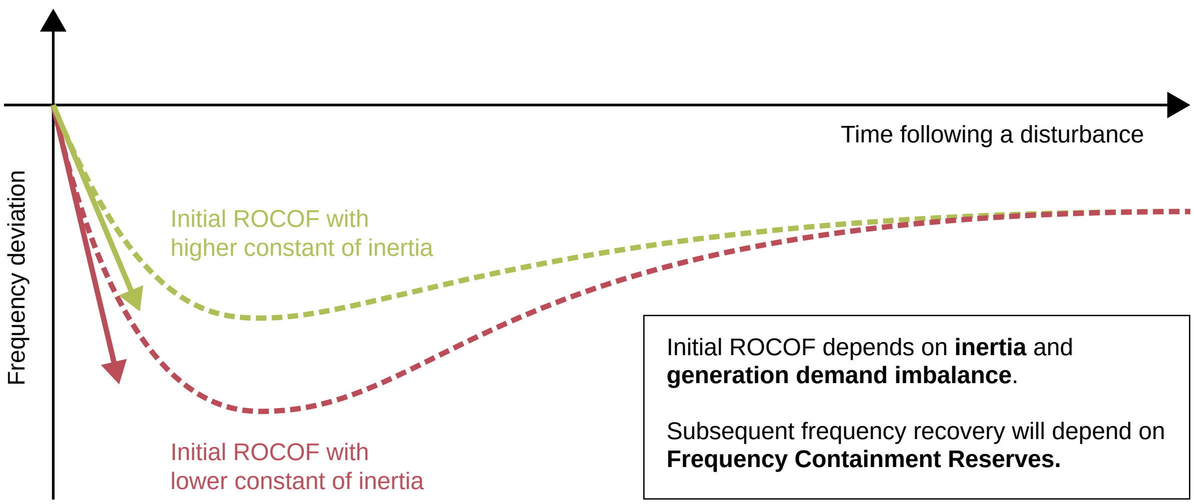
— "'frequency containment reserves (FCR)' means the active power reserves available to contain system frequency after the occurrence of an imbalance;
— 'frequency restoration reserve (FRR)' means the active power reserves available to restore system frequency to the nominal frequency and for synchronous area consisting of more than one LFC area power balance to the scheduled value;
— 'replacement reserves (RR)' means the active power reserves available to restore or support the required level of FRR to be prepared for additional system imbalances, including generation reserves;"

Duration and extent over time of frequency excursions depend on the magnitude of the frequency reserves and also on the performance of primary, secondary and tertiary frequency regulation systems. The exchange of reserves between interconnected countries and the coordination at national level of new balancing service providers connected at the distribution network completes the operational challenge.

The initial Rate of Change of Frequency (ROCOF) and the magnitude of the frequency deviation depend on the mismatch between generation and demand compared to the size of the system. The initial ROCOF is also dependent on the total stored kinetic energy (depending on the system inertia) at the time the imbalance took place, as well as on the frequency dependency of the load (self-regulation effect). Basically, the higher the imbalance between load and generation and the lower the inertia, the higher the ROCOF is.

The high ROCOF reduces the required time to deploy the necessary fast balancing actions and, additionally, for some units, could lead to disconnection and, therefore, further deterioration of system security. With very low inertia, the system would experience high frequency excursions and may even blackout as result of a relatively low mismatch between generation and demand.

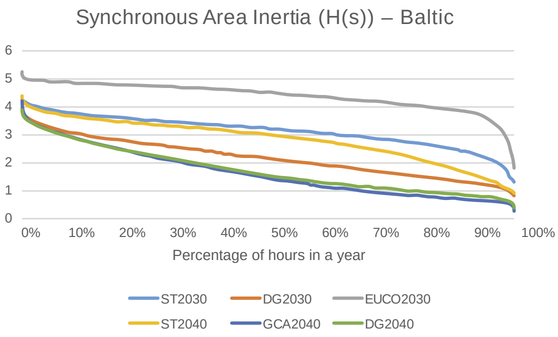
Figure 10: Rate of Change of Frequency depending on inertia

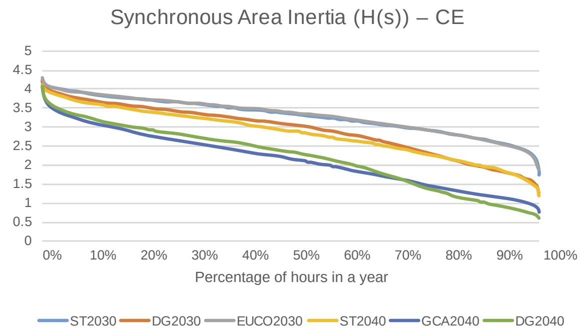


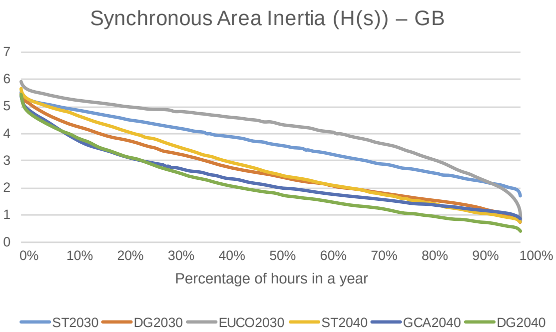
Taking into account the TYNDP 2018 market results, the duration curves in Figure 11 present the percentage of hours in a full year where, for all Synchronous Areas, the intrinsic inertia from generators is above a given value.

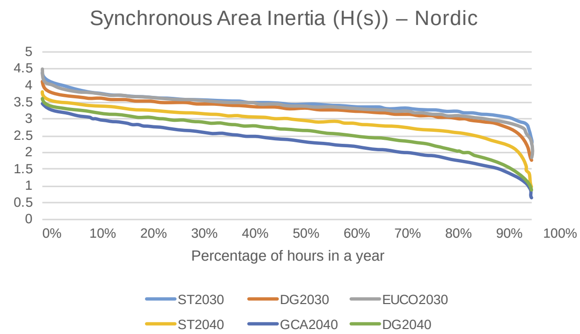
This estimated equivalent system inertia H(s) is calculated on the basis of online generators' capacity. Inertia contribution from demand is neglected because it is very small.

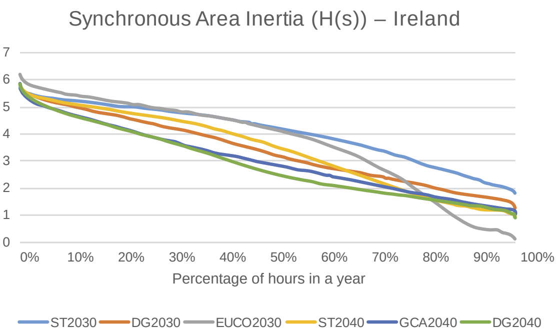
Figure 11: Duration curves of estimated synchronous areas equivalent inertia (H(s))











System inertia trends

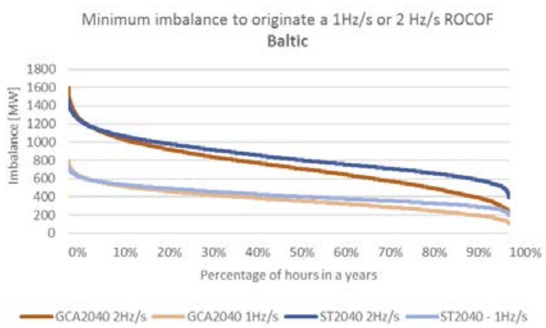
As we move from the situations in 2030 to the 2040 visions with a higher integration of RES and more distributed generation, inertia in all synchronous areas will decrease. The reduction is noticeable even in a large area such as Continental Europe.

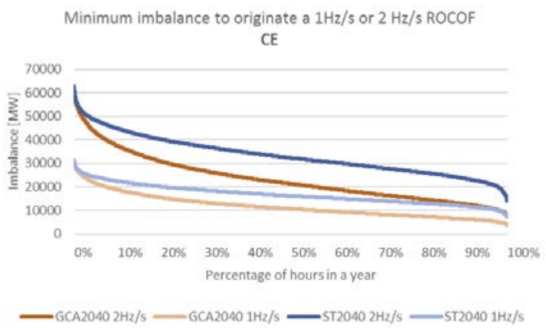
With very low inertia, the system becomes more vulnerable to experience high frequency excursions and even blackout as result of a relatively low mismatch between generation and demand. The impact of this inertia reduction is especially significant in small synchronous areas.

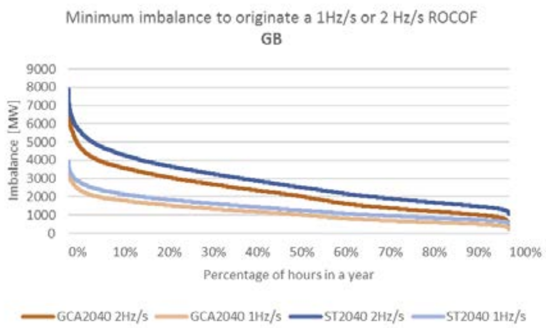
The figures in Figure 12 present the minimum imbalance necessary to trigger a fixed ROCOF for all the hours of the year in the different synchronous areas using the estimated values of inertia. As previously described above, the initial ROCOF depends on the imbalance between load and generation and the intrinsic inertia of the system at the time when the disturbance takes place. The following assumptions were taken on the illustrative calculations:

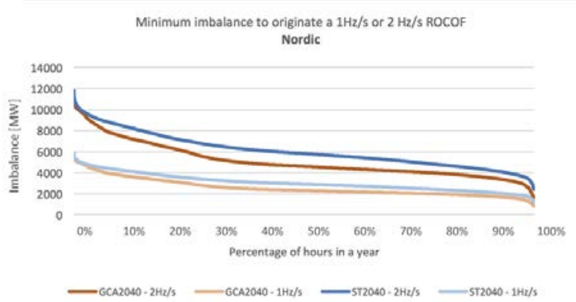
— Two scenarios are used: a situation with low RES, Sustainable transition 2040, and a situation with high RES, Global Climate Action 2040.
— Two ROCOF values are used: 1 Hz/s and 2 Hz/s. The higher, 2 Hz/s, representing a typical value for defence plans and RfG withstand capability for generators.

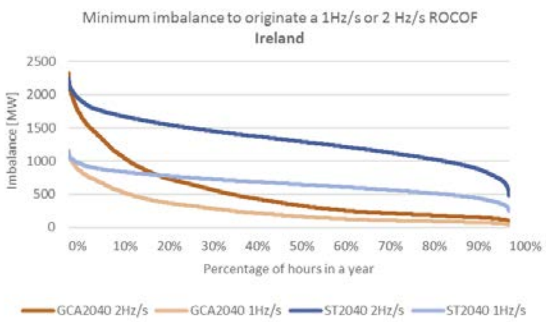
Figure 12: Duration curves of estimated synchronous areas minimum imbalance that would originate a given ROCOF











ROCOF trends

Given the trend of more non-synchronous sources without intrinsic inertia, frequency sensitivity (ROCOF and frequency excursion) to generation-demand imbalance will increase. This is emphasised in scenarios with high integration of RES.

Small synchronous areas would see rapid and large frequency excursions following a normal generation loss, large synchronous areas would not see the same size of frequency excursions unless a significant disturbance occurs such as a system split.

As a general rule, the larger the imbalance is, the higher the ROCOF would be, and for a same triggering incident, higher ROCOF is attained in low inertia scenarios.

The loss of generation necessary to trigger a certain level of ROCOF is higher in large synchronous areas compared to that in small synchronous areas. For example under certain conditions, a 0.5GW loss in Ireland would be sufficient to trigger the same ROCOF as a 40GW loss in Continental Europe. As a consequence, whereas small synchronous areas would see large and rapid frequency excursions that could last for several tens of seconds after a normal generation loss, large synchronous areas would not see the same size of frequency excursions unless a significant disturbance occurs such as a system split event which would largely exceed the normative incident (3000MW for CE).

Given the trend of more non-synchronous sources without intrinsic inertia, higher frequency sensitivity (ROCOF and frequency excursion) to incidents implying generation-demand imbalances should be monitored. Furthermore, a high penetration of inverter-supplied loads also increases the frequency independence of the demand. A decrease of the self-regulation effect increases the effort of balancing the power imbalance. In all cases, frequency sensitivity (ROCOF and frequency excursion) to generation-demand imbalance incidents is expected to increase.

The performed analysis of the trends portrayed by the long-term TYNDP scenarios, does not try to find infeasible or unacceptable situations, it rather provides a factual explanation of their related challenges and a basis from where the necessary measures, that make sure the system is secured, can be derived.

Localised frequency variations

Frequency assessment (ROCOF, maximum deviation, stability) is typically performed at the synchronous area level. However, this approach misses two important aspects:

— System split events – in such events, the frequency varies drastically inside the resulting islands.
— Local transient frequency variations that would typically take place following an imbalance prior to the frequency converging to the same value across the synchronous area.

In a system split event the synchronous area splits into separate islands. The exports and imports between these islands, prior to the system split event, turn into power imbalances for the separate islands after the split. The larger the export or import of the island before the split, the greater the imbalance after the split and therefore the greater the need for large and quick adjustment for generation and demand. It is impossible to exactly predict the borders of potential system splits and their aftermath.

The analysis of inertia by country brings further insight on the level of complexity in a system split event. Not only the resulting imbalances are difficult to predict, but also the resulting equivalent system inertia will differ from country to country and sets of countries depending on the point in time.

It is noted that a system split is more prone to occur across congested transit corridors and thus interrupting these transits. As transits are increasing in magnitude, distance, and volatility, the power imbalance following a system split event is likely to increase. This would consequently lead to larger, longer, and quicker frequency excursions in subsequently formed islands. The increased imbalance has to be compensated by Low Frequency Demand Disconnection (LFDD) or fast frequency response. Defence plans[7] are designed to help during severe disturbances but cannot stabilise all system split scenarios with extreme imbalances. Potentially needed restoration plans will employ adequate resources to stabilise the islands and later synchronise the system.

[7] According to the Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation: system defence plan means the technical and organisational measures to be undertaken to prevent the propagation or deterioration of a disturbance in the transmission system, in order to avoid a wide area state disturbance and blackout state.

Potential mitigation measures

Different solutions and mitigation measures contribute to securing the power system performance in case of disturbances related to frequency:

- Implementation of the Connection Codes: they will be essential to ensure that the necessary technical requirements from generators, HVDC and demand related to synthetic inertia, frequency sensitive mode and robustness against high ROCOF are implemented.
- Immediate inertial response can only be presently met by synchronous generators. After immediate inertial response, fast frequency response by other sources than synchronous generation are needed: converter-connected generation, demand side response, storage (including batteries), and reserves shared between synchronous areas using HVDC.
- In the future new capabilities, not yet available, such as grid-forming converters[8] are currently promising to be capable of providing immediate inertial response. Grid forming converters will need research and development so they could prove to be a solution and can in the future be incorporated in the grid[9].
- Large imbalances will become increasingly more challenging to secure and is an issue with cross-border impact: particularly in smaller synchronous areas, constraining cross-border trade with larger synchronous areas, such that the largest secured imbalance does not result in high ROCOF.
- Use the contribution of synchronous compensators (SCs): decoupling generators to become SCs under changing operating conditions in real time from generators such as GTs and CCGTs or permanently from decommissioned nuclear power plants (Germany).
- Real-time monitoring of system inertia to ensure minimum level of inertia is in the system at all times.
- Procurement of inertia as an ancillary service and activation when necessary (e.g. during high RES production).
- Constraining RES and placing synchronous generation with intrinsic inertia in the unit commitment. This measure, which is easy to implement as a short-term solution could be less efficient in the long term. This constraint can be in the form of redispatch.

[8] Implementation Guiding Document – High Penetration of Power Electronic Interfaced Power Sources. https://www.entsoe.eu/Documents/Network%20codes%20documents/Implementation/CNC/170322_IGD25_HPoPEIPS.pdf

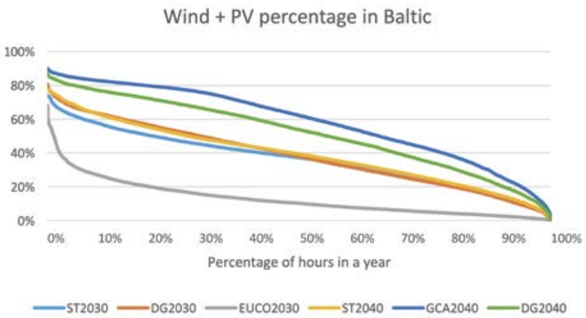
[9] An example of related investigations is the MIGRATE project - Massive InteGRATion of power Electronic devices. https://www.h2020-migrate.eu/

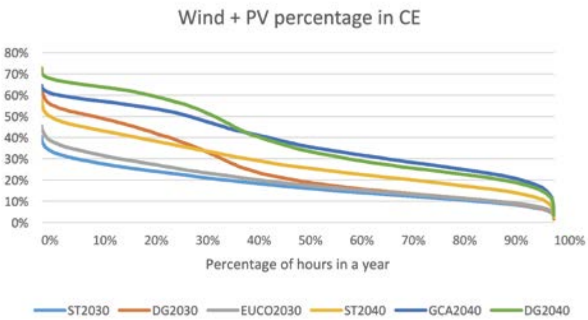
1.3.3 Flexibility needs

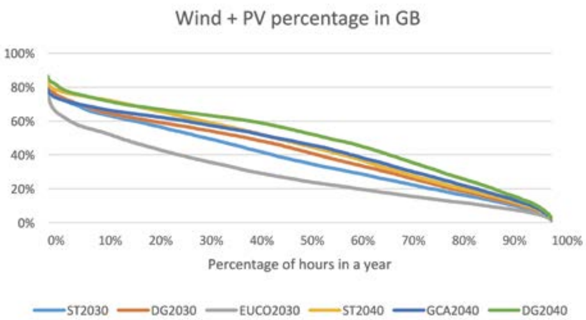
Unlike conventional generation with costly but controllable sources of primary energy, RES utilise primary energy sources that are free but have a variable nature. Hence, the high installed capacity of RES and their close-to-zero marginal costs cause conventional generation, with primary energy sources independent of weather conditions, to be displaced from the market.

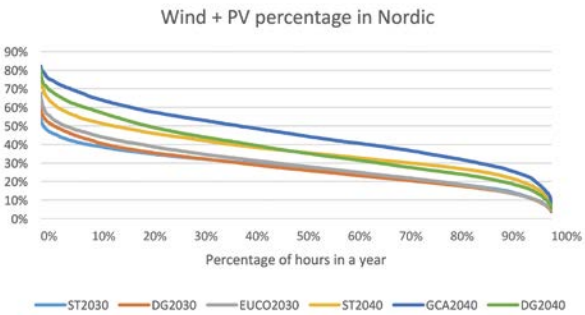
The plots in Figure 13 below depict the duration curves of the ratio between the sum of wind and solar photovoltaic generation (not considering all other RES) and total generation. This conservative ratio gives an image of the percentage of variable RES generation over the total generation for all synchronous areas and TYNDP scenarios in a full year.

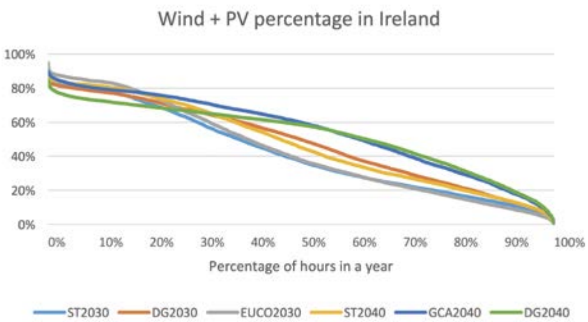
Figure 13: Duration curves of synchronous areas percentage of Wind+PV generation











Ratio of PV+Wind over total generation

High ratios of variable RES generation over the total generation are reached in all synchronous areas for some hours of the year – above 80% in all synchronous areas for some scenarios, except for CE (highest scenario close to 70%).

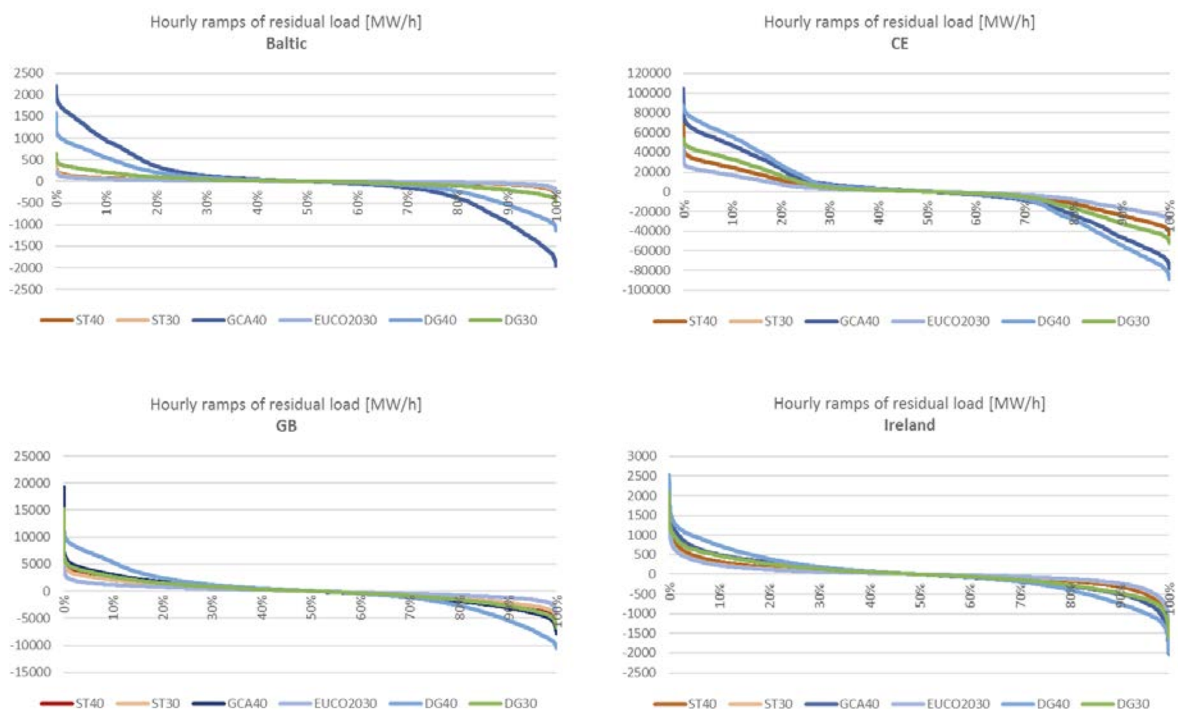
Reduced amount of controllable units lead to high flexibility needs in normal operation.

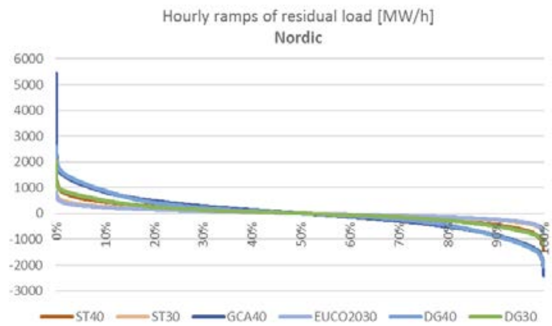
The variability in the power output from RES, which is driven by the variability of the primary energy resource, must be balanced, including forecast output deviations, in order to maintain the frequency equilibrium.

Residual load ramps exhibit the changes of residual load (demand minus RES) from one hour to the following hour. These curves express the response (in MW/hour) that needs to be provided by controllable generating units in order to maintain balance between generation and demand. They also provide an additional measure into the challenges of operating a system with reduced amount of controllable units, high flexibility needs in normal operation, and a requirement to guarantee the necessary volume of frequency reserves in all timescales for the cases of unforeseen imbalances between active power generation and demand.

The plots in Figure 14 display the duration curves of residual load ramps as the changes of residual load (load minus RES) from one hour to the following one in a synchronous area on a full year. RES includes all RES sources except hydro.

Figure 14: Duration curves of synchronous areas residual load ramps





Residual load ramps

High response (in MW/hour) that needs to be provided by controllable generating units in order to maintain balance between generation and demand is verified in all synchronous areas.

Need to guarantee the necessary volume of frequency reserves in all timescales for the cases of unforeseen generation and demand imbalances.

Flexibility sources will be necessary both from the generation and demand side.

Strong interconnection between countries will be essential to exchange the power flows from flexibility sources.

In order to cope with this situation new flexibility sources will be necessary both from the generation and demand side. This includes new roles for thermal plants, RES participation, demand side response, and storage. Also from the network side, strong interconnection between countries will be essential to exchange the power flows from flexibility sources.

Investments to allow large power flows covering vast distances and flexibility rewards to providers will be central aspects to the solution.

1.3.4 Transient and voltage stability related aspects

The power flow constraints, in highly meshed areas with an "optimal" distribution of generation units around the consumption areas, are generally based on static limits such as thermal overloads or steady state voltages exceeding operational limits. Various forms of stability issues are seen due to; the increase of volumes and distance of cross-border exchanges, the increase of the static limits of the grid elements, and the penetration of power electronic driven and controlled generation and demand.

In order to have a global view on transient and voltage stability challenges and coordination needs, a perspective built from information provided by the TSOs within the TYNDP planning process is here described.

Local transient stability (Rotor Angle stability)

Short-circuit power has been commonly used as an indicator of the system strength and, consequently, the ability of a synchronous generating unit to ride through a large disturbance and remain in synchronism with the system. A strongly meshed system with enough synchronous generation running at all times will have a high short-circuit level.

As converter-connected RES replaces synchronous generation, and as the power generated has to be transmitted over a long distance due to generation being further away from demand centres, the short-circuit power will tend to drop to very low levels. This reduction in short-circuit power will result in deeper and more widespread voltage dips in case of network faults. This will have a significant negative impact on the transient stability of generating units. It will also result in an increase in the number of generating units affected by the fault.

Box 2: TSOs perspective – Voltage dips resulting from a short circuit are increasing in magnitude and duration and are more widespread:

— Due to reduced number of synchronous machines, relatively big amount of RES and DC interconnection with neighbouring TSOs, the voltage dips during short circuits are deeper and could affect a larger region, thus more distributed RES are affected by a voltage dip and the risk of disconnection of a large number of RES increases.

— Even if currently there are no immediate problems, there is a verified decrease in the minimum short-circuit levels. With the increase of penetration of RES connected to the grid by power electronics, a larger reduction in the short circuit levels is expected.

— Local rotor angle stability of rotating machines (machine against the grid at the connection point) will change. There will be fewer rotating machines in future and the issue may be even more critical for the remaining ones.

Voltage control and management

The fluctuations in reactive power demand and reactive losses are increasing. This is driven by the higher reactive power losses associated with larger power transits, the reduced reactive demand due to the changing nature of the demand, and the increased reactive gain from lightly loaded circuits during low demand periods or during times of high output of embedded generation.

The large fluctuations in reactive power demand and reactive losses and the reduction in short-circuit power generally result in an increase in both voltage step changes and post-fault voltage excursions.
As reactive power reserves available on the transmission system are diminishing because transmission-connected synchronous generation is being displaced by embedded RES with power electronic interfaces, it is necessary to ensure that sufficient alternative measures are made available in order to ensure that voltage excursions can be managed within permissible limits.

Box 3: TSOs perspective on main challenges on voltage control and management.

— Generation relocation. Less natural distribution of dynamic reactive power reserve in the system.
— The potential need of developing and coordinating additional voltage sources directly connected to the transmission system, in such a way that the increased power transit will not be penalised.
— High transits at constant grid impedance due to dynamic rating or high temperature conductors. High current operation of overhead lines leads to a square rise of the reactive power demand (Q ~ I^2).
— Increase of reactive power losses with increasing distance between generation and load (Q ~ I).
— Distributed generation in lower voltage grids significantly replaces in some zones and scenarios the central units directly connected to EHV-grid. The PQ-characteristic of distribution systems changes depending on the Q-control strategy of the dispersed generation. Consequently, the reactive power flow pattern exchanged with the transmission system changes.
— Voltage sources may become more important at distribution level which could imply a stronger coordination between transmission and distribution operators, using distributed resources on top of the traditional scheme of distribution voltage controlled by On Load Tap Changers.
— The increase of exchanges in and variability lead to fast voltage variations. Investment in fast voltage control means might be necessary.
— In extreme low load cases, the system becomes more capacitive, which leads to overvoltage problems.
— Evolution of the exceptional contingencies, e.g. multiple faults due to transient angle instability or voltage instability, could lead to cascading line tripping (risk of system split).
— Reduction of the steady state voltage stability margin or voltage restoration ability.
— The interdependency in voltage and short-circuit current support among areas/TSOs is increased.
— The AC/DC converters may improve the transient stability. But the converters can also lose the stability in case of low short circuit power when they are under “grid following” control.

Solution and mitigation needs

The measures envisaged by TSOs to face the challenges are:

— Implementation of the connection codes: Requirements will be important as part of the solution measures by providing to relevant generation at all voltage levels with capabilities such as fault ride through and voltage support means.
— Investments on the network side: synchronous condensers, SVCs, STATCOM, HVDC, series compensation etc. to maintain stability should keep up with the investment in converter-based generation to avoid curtailment of this type of generation.
— Development of new type of Mvar ancillary services using aggregated sources and coordination with DSOs.
— Observability and controllability of distributed resources by the TSOs and DSOs as well as strong coordination between both operators.limits.

1.3.5 Additional network challenges

A number of challenges have been identified as new questions that are emerging and will require further analysis. This new type of phenomena, usually not monitored in system design and operation, will need to be monitored and studied in order to fully assess the system impact and solutions when necessary.

Extensive use of EHV-cables (for AC)	Extensive use of EHV-cables in the bulk power system, e.g. through overhead line replacements, introduces additional power quality, voltage control and reliability issues that must be managed to ensure safe and reliable network operation. There is thus a practical limitation to the cable distances that can be installed in EHV-networks to avoid hazardous resonance frequencies and large voltage control installations among others.
Interactions between new devices and controls	The dynamic behaviour of the power systems will change due to large-scale integration of AC/DC converters (in generation, storage, transmission or distribution grids) and the development of smart grids in distribution systems. This change is due to the fact that the dynamic behaviour of converters and of smart grids is specified by the control logic implemented in their control systems and in their protections systems. I.e., there is no fixed set of predictable and commonly known rules and/or laws of physics that would apply over the whole operating range and during disturbances. This control logic is generally protected by intellectual property and patents rights and, hence, it is usually not included in the power systems models used by TSOs. Another challenge associated with the change of the nature of the controls is the interactions between the new devices (control loop interactions, interactions due to non-linear functions, high frequency interactions i.e. harmonics and resonances…) or between these devices and the traditional AC grid and components (sub synchronous oscillations, harmonics…). These interactions may lead to power oscillations or can trigger device protections and may affect the reliability of the power system due to the increased probability of inadvertent tripping of equipment when the system is stressed. This would also mean increasing complexity of system operation for those conducting real-time system operations. The challenge for the TSOs will be the identification and mitigation of adverse interactions: — In order to identify the potential adverse interactions, TSOs need to collect sufficient information from manufacturers (HVDC, wind farms …), distribution system operators or service providers (smart grids) in order to perform the dynamic studies required to assess the impact on the whole system. However, as this information is protected by intellectual property rights, manufacturers would be reluctant to share such information. This would limit TSOs' ability to identify the risks. A good practice to reduce this risk is by testing the performance of equipment prior to its commissioning and using the test results to validate dynamic models. However, this might not be sufficient, as tests are not likely to include all potential operating conditions. — The challenge of mitigation: once identified, the interaction issues may require changes to the control systems. This includes the specification of the change required to a control logic that is owned by the manufacturer and the establishment of which party carries the liability in case of malfunction.
Cyber-physical systems	Power systems are becoming increasingly dependent on Information and Communication Technologies (ICT) up to the point where the physical system and the IT layer will merge into a cyber-physical system where real-time computing and physical systems interact tightly.
Inter-area oscillations	In addition to the function of transferring power, the transmission network binds remote generators' rotors together. The more meshed the network is, the stiffer the link will be. After a disturbance (a loss of generation for instance) distant groups of rotors oscillate against each other. These inter-area oscillations are generally well damped and generators stop oscillating after a few seconds. However, under adverse conditions the oscillations can be sustained and lead to significant power flow oscillations in the transmission lines (hundreds of MW) and to physical damage to generating units. This phenomenon is exacerbated by the weakness of the system (long distances or weakly meshed) and high power flows. In order to damp these oscillations, voltage and/or power controls of synchronous machines (Power System Stabiliser), FACTS or HVDC (Power Oscillation Dampers) have to be tuned appropriately. The increase of long distance power flows across Europe could require in some occasions coordinated tuning of the relevant control systems. Otherwise, inter-area oscillations may become a real concern which could notably undermine the profitability of interconnections if power transfer over such interconnections has to be restricted. The tuning of the controllers needs to be based on the results of a small signal stability analysis of inter-area oscillations in a synchronous area. This requires a significant amount of work and an accurate and validated dynamic model that represents all relevant devices participating in the oscillations.
Increasing amount of PSTs and internal SA HVDCs	HVDCs embedded within a Sychronous Area (SA) and Phase Shifting Transformers (PST) are able to control the active power flow on AC transmission lines and thus, overcome the natural physical load flow distribution according to the branch impedances. Depending on the induced additional voltage (vertical to the grid voltage) PST can achieve an evenly contribution of the power flow transmission lines according to their thermal capacity. As the network impedance is not reduced by PST or HVDC, the physical transmission capacity of the System remains constant. Thus, PST and HVDCs can be seen as tool to overcome local overloading due to a smooth power flow distribution but without increasing the maximum transmissible power of the system which is an image of the angular and voltage stability limits of the system. The number of PST and HVDCs in the European transmission system increases quickly. If local automatic tap changer/set-point controllers are applied, an additional level of coordinated control scheme must be developed, to avoid system security threats due to massive and uncoordinated shift of power flows after a disturbance which may worsen the overall system security situation.

1.3.6 Summary – The system needs

This chapter provides a comprehensive and factual perspective on many dynamic and operational challenges by providing the technical background, an explanation of their impact on the system and focusing on the relevant solutions or mitigation measures. The analysis is largely based on the presented indicators, computed for all the hours of the long-term TYNPD years and scenarios, which can be used to deliver measurable information on the trends regarding the system performance and challenges. This approach provides an objective basis to derive the necessary measures to tackle the challenges in a timely manner.

This chapter states the continued commitment of TYNDP 2018 to improve the analysis of the system, to measure the future dynamic and operability challenges and to factor them into the coordinated efforts of TSOs. By sharing this analysis the TYNDP also fosters better communication and cooperation with DSOs and all system users.

System design challenges are growing:

- Besides network investment solutions, the implementation of the Connection Network Codes to ensure the necessary technical requirements to grid users and the implementation of Europe's electricity market to ensure aspects such as reward to system flexibility and incentives for market participants to act in line with system needs remain key priorities.
- New type of phenomena have been identified in Section 5 that will need to be monitored and studied.
- Research & Investigation will be essential to meet the challenges. This requires coordination with research centres, manufacturers and stakeholders.

Operability challenges are growing.

- The future level of congestions: therefore possible needs for redispatch are important for operational planning, because resources for redispatch might not be always available. However, because of the uncertainty of the future bidding zone configurations, it is difficult to conduct a proper analysis on this.
- The evolution of the Network Codes, including the future version as depicted in the Clean Energy for All Europeans package (CEP) will have a big influence on the system operation regimes and impose important implications on network planning. For example new requirements on reserves will also evolve which include different rules for prequalification and dimensioning.
- New operational issues could arise – from the now-common N-1 criterion, voltage, frequency and other phenomena will have to be monitored in real-time (and operational planning). That includes ensuring safe levels of inertia in the whole system and sufficient short-circuit power in each point of the system (locally).

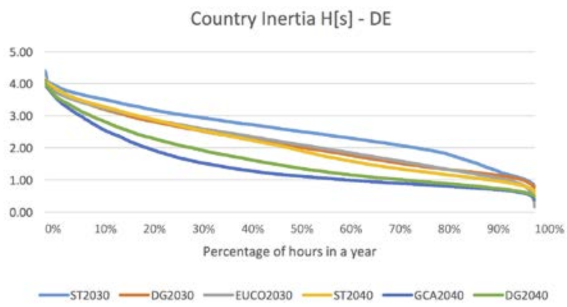
1.3.7 Additional background information
Part I – Estimated inertia in all countries

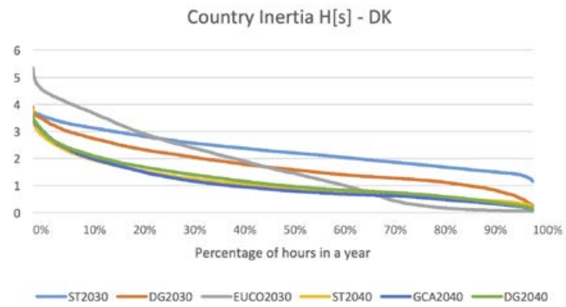
The plots in Figure 15 represent the estimated duration curve of inertia for each country in the ENTSO-E area. The plots are based on the market study results for all visions of the TYNDP 2018. Equivalent inertia for each country, presented as H[s], is calculated on the basis of total online capacity of the respective country for each hour.

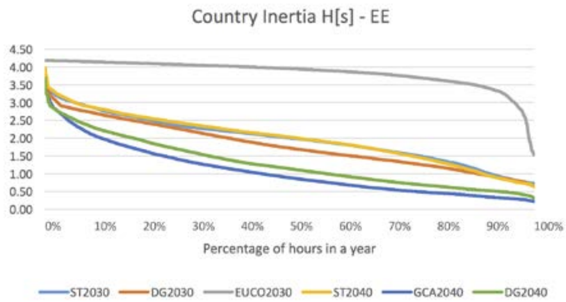
The estimation provides an image of the equivalent inertia resulting from the generation mix in each country for all the hours of the year. In general terms, countries presenting higher values of inertia have a generation mix with more share of synchronous generation (which may also include RES from hydro), conversely, countries presenting lower values of inertia have a generation mix with more share of converter connected RES.

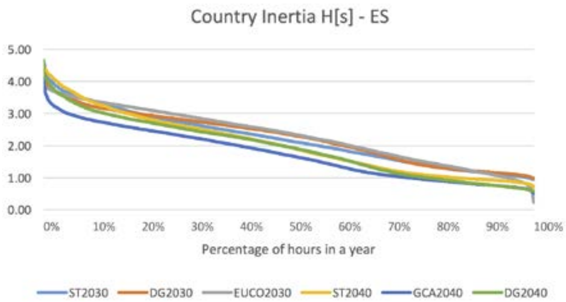
The following plots do not display an assumption of sufficient or insufficient inertia, or even of higher or lower RES integration. They only portray a supplementary insight into the level of the inherent diversity and internal variability of the different countries regarding equivalent inertia.

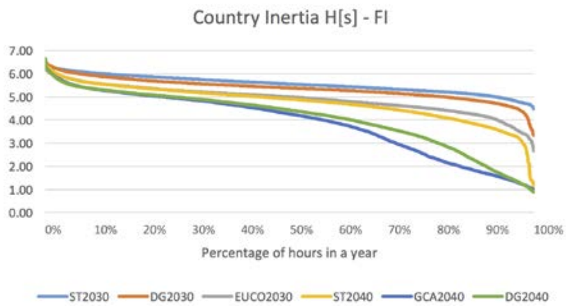
Figure 15: Duration curves of countries' estimated equivalent inertia (H(s))

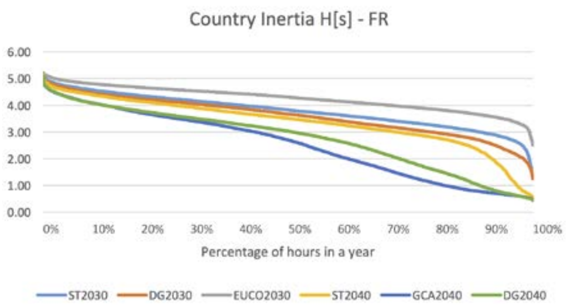

Country Inertia H[s] - DE
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

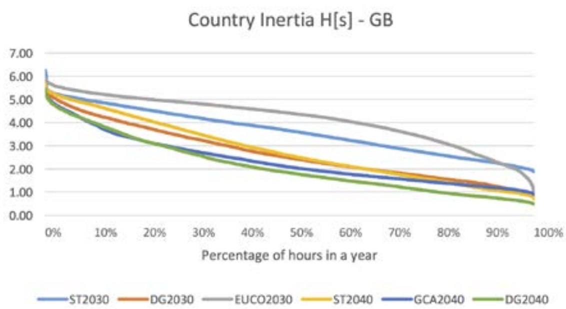

Country Inertia H[s] - DK
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

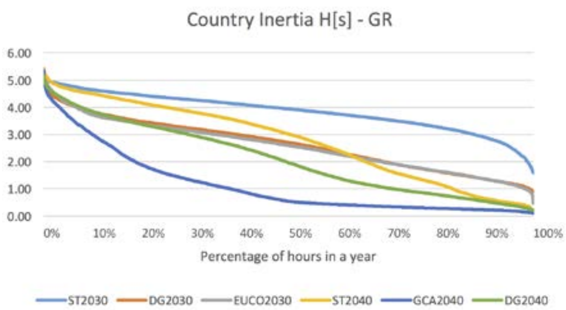

Country Inertia H[s] - EE
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

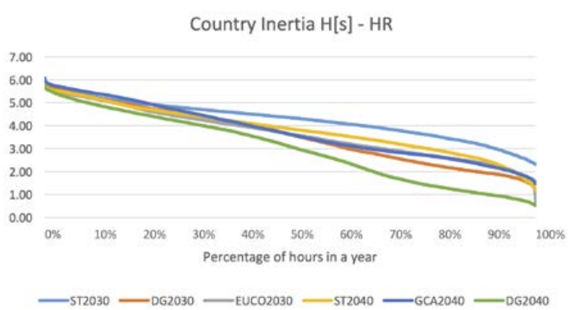

Country Inertia H[s] - ES
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

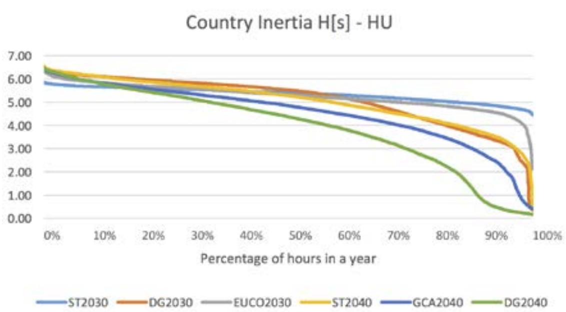

Country Inertia H[s] - FI
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

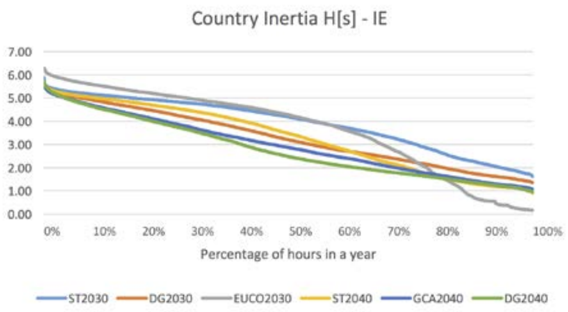

Country Inertia H[s] - FR
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

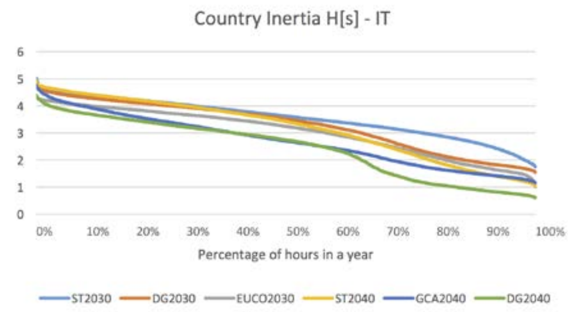

Country Inertia H[s] - GB
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

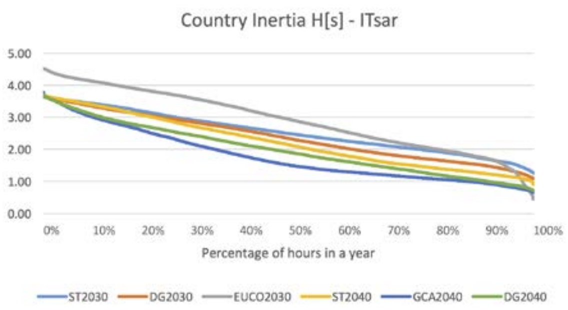

Country Inertia H[s] - GR
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

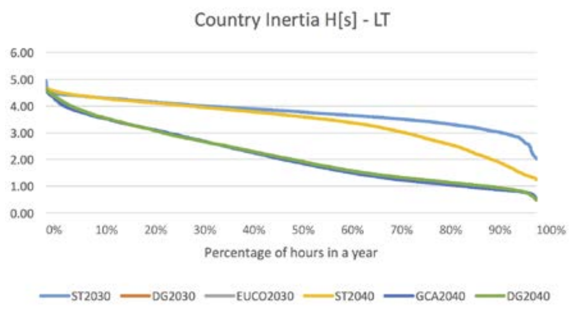

Country Inertia H[s] - HR
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

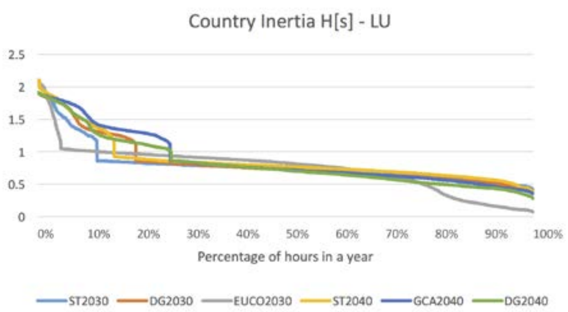

Country Inertia H[s] - HU
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

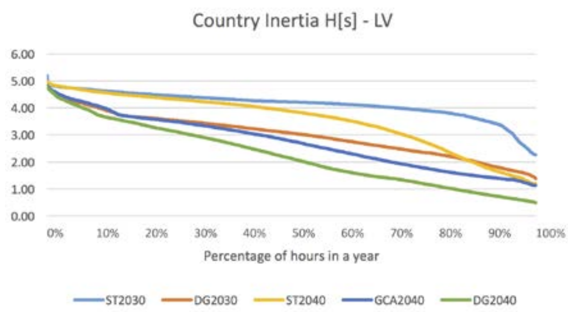

Country Inertia H[s] - IE
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

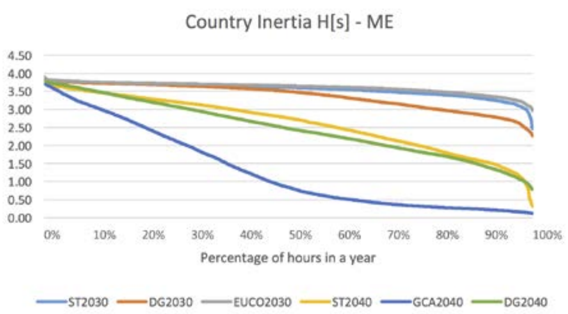

Country Inertia H[s] - IT
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

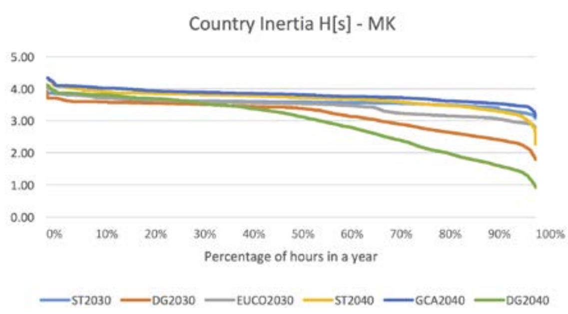

Country Inertia H[s] - ITsar
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

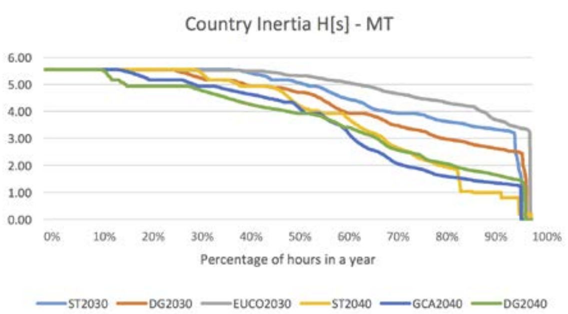

Country Inertia H[s] - LT
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

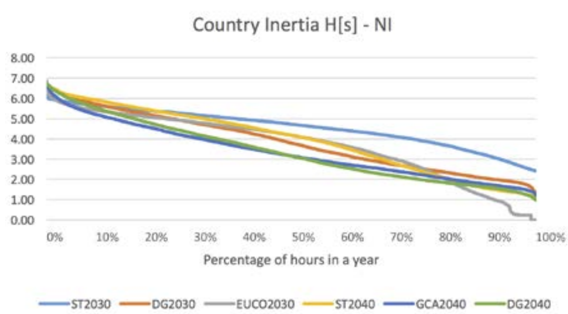

Country Inertia H[s] - LU
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

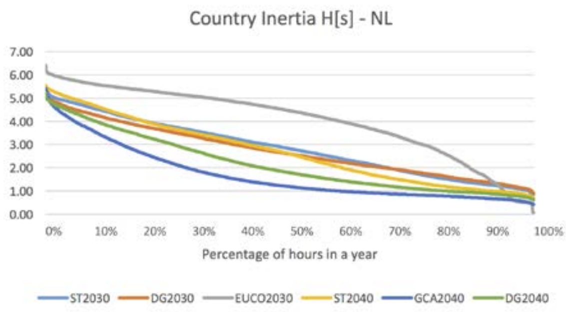

Country Inertia H[s] - LV
Percentage of hours in a year
ST2030 DG2030 ST2040 GCA2040 DG2040

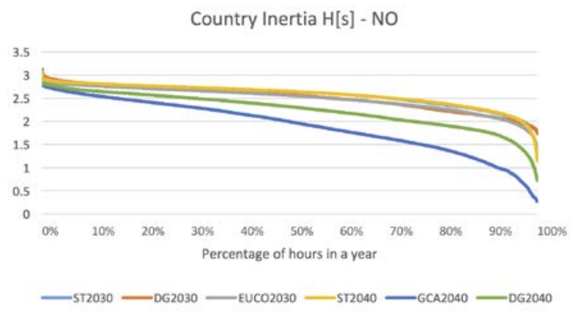

Country Inertia H[s] - ME
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

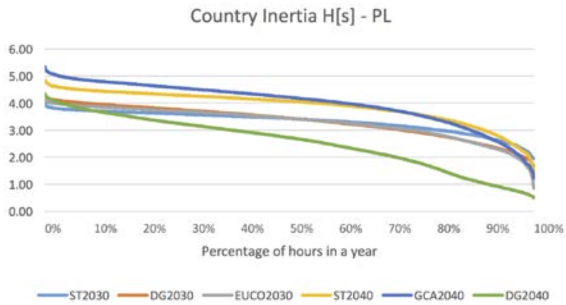

Country Inertia H[s] - MK
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

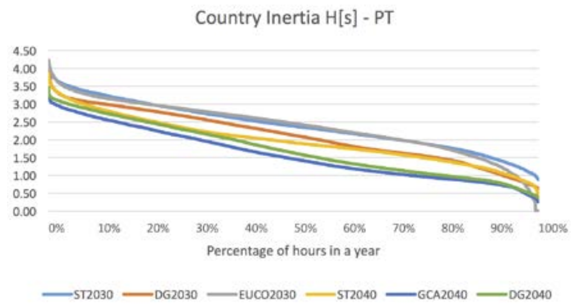

Country Inertia H[s] - MT
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

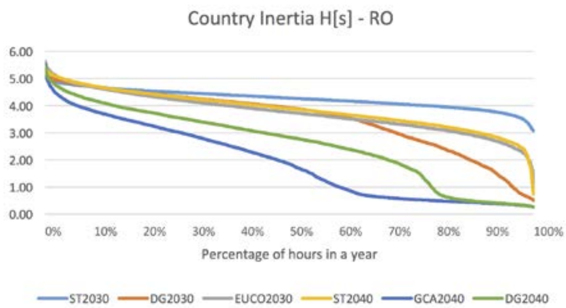

Country Inertia H[s] - NI
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

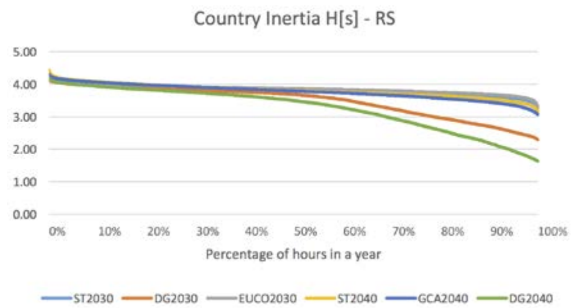

Country Inertia H[s] - NL
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

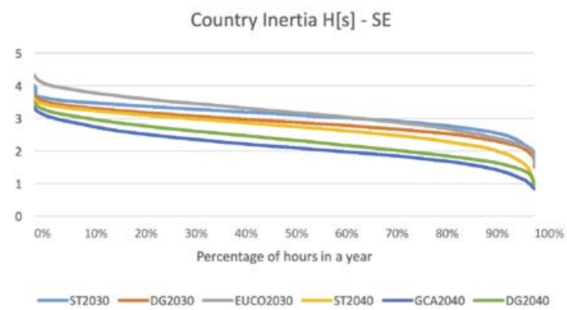

Country Inertia H[s] - NO
3.5
3
2.5
2
1.5
1
0.5
0
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

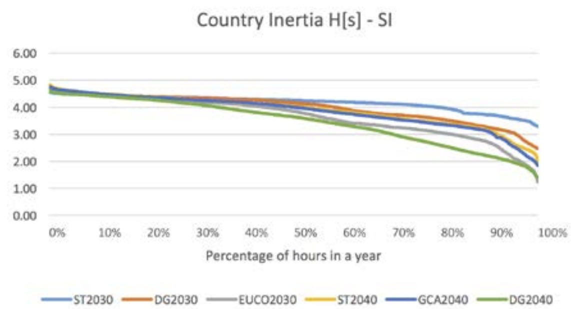

Country Inertia H[s] - PL
6.00
5.00
4.00
3.00
2.00
1.00
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

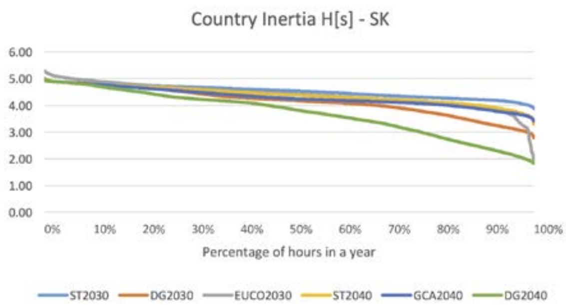

Country Inertia H[s] - PT
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

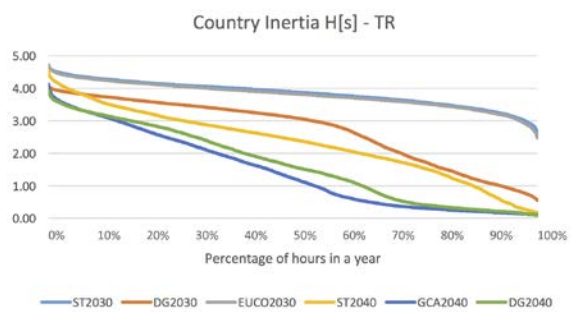

Country Inertia H[s] - RO
6.00
5.00
4.00
3.00
2.00
1.00
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040


Country Inertia H[s] - RS
5.00
4.00
3.00
2.00
1.00
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040


Country Inertia H[s] - SE
5
4
3
2
1
0
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040


Country Inertia H[s] - SI
6.00
5.00
4.00
3.00
2.00
1.00
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040


Country Inertia H[s] - SK
6.00
5.00
4.00
3.00
2.00
1.00
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040


Country Inertia H[s] - TR
5.00
4.00
3.00
2.00
1.00
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

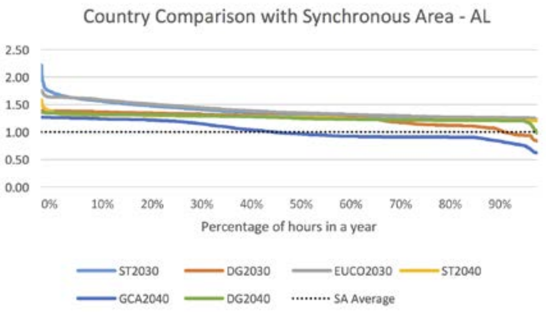
Part II – Country inertia comparison with synchronous area

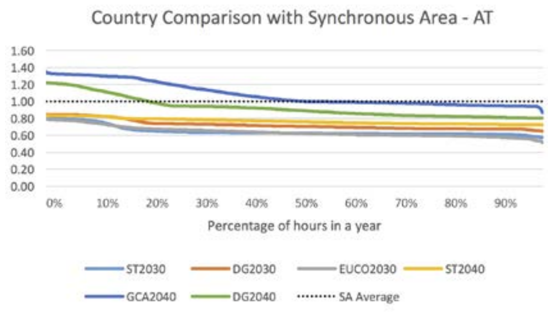
The plots in Figure 16 depict the duration curves of inertia for each country in the ENTSO-E area compared with the respective synchronous area average.

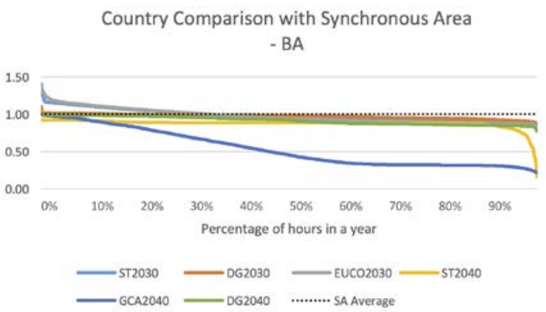
A value of 1 means that the inertia in a given hour is the same as the synchronous area average. Values below 1 do not show insufficient inertia, they only show that the country is below synchronous area average during that number of hours. Similarly, values above 1 show that the country is above synchronous area average during that number of hours.

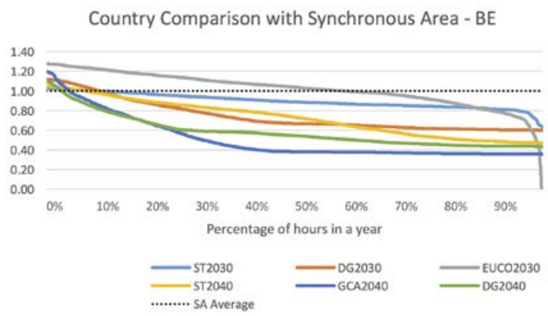
The following plots display the variability of each country regarding the comparison with the respective synchronous area average. Although a trend can be observed in the duration curves, depending on the hour, this comparison can vary significantly and can show values above or below 1.

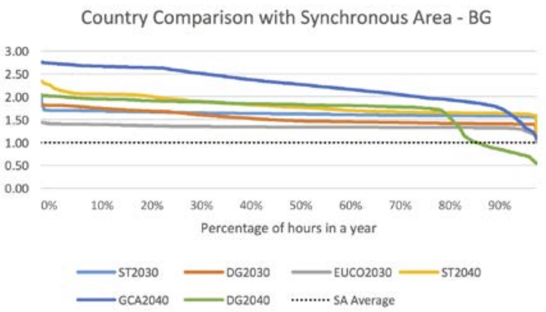
Figure 16: Duration curves of countries' inertia relative comparison with synchronous area

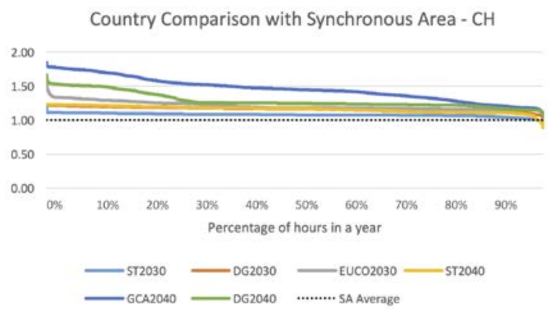


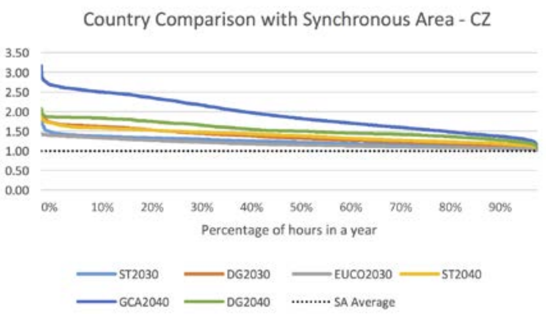


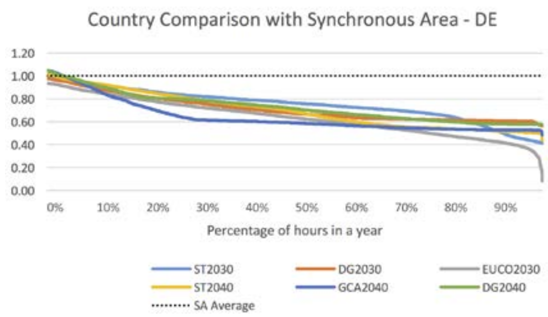


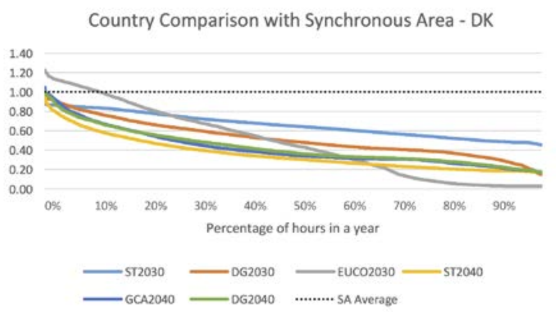


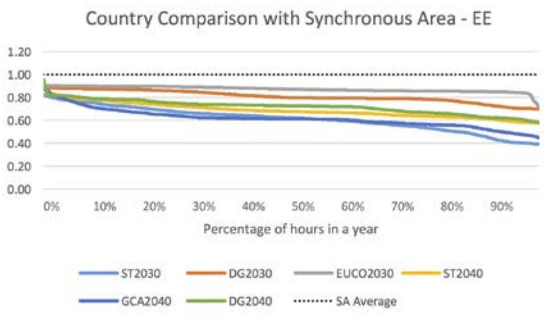


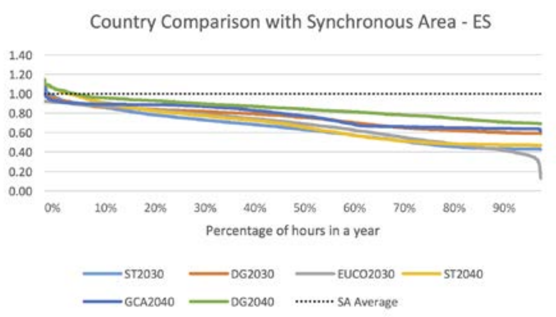


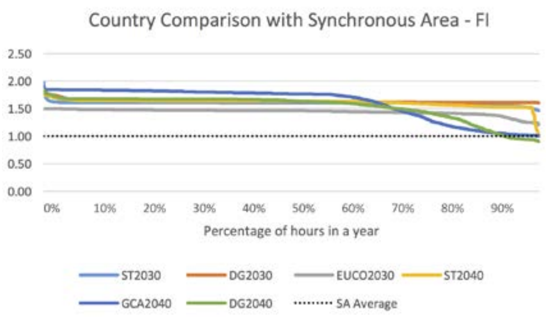


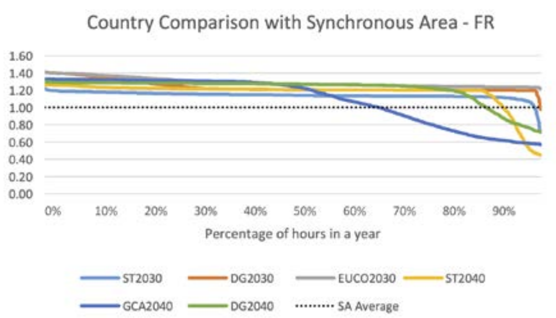


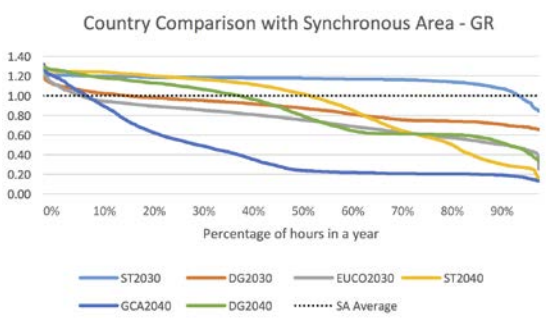

Country Comparison with Synchronous Area - DK
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

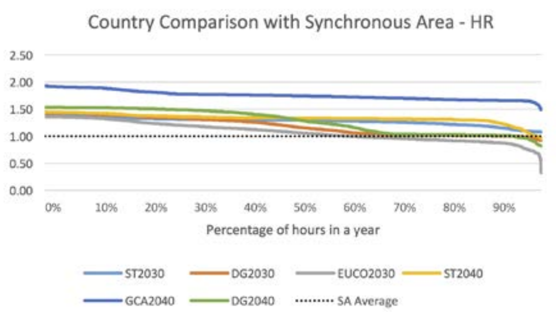

Country Comparison with Synchronous Area - EE
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

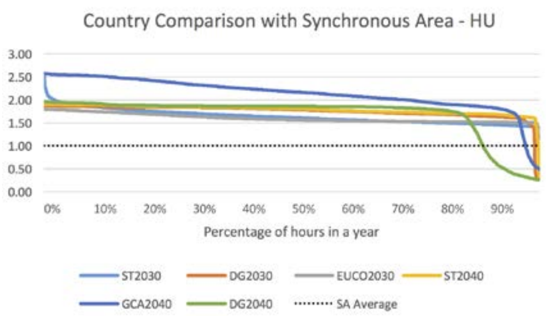

Country Comparison with Synchronous Area - ES
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

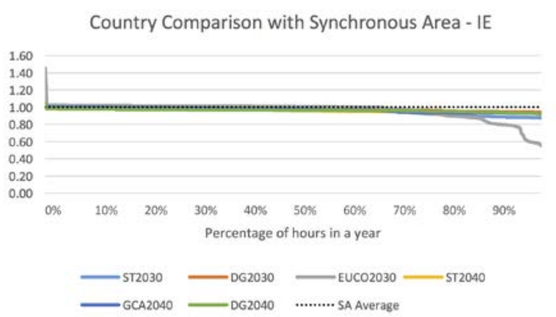

Country Comparison with Synchronous Area - FI
2.50
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

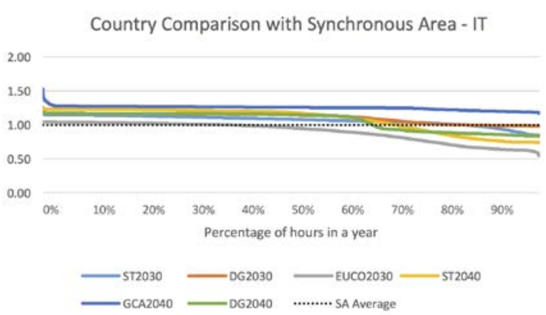

Country Comparison with Synchronous Area - FR
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

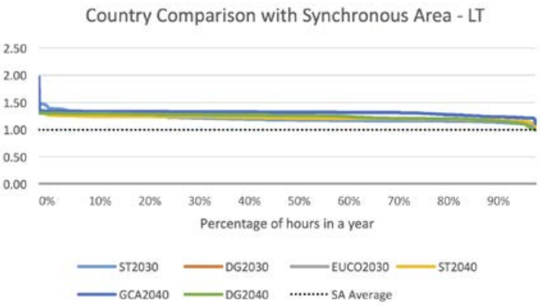

Country Comparison with Synchronous Area - GR
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

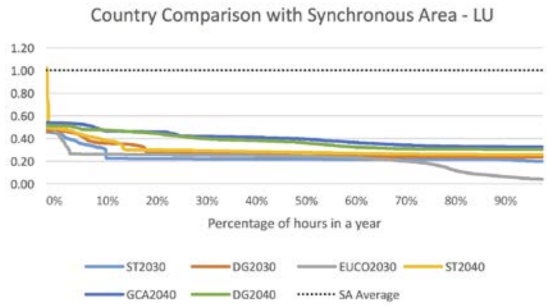

Country Comparison with Synchronous Area - HR
2.50
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

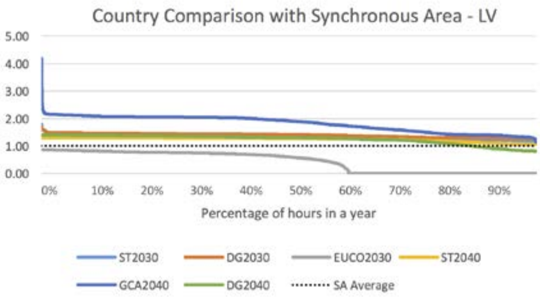

Country Comparison with Synchronous Area - HU
3.00
2.50
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

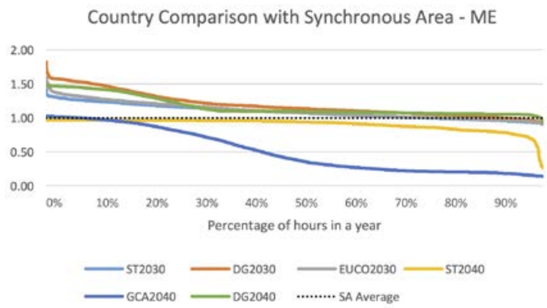

Country Comparison with Synchronous Area - IE
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

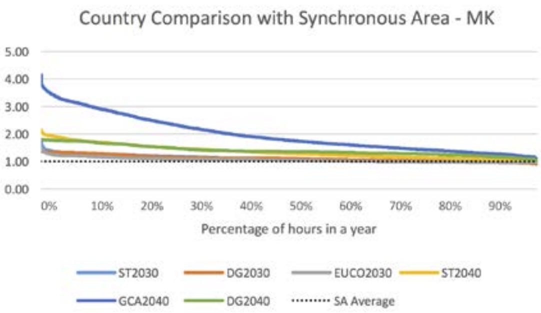

Country Comparison with Synchronous Area - IT
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

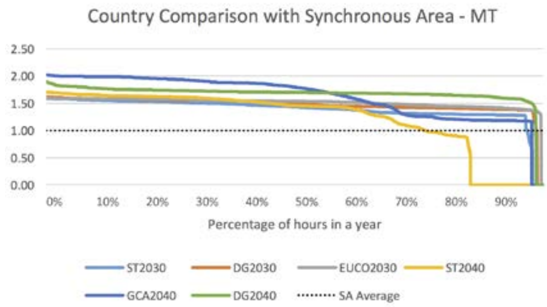

Country Comparison with Synchronous Area - LT
Percentage of hours in a year
ST2030
DG2030
EUCO2030
ST2040
GCA2040
DG2040
SA Average

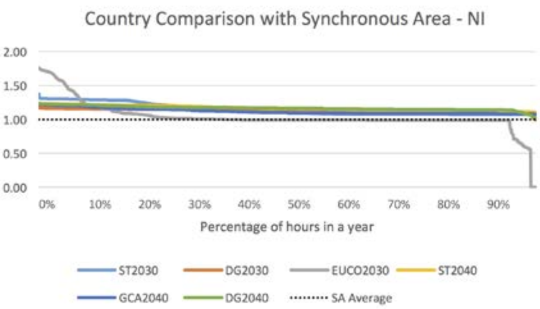

Country Comparison with Synchronous Area - LU
Percentage of hours in a year
ST2030
DG2030
EUCO2030
ST2040
GCA2040
DG2040
SA Average

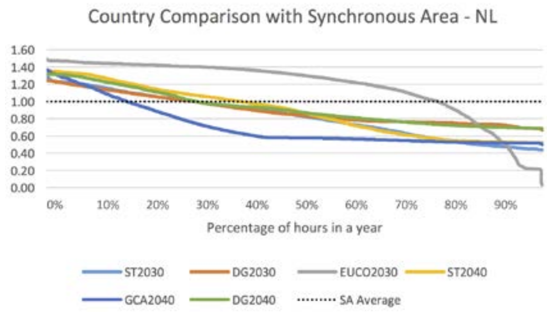

Country Comparison with Synchronous Area - LV
Percentage of hours in a year
ST2030
DG2030
EUCO2030
ST2040
GCA2040
DG2040
SA Average

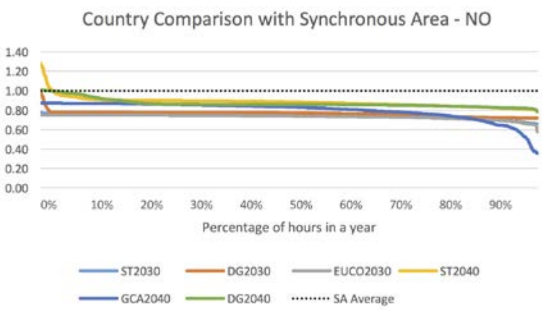

Country Comparison with Synchronous Area - ME
Percentage of hours in a year
ST2030
DG2030
EUCO2030
ST2040
GCA2040
DG2040
SA Average

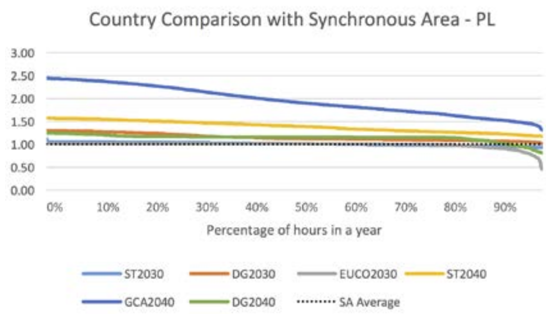

Country Comparison with Synchronous Area - MK
Percentage of hours in a year
ST2030
DG2030
EUCO2030
ST2040
GCA2040
DG2040
SA Average

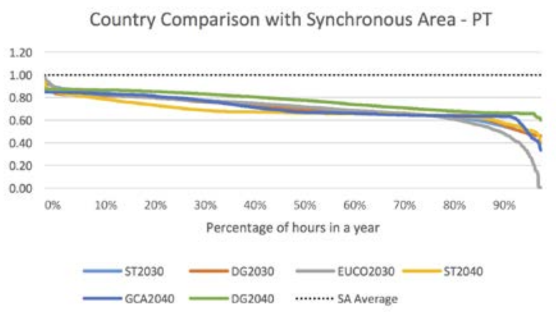

Country Comparison with Synchronous Area - MT
Percentage of hours in a year
ST2030
DG2030
EUCO2030
ST2040
GCA2040
DG2040
SA Average

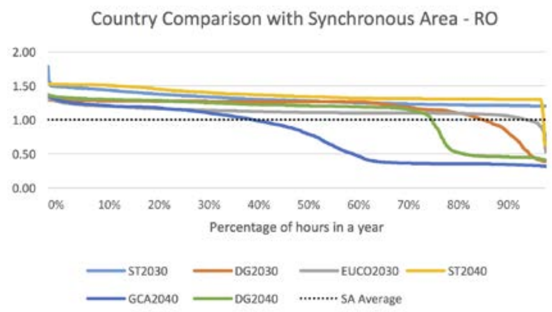

Country Comparison with Synchronous Area - NI
Percentage of hours in a year
ST2030
DG2030
EUCO2030
ST2040
GCA2040
DG2040
SA Average

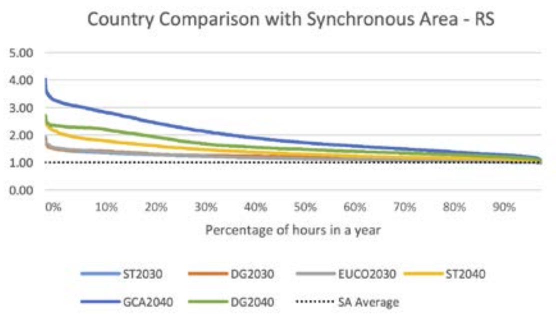

Country Comparison with Synchronous Area - NL
Percentage of hours in a year
ST2030
DG2030
EUCO2030
ST2040
GCA2040
DG2040
SA Average

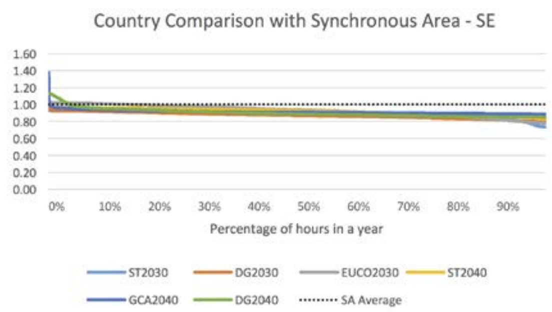

Country Comparison with Synchronous Area - NO
Percentage of hours in a year
ST2030
DG2030
EUCO2030
ST2040
GCA2040
DG2040
SA Average

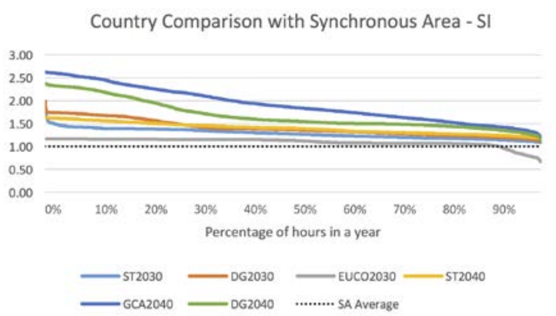

Country Comparison with Synchronous Area - PL
Percentage of hours in a year
ST2030
DG2030
EUCO2030
ST2040
GCA2040
DG2040
SA Average

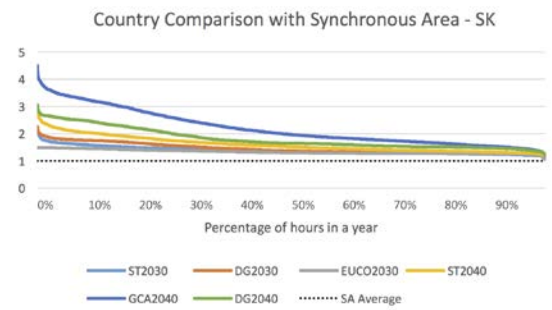

Country Comparison with Synchronous Area - PT
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

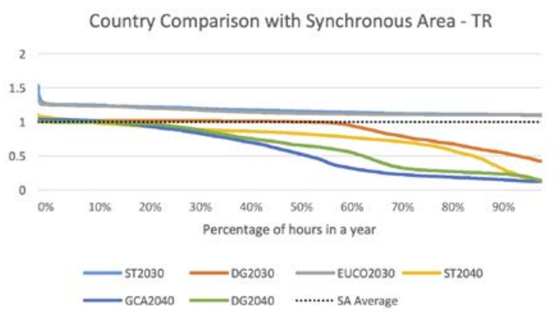

Country Comparison with Synchronous Area - RO
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average


Country Comparison with Synchronous Area - RS
5.00
4.00
3.00
2.00
1.00
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average


Country Comparison with Synchronous Area - SE
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average


Country Comparison with Synchronous Area - SI
3.00
2.50
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average


Country Comparison with Synchronous Area - SK
5
4
3
2
1
0
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average


Country Comparison with Synchronous Area - TR
2
1.5
1
0.5
0
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

ENTSO-E AISBL
Avenue de
Cortenbergh 100,
1000 Brussels,
Belgium

Tel (+32) 2 741 09 50

info@entsoe.eu
www.entsoe.eu

entsoe
Reliable Sustainable Connected