European Power System 2040

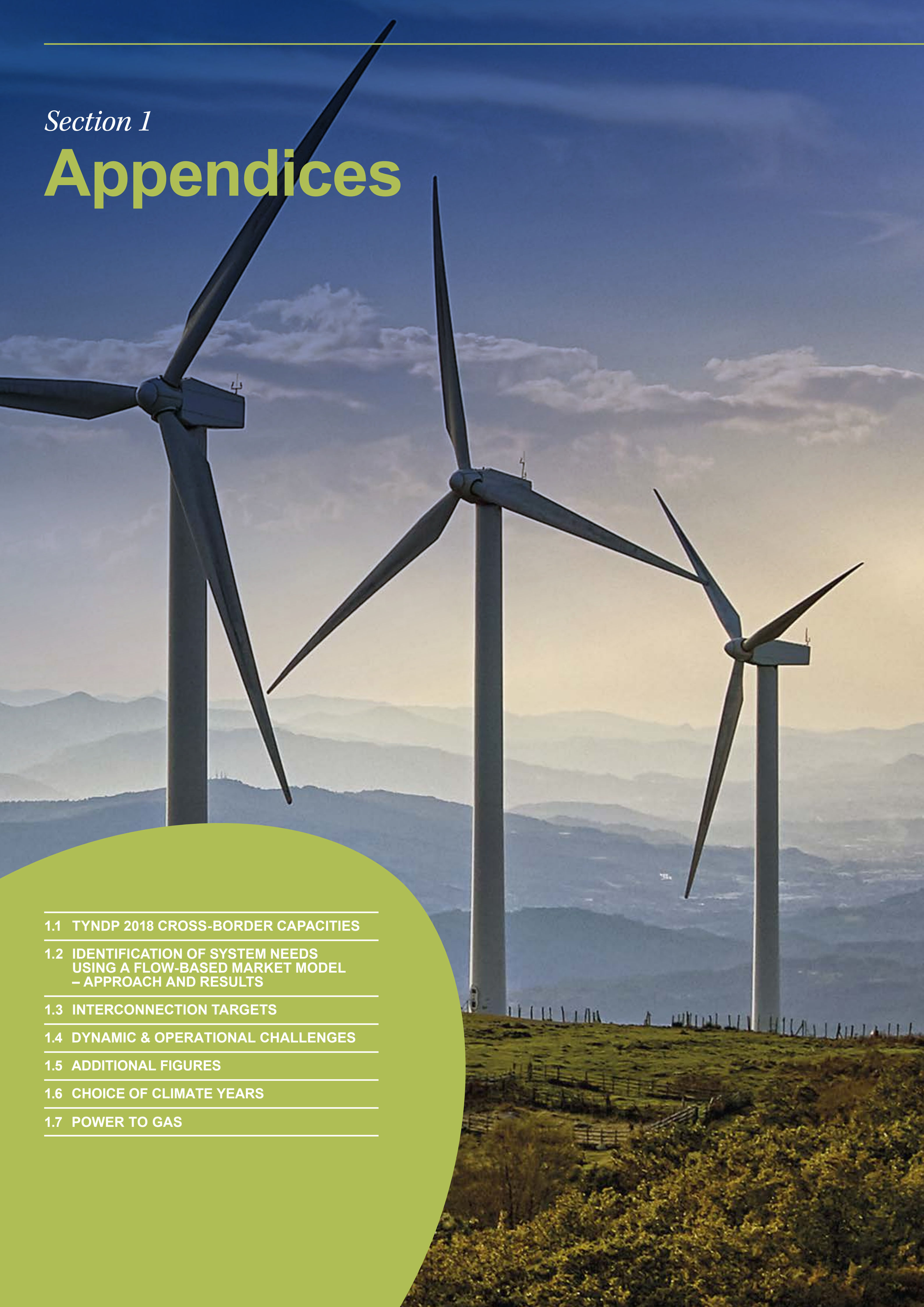
Completing the map

Technical Appendix

Final version after public consultation and ACER opinion - October 2019

entsoe

Reliable Sustainable Connected



Section 1

Appendices

1.1

TYNDP 2018 cross-border capacities

The table below summarises the needs for additional capacities in the three scenarios of 2040 as identified by ENTSO-E's Identification of System Needs process. The needs are compared to 2020 capacities as used by e.g. the ENTSO-E MAF studies. For some of these needs, there already exist specific projects which have been assessed in the previous TYNDP(s) and which will be assessed again during the following CBA-phase. Other needs might be assessed for the first time by new additional TYNDP 2018 projects. Finally there are needs identified for the 2040 time horizon, which are not yet materialised as project candidates to be assessed in 2025 and 2030 (the time horizons chosen for the CBA-phase). If these needs can be confirmed by future studies, they might become project candidates in later TYNDPs.

	NTC 2020		CBA Capacities		Scenario Capacities					
			NTC 2027 (Reference grid[1])		NTC ST2040		NTC DG2040		NTC GCA2040	
Border	=>	<=	=>	<=	=>	<=	=>	<=	=>	<=
AL-GR	250	250	250	250	350	350	350	350	350	350
AL-ME	350	350	400	400	900	900	400	400	400	400
AL-MK	500	500	500	500	500	500	500	500	1000	1000
AL-RS	650	500	500	500	1260	830	760	330	1760	1330
AT-CH	1200	1200	1700	1700	1700	1700	1700	1700	1700	1700
AT-CZ	900	800	1000	1200	1000	1200	1000	1200	1000	1200
AT-DE	5000	5000	7500	7500	7500	7500	7500	7500	7500	7500
AT-HU	800	800	1200	800	1200	800	1200	800	1200	800
AT-ITn	405	235	1050	850	1605	1335	1605	1335	1605	1335
AT-SI	950	950	1200	1200	2200	2200	2200	2200	2700	2700
BA-HR	750	700	1250	1250	1844	1812	1844	1812	2344	2312
BA-ME	500	400	800	750	500	400	500	400	500	400
BA-RS	600	600	1100	1200	1100	1200	1100	1200	1100	1200
BE-DE	1000	1000	1000	1000	1000	1000	2000	2000	2000	2000
BE-FR	1800	3300	2800	4300	4300	5800	3800	5300	4300	5800
BE-GB	1000	1000	1000	1000	2500	2500	2000	2000	2000	2000
BE-LUB	380	0	380	0	380	0	380	0	380	0
BE-LUG	300	180	300	180	300	180	300	180	800	680
BE-NL	2400	1400	3400	3400	4900	4900	4400	4400	4900	4900
BG-GR	600	400	1350	800	1728	1032	3228	2532	3228	2532
BG-MK	400	100	500	500	400	100	400	100	900	600
BG-RO	300	300	1100	1500	1400	1500	1400	1500	1400	1500
BG-RS	500	200	350	200	1600	1350	2100	1850	2100	1850
BG-TR	700	300	1200	500	2400	2000	2400	2000	2400	2000
CH-DE	4600	2700	5600	3300	6500	4100	6500	4100	6500	4100
CH-FR	1300	3150	1300	3700	2800	5200	3800	6200	3800	6200
CH-ITn	4240	1910	6000	3700	6000	3700	6000	3700	6000	3700
CY-GR	0	0	0	0	2000	2000	2000	2000	2000	2000
CZ-DE	2100	1500	2600	2000	2600	2000	2600	2000	2600	2000
CZ-PLE	0	800	0	600	0	800	0	800	0	800
CZ-PLI	600	0	600	0	600	0	600	0	600	0
CZ-SK	1800	1100	1800	1100	2100	1100	2100	1100	2600	1600
DE-DEkf	400	400	400	400	400	400	400	400	400	400
DE-DKe	600	585	600	585	600	600	600	600	600	600

[1] The "Reference grid" specifies the capacities which will be used as a starting point for the upcoming Cost-Benefit Analyses. These capacities will be updated in the final publication of this document after the consultation period.

	NTC 2020		CBA Capacities		Scenario Capacities					
			NTC 2027 (Reference grid[1])		NTC ST2040		NTC DG2040		NTC GCA2040	
Border	=>	<=	=>	<=	=>	<=	=>	<=	=>	<=
DE-DKw	1500	1780	3000	3000	3000	3000	3000	3000	3000	3000
DE-FR	2300	1800	4500	4500	4800	4800	5800	5800	4800	4800
DE-GB	0	0	1400	1400	1400	1400	1400	1400	1400	1400
DEkf-DKkf	400	400	400	400	400	400	400	400	400	400
DE-LUG	1000	1000	1000	1000	2000	2000	2000	2000	3000	3000
DE-LUv	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300
DE-NL	4250	4250	5000	5000	5000	5000	5000	5000	5000	5000
DE-NOs	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
DE-PLE	0	2500	0	3000	0	3000	0	3000	0	3000
DE-PLI	500	0	2000	0	4500	0	3500	0	4500	0
DE-SE4	615	615	1315	1300	1815	1815	2315	2315	2315	2315
DKe-DKkf	400	600	600	600	400	600	400	600	400	600
DKe-DKw	600	590	600	600	1100	1090	1100	1090	1100	1090
DKe-PL	0	0	0	0	500	500	1500	1500	500	500
DKe-SE4	1700	1300	1700	1300	1700	1300	2700	2300	2700	2300
DKw-GB	0	0	1400	1400	1400	1400	1400	1400	1400	1400
DKw-NL	700	700	700	700	700	700	700	700	700	700
DKw-NOs	1640	1640	1700	1640	2140	2140	1640	1640	2640	2640
DKw-SE3	740	680	740	680	740	680	740	680	740	680
EE-FI	1016	1000	1016	1016	1016	1000	1016	1000	1516	1500
EE-LV	900	900	1379	1379	1350	1250	1850	1750	1350	1250
ES-FR	2600	2800	5000	5000	9000	9000	10000	10000	9000	9000
ES-PT	4200	3500	4200	3500	4700	4000	4700	4000	5700	5000
FI-NOn	0	0	0	0	0	0	0	0	1000	1000
FI-SE1	1100	1200	2000	2000	2500	2500	2500	2500	2500	2500
FI-SE2	0	0	0	0	800	800	800	800	800	800
FI-SE3	1200	1200	1200	1200	800	800	800	800	800	800
FRc-ITCO	50	150	150	200	150	200	150	200	150	200
FR-GB	2000	2000	6800	6800	6900	6900	5900	5900	5900	5900
FR-IE	0	0	0	0	700	700	1200	1200	1200	1200
FR-ITn	4350	2160	4350	2160	4350	2160	4350	2160	5350	3160
FR-LUF	380	0	380	0	380	0	380	0	380	0
GB-IE	500	500	500	500	1500	1500	500	500	500	500
GB-NI	450	80	450	280	500	500	500	500	500	500
GB-NL	1000	1000	1000	1000	2500	2500	1000	1000	2000	2000
GB-NOs	0	0	2800	2800	1400	1400	2900	2900	2400	2400
GR-ITs	500	500	500	500	500	500	500	500	500	500
GR-MK	1100	850	1200	1200	1600	1350	2100	1850	2100	1850
GR-TR	660	580	660	580	2200	2100	2200	2100	2200	2100
HR-HU	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000
HR-RS	600	600	600	600	2100	2100	2100	2100	2100	2100
HR-SI	1500	1500	2000	2000	2500	2500	3000	3000	3500	3500
HU-RO	1000	1100	1300	1400	1300	1400	1800	1900	2800	2900
HU-RS	600	600	600	600	1100	1100	2100	2100	2100	2100
HU-SI	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
HU-SK	2000	2000	2000	2000	2000	2000	2000	2000	2000	2000
IE-NI	300	300	1250	1200	1100	1100	1100	1100	1100	1100
ITcn-ITCO	300	300	400	400	400	400	400	400	400	400
ITcn-ITCO	300	300	400	400	400	400	400	400	400	400
ITcn-ITcs	1400	2600	1750	3200	2750	4200	2750	4200	2750	4200
ITcn-ITn	1550	3750	2100	4100	2100	4100	2100	4100	2100	4100
ITcs-ITs	9999	4500	9999	5700	9999	5700	9999	5700	10999	6700
ITcs-ITsar	700	900	700	900	700	900	700	900	700	900
ITcs-ME	600	600	1200	1200	1200	1200	1200	1200	1200	1200
ITn-SI	680	730	1660	1895	1660	1895	1660	1895	1660	1895

	NTC 2020		CBA Capacities		Scenario Capacities					
			NTC 2027 (Reference grid[1])		NTC ST2040		NTC DG2040		NTC GCA2040	
Border	=>	<=	=>	<=	=>	<=	=>	<=	=>	<=
ITsar-ITCO	350	300	500	450	500	450	500	450	500	450
ITsic-ITsar	0	0	0	0	1000	1000	1000	1000	1000	1000
ITsic-MT	200	200	200	200	200	200	200	200	200	200
ITsic-TN	0	0	600	600	600	600	600	600	600	600
ITs-ITsic	1100	1200	1100	1200	2100	2200	2100	2200	2100	2200
LT-LV	1200	1500	1200	1500	1200	1500	1200	1500	1200	1500
LT-PL	500	500	1000	1000	500	500	1000	1000	1000	1000
LT-SE4	700	700	700	700	700	700	700	700	700	700
ME-RS	500	600	700	700	1000	1100	1000	1100	1500	1600
MK-RS	650	800	750	750	650	800	1650	1800	1650	1800
NL-NOs	700	700	700	700	1700	1700	1700	1700	1700	1700
NOm-NOn	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300
NOm-NOs	1400	1400	1400	1400	1400	1400	1400	1400	1900	1900
NOm-SE2	600	1000	600	1000	600	1000	600	1000	600	1000
NOn-SE1	700	600	700	600	700	600	700	600	700	600
NOn-SE2	250	300	250	300	250	300	250	300	750	800
NOs-SE3	2145	2095	2145	2095	2145	2095	2145	2095	2145	2095
PLE-SK	990	0	990	0	990	0	990	0	990	0
PLI-SK	0	990	0	990	0	990	0	990	0	990
PL-PLE	2500	0	3000	0	3000	0	3000	0	3000	0
PL-PLI	0	500	0	2000	0	4500	0	3500	0	4500
PL-SE4	600	600	600	600	600	600	600	600	1100	1100
RO-RS	1000	800	1300	1300	1450	1050	1950	1550	2950	2550
SE1-SE2	3300	3300	3300	3300	3300	3300	3300	3300	3300	3300
SE2-SE3	7800	7800	7800	7800	8300	8300	8300	8300	8300	8300
SE3-SE4	6500	3200	7200	3600	7200	3600	7200	3600	7200	3600

[1] The "Reference grid" specifies the capacities which will be used as a starting point for the upcoming Cost-Benefit Analyses. These capacities will be updated in the final publication of this document after the consultation period.

1.2

Identification of system needs using a flow-based market model approach

While the generation mix throughout Europe is changing very fast, the development of the European integrated market, together with the interconnection reinforcements, significantly enlarge the playing field to be tackled in long-term grid planning studies. This also poses new challenges to identify and assess network reinforcements in long-term studies such as the ones performed by European Transmission System Operators for the TYNDP. Therefore ENTSO-E did a new and innovative study in parallel with the classical approach for the assessment of system needs for the 2040 scenarios. This additional study was based on a flow-based approach, similar to the one used within the E-Highway 2050 project. ENTSO-E will consider the approach and results of this study further and it will be investigated, whether it is appropriate and how this can be implemented in future TYNDPs.

1.2.1 Conventional methods for grid planning: a two-step approach

The conventional methods used by ENTSO-E teams to assess power flows, congestions and needed reinforcements on the grid are based on a two-step approach made up of a "market" study, followed by a detailed network study.

Market Studies consist currently in market simulations of a single representative node at country[2] level of the European system, interconnected with market Net Transfer Capacities (NTC). Calculations to determine market and system outputs are made for each hour of the year and for different climatic conditions and time horizons.

Results of market studies are then transposed from national single node into a more detailed network (down to the substation level), to enable Network Studies. These are realised through two complementary approaches:

- Deterministic approach, which aims to detect voltage constraints and overloads, through an analysis of a reduced number of load/generation configurations (so-called "snapshots").
- Probabilistic approach, which aims to assess benefits provided by an interconnection reinforcement (mainly increase of NTC on one or several boundaries and losses). Those benefits are estimated based on a high number of plausible load/generation configurations at nodal level, derived from a reference situation (seasonal base-case).

1.2.2 A new methodology at an experimental stage

ENTSO-E experiments with a new method for the assessment of system needs in 2040 scenarios, based on a flow-based approach, similar to the one used within the E-Highway 2050 project.

Indeed, the scenarios in "European Power System 2040: Completing the map" report aim to detect the major electric energy transportation issues and the most valuable cross-border reinforcements. It does not intend to design precisely each reinforcement and define the optimal portfolio of new projects, which would be unrealistic for such a horizon.

Therefore, given the time horizon, the size of the geographic scope and the granularity of the expected results of such a study, a flow-based market model seems to be particularly appropriate and efficient as:

- it includes network model constraints directly in the market model
- it removes the need to allocate the generation from country level to nodal level
- it enables a balanced description of the network that goes beyond the interconnectors, without modelling the whole grid (all voltage levels and substations), while procuring a good estimate of actual flows along the transmission corridors of the European grid; more refinements in the spatial description seems illusive
- the computation time is acceptable.

[2] Except for the countries currently divided into several bidding zones such as Italy, Denmark Sweden and Norway.

1.2.3 Main principles of a flow-based market model

The tested method relies on the integration of a simplified model of the physical grid directly into the market model. The "physical" equivalent impedances of the different links are calculated and used by the model to constrain the flows to comply with Kirchhoff's mesh rule.

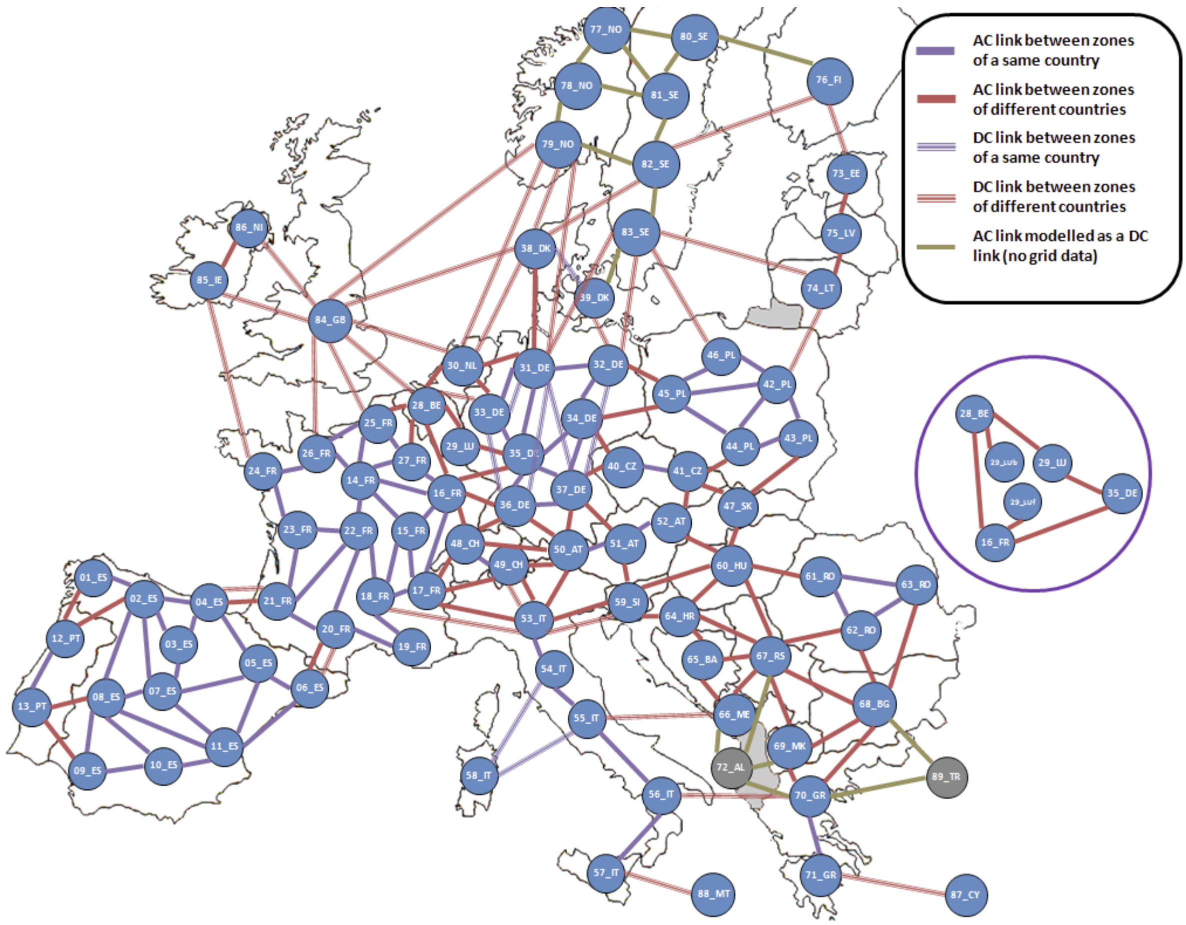
Key drivers of the methodology:

1. The physical model included in the simplified grid removes some of the limits related to commercial exchange capacities and better assess physical flows, on both internal grid and interconnections, in a coherent way.
2. The simplification of the grid allows tackling a large scope of plausible futures, and measuring the impact of various energy mixes on macroscopic corridors of the network; a macro analysis of major overloads and bottlenecks can be conducted for several scenarios.
3. The approach creates an intermediary level between "Market studies", performed at country/ bidding zone level, and "Network Studies", carried out at a nodal level, making the downscaling and the link between different processes easier.

To reach a sufficient level of accuracy in the reduced grid, large countries have to be modelled as smaller zones. Generation and consumption hypothesis have then to be built at this new zonal level, which allows accounting for the location of the different types of generators within large countries (wind in the north and solar in the south have not the same impact on the grid, for instance).

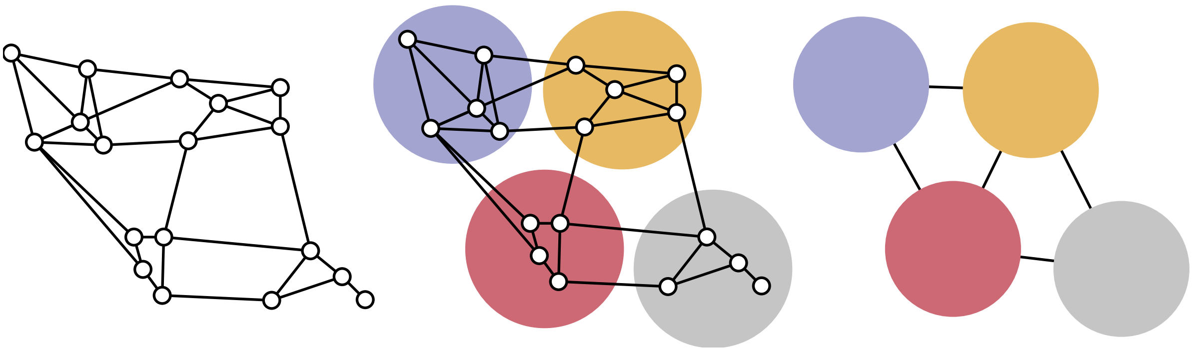
For the first experiment described in this Appendix, the definition of zones was based on the one elaborated during the E-Highway 2050 project. It is characterised by a high degree of consultation of results and inclusion of feedback by TSOs and ENTSO-E. The definition of zones is depicted in Figure 1.

Figure 1: Zones used for the experiment and based on E-Highway 2050



The process leads to a simplified network illustrated in Figure 2, where all substations of a given area are merged in an equivalent node – a “zone” – and all links between two areas are unified in an equivalent link – an “inter-zone”.

Figure 2: From detailed to reduced network



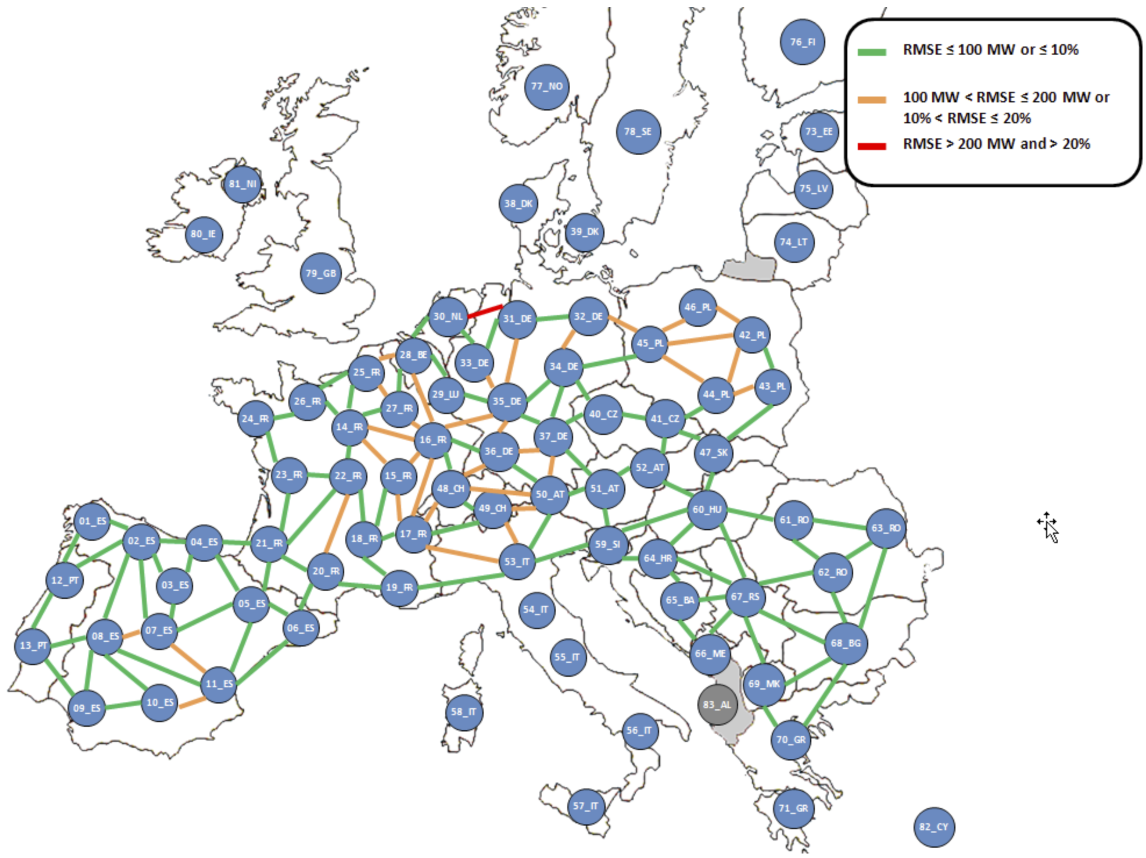
The simplified AC network thus obtained is assumed to follow Kirchhoff’s laws:

- The first law is scrupulously respected.
- The second law, the mesh law, requires allocating an impedance to each equivalent link.

An extra parameter is added to the modelling: each equivalent link hosts an initial/structural flow correction, accounting for the possible asymmetries between load and generation within each area.

The set of impedances and flow corrections can be assessed through an optimisation problem. In a nutshell, the method determines the optimal set of impedances and flow corrections minimising the error between estimated flows (with the simplified grid) and target flows (with the detailed grid) on all equivalent links. This optimisation is done on a sample[3] of flows. The method comes by construction with an error estimator, which offers a critical view on the quality of the equivalent network, and provides a first indication of where it is worth improving the definition of zones.

Figure 3: Root Mean Square Error (RMSE): an error estimator of the reduced grid



[3] The sample can come from actual measurements of flows, or flows generated from a CIM base case ENTSO-E (TYNDP) on which load flows are computed with different load and generation patterns.

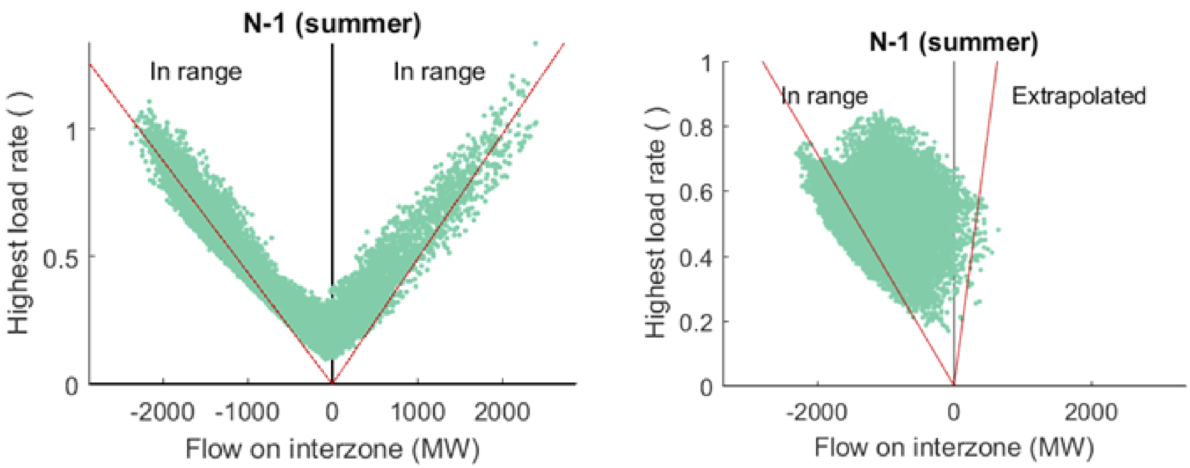
Each equivalent link is assigned a transmission capacity N-1 robust (seasonal and directional). The sample of flows can be used to compute under normal condition and for any given contingency the maximum capacity that can flow on each equivalent link without generating the overload of a single component composing the “border”. Indeed, the sample offers different base cases with different initial loading of actual lines composing the inter-zone. Thus, the transmission capacity of the equivalent link can be estimated over the whole sample, and the capacity value determined within a given risk level.

Depending on the correlation between the flows on the different critical branches and critical outages of each inter-zone, the quality of the resulting equivalent capacity may be variable, which is another indicator of where it is worth improving the definition of zones.

Controllable devices can also be included into the model:

— HVDC are modelled through additional links which have not to respect Kirchhoff’s mesh rule.
— PSTs are modelled through an additional degree of freedom in Kirchhoff’s equations of appropriate meshes, reflecting their phase shifting capability.

Figure 4: Assessment of equivalent capacities: good quality (left) or lower quality (right)



1.2.4 Identification of system needs using a flow-based market model

The identification of system needs for the 2040 horizon starts with a macro-analysis of bottlenecks and their impact on generation mix. The effects of network constraints on generation mix are measured by the difference between two simulations:

— “Copperplate” simulation, in which the transmission grid is assumed to be without constraints, i.e. where network capacities are set to infinite.
— Simulation with grid constraints, in which capacities are limited to the “starting grid” in a first step, and the “starting grid” plus the reinforcements tested during the identification of system needs process for the following steps.

The “copperplate” simulation gives the upper limit of what could be achieved by grid reinforcement to ensure system security and optimise operating costs. On the contrary, the “starting grid” simulation gives the lowest level of system security than can be achieved with the 2030[4] transmission network status after implementation of 2040 demand and generation development.

Several indicators can be inferred from the comparison of these simulations: delta energy not supplied, delta dumped energy, thermal redispatch (increase of more expensive generation and decrease of cheaper generation), etc. The main challenges of each scenario are thus pointed out.

The bottlenecks can be detected through the Marginal Value of the links: this indicator (marginal, €/MW, different for each hour) displays the potential benefits for the system for an extra MW available on a given inter-zone. It points out the first bottlenecks in the system. Not that the indicator only makes sense in a simulation with limited capacities (in a “copperplate” simulation, all the marginal values are equal to zero).

The methodology also builds on the definition by TSOs regarding standard costs for each boundary and for different sizes of reinforcement (as the conventional approach).

For each boundary, the use of indicators like mean marginal value of congestion divided by standard cost of reinforcement allows possible projects for which the benefits should exceed the costs to be identified. Such projects are then tested in the model to determine their benefits and their impact on the main challenges of the scenario. The different projects can be tested individually or by groups.

Step by step, the needs for 2040 are thus identified. The process ends when no new project can be found out that brings more benefits than costs.

This new methodology was tested on the scenario Sustainable Transition 2040 of the TYNDP 2018.

[4] The starting grid assumed in the analysis builds on a full realisation of the TYNDP 2016 projects for the horizon 2030.

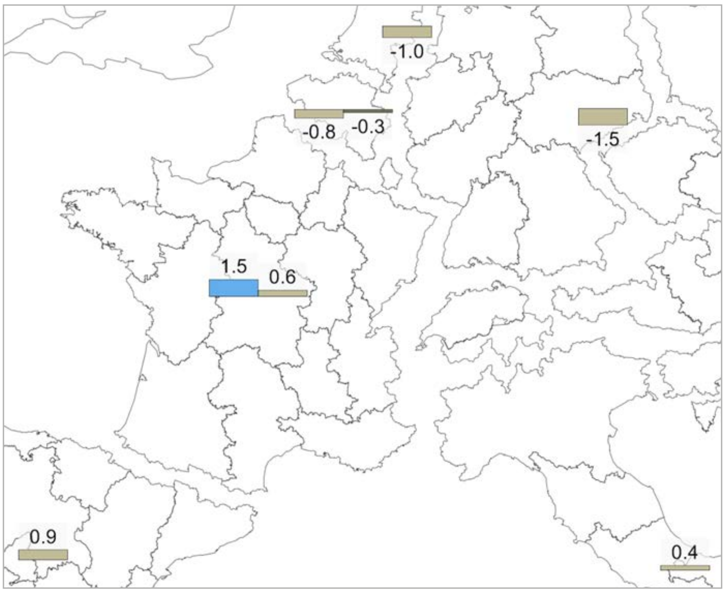
It points out the main challenges of this scenario: Renewable Energy Sources integration in Germany, Spain, Great Britain, Turkey, Ireland, Greece, the Netherlands, Italy and Denmark and nuclear decreases in France, Turkey and Great Britain.

The main bottlenecks are also identified through their mean marginal value (directional). Among them, the following congestions can be mentioned:

- from France to Belgium, Germany, Italy and Switzerland
- from Turkey to Bulgaria and Greece
- from Great Britain to Norway, Denmark, Netherlands, Belgium and France
- from Spain to Portugal
- from Germany to Austria, Czech Republic, Sweden and Poland
- from Greece to Macedonia and Albania
- from Sweden to Finland
- from Denmark, Netherlands and Germany to Norway.

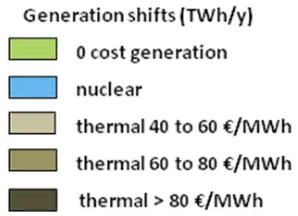
The marginal value displays the potential benefits of the first additional MW of capacity on a given inter-zone but is not necessarily indicative for the following MW. The potential benefits have also to be set against the standard cost of a reinforcement. Therefore, each reinforcement is implemented in the model and thus tested individually. Reinforcements for which benefits exceed costs are then tested by groups. As an example, Figure 5 shows the effects on the system of 1 GW of reinforcement between France and Belgium, France and Germany and both of them. Note that there is almost no competition between these reinforcements.

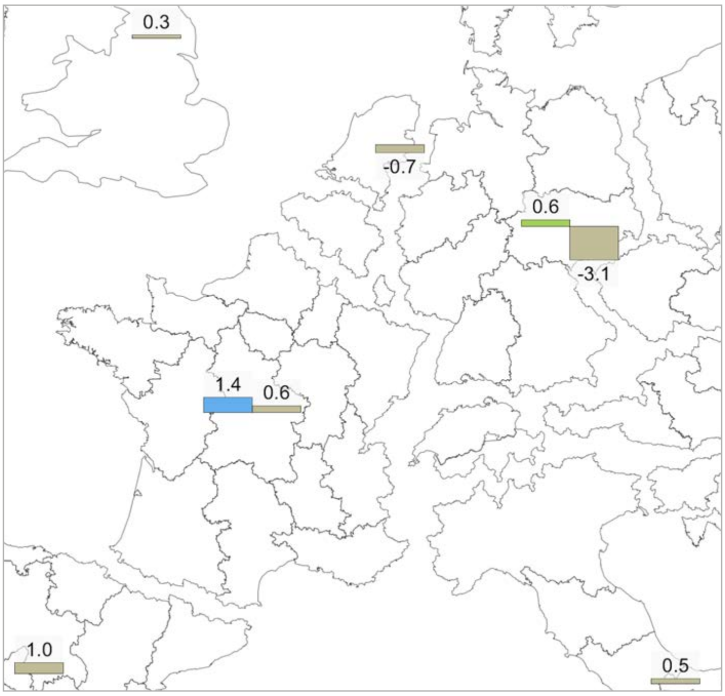
Figure 5: Impact on generation mix and benefits of reinforcements Belgium-France and France-Germany – scenario Sustainable Transition 2040



1 GW of additional capacity between Belgium and France:
Annuity: 6 M€
Generation cost savings: 98 M€/y
Reduction of CO_2 emission: 1.4 Mt/y
Avoided dumped energy: 0.6 TWh/y

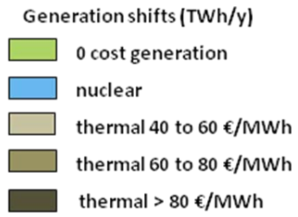
Main drivers of benefits: French nuclear replacing thermal generation

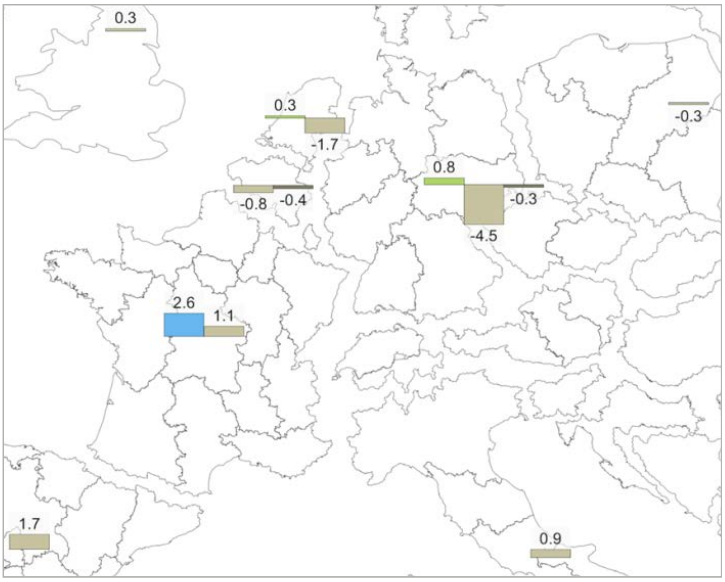




1 GW of additional capacity between France and Germany:
Annuity: 19 M€
Generation cost savings: 116 M€/y
Reduction of CO_2 emission: 1.6 Mt/y
Avoided dumped energy: 0.9 TWh/y

Main drivers of benefits: French nuclear and avoided dumped energy in Germany replacing thermal generation





1 GW of additional capacity between Belgium and France + 1 GW of additional capacity between France and Germany:
Annuity: 25 M€
Generation cost savings: 210 M€/y
Reduction of CO_2 emission: 2.8 Mt/y
Avoided dumped energy: 1.4 TWh/y

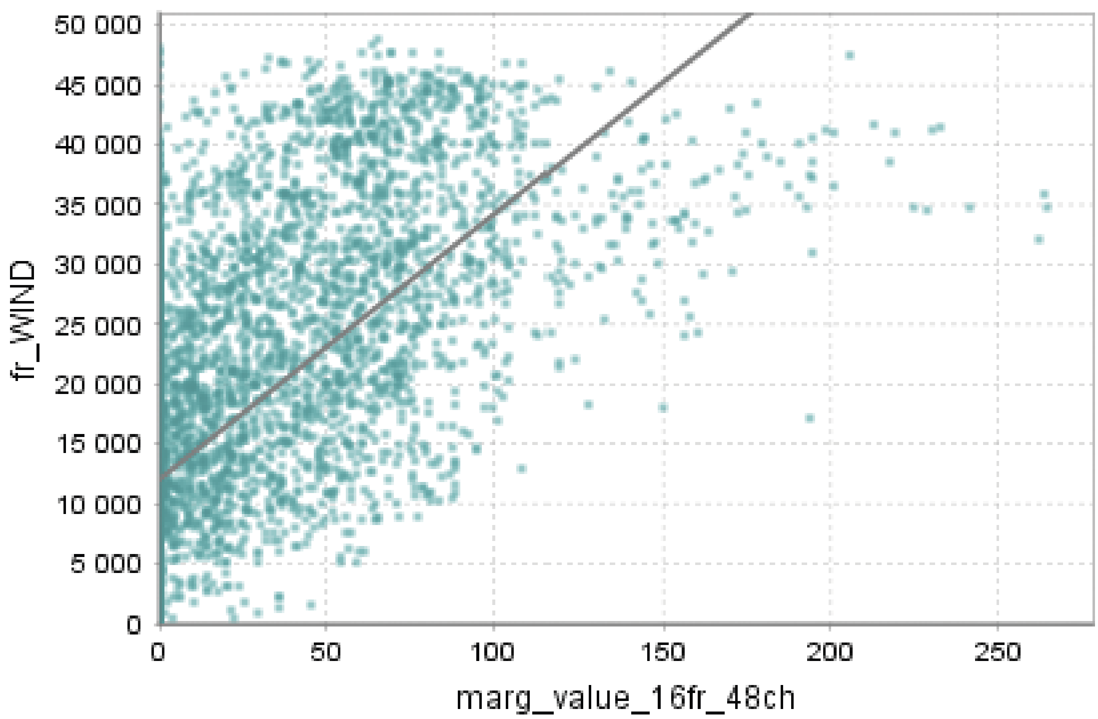
Main drivers of benefits: French nuclear and avoided dumped energy in Germany and the Netherlands replacing thermal generation

To be noted: no competition between both reinforcements (benefits of the group are almost equal to the sum of the benefits of each one) but slightly different arbitrages regarding the location of redispatch

1.2.5 Benefits and challenges of a flow-based market model

The simulation of the interconnected system gives access to a huge database, containing flows for each of the inter-zone links as well as load and generation data for each zone, for every hour of the year and every Monte Carlo scenario. As the transmission grid is AC and highly meshed, a lot of those variables (sometimes correlated) influence the flows, and it can be tricky to determine intuitively the load/generation configurations that cause a constraint. However, statistical analyses of the whole database help to understand what drives flows and constraints. Several methods can be deployed to facilitate the understanding of the electrical system (correlation, principal components analysis, k-means classification, decision tree, etc.). As an example, Figure 6 shows the correlation between the marginal value of congestion between France and Switzerland and wind generation in France.

Figure 6: Correlation between marginal value of a congestion between FR and CH and wind in FR (example)



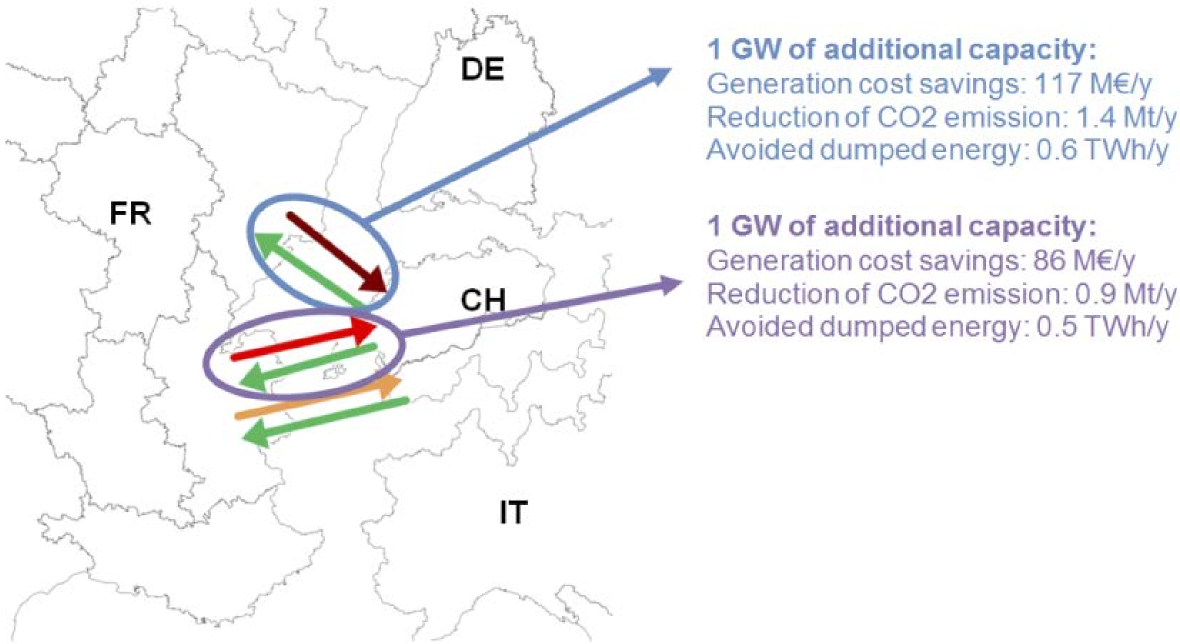
All results of load and generation available at zonal level can be downscaled (for instance via homothetic transformation) to substation level for more detailed network studies (both deterministic and probabilistic). This downscaling appears much more reliable than using a homothetic transformation from national to substation level, and allows to conserve the geographical and inter-modal correlation.

Moreover, the in-depth analysis of constraints presented in the previous paragraph allows study teams to identify and target the main load/generation/exchanges configurations (representative and constrained) to be analysed with tools that model the entire nodal grid.

The outcomes of a "flow-based" market model are more detailed than those of a "classical" NTC market model, which allows to focus on the relevant areas of the grid. Figure 7 below provides an example with the boundary between France and Switzerland – one of the main challenging boundary of the scenario Sustainable Transition 2040. This boundary is divided into three inter-zones of which two are highly congested.

The benefits and the impact on generation mix are not the same between both CH-FR inter-zones. The north of the boundary seems to be more challenging, which cannot be identified directly with a NTC market study.

Figure 7: Congestion and impact of reinforcement on the different inter-zones between France and Switzerland



1.2.6 Conclusion

ENTSO-E has, as part of the Identification of System Needs study, tested a new and innovative approach to assess future capacity needs in the European electrical system. The proposed approach to incorporate the network in market modelling is simplified yet respecting the fundamental laws of physics and is therefore closer to the actual physical grid. It provides a good quality of flow estimates on the macro corridors if the definition of zones is adapted to the structure and the weaknesses of the grid. The approach allows simulating even very large systems such as the European one, while producing detailed results using a sequential and probabilistic approach which is necessary to capture properly load and generation behaviours and dynamics.

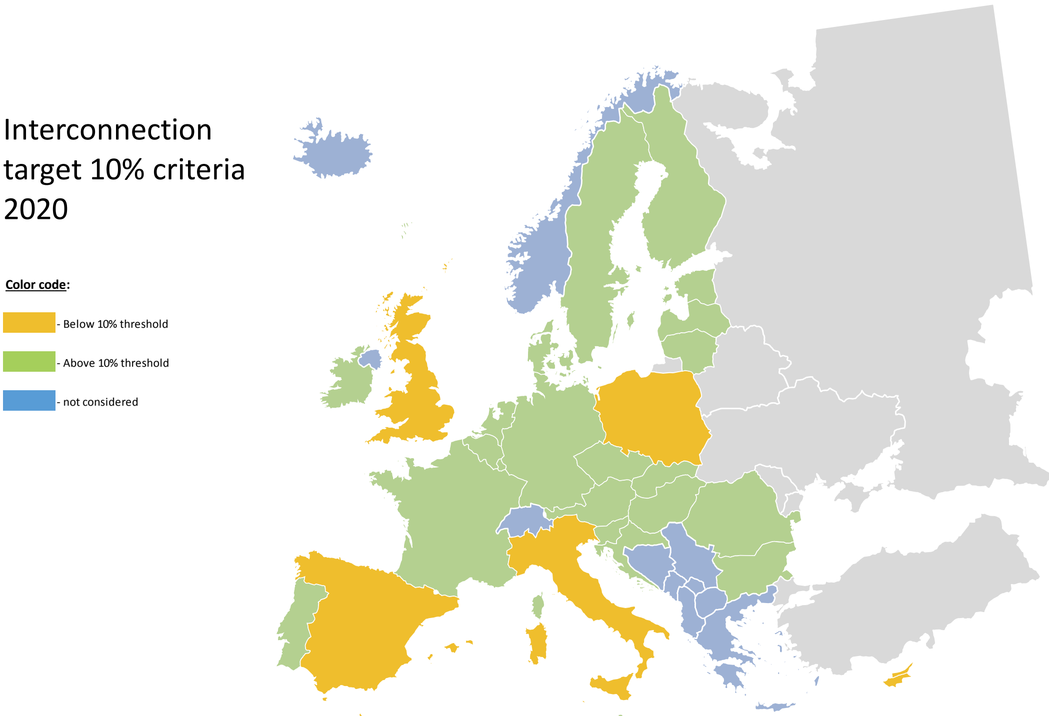
Flow-based market studies produce results on their own, but also help building representative and valuable snapshots and provide data constituting quality inputs for detailed grid studies, which remain essential to precisely analyse constraints on the entire network and design efficient and realistic reinforcements.

It can be concluded that the methodology is very promising for long-term studies where the level of generation and demand are completely different from the current ones, with high uncertainties regarding their specific location, and for which the granularity of the expected results is not too fine. It enables a real European approach as the whole system is simulated at once and reinforcements are identified while the relevant amount of detail is considered. Furthermore, the approach may developed further, e.g., towards a more appropriate definition of zones and the assessment of the needs inside the countries.

1.3
Interconnection targets

Figure 8 shows the previous 10% Interconnection Targets for 2020 as defined by EC.

Figure 8: Previous 10% Interconnection Targets for 2020 as defined by EC



In comparison to that, the new Interconnection Target for the three new 2040 scenarios of the ENTSOs are shown in Figure 9. The new Interconnection Targets were proposed operationalised by considering any of the following three thresholds[5]:

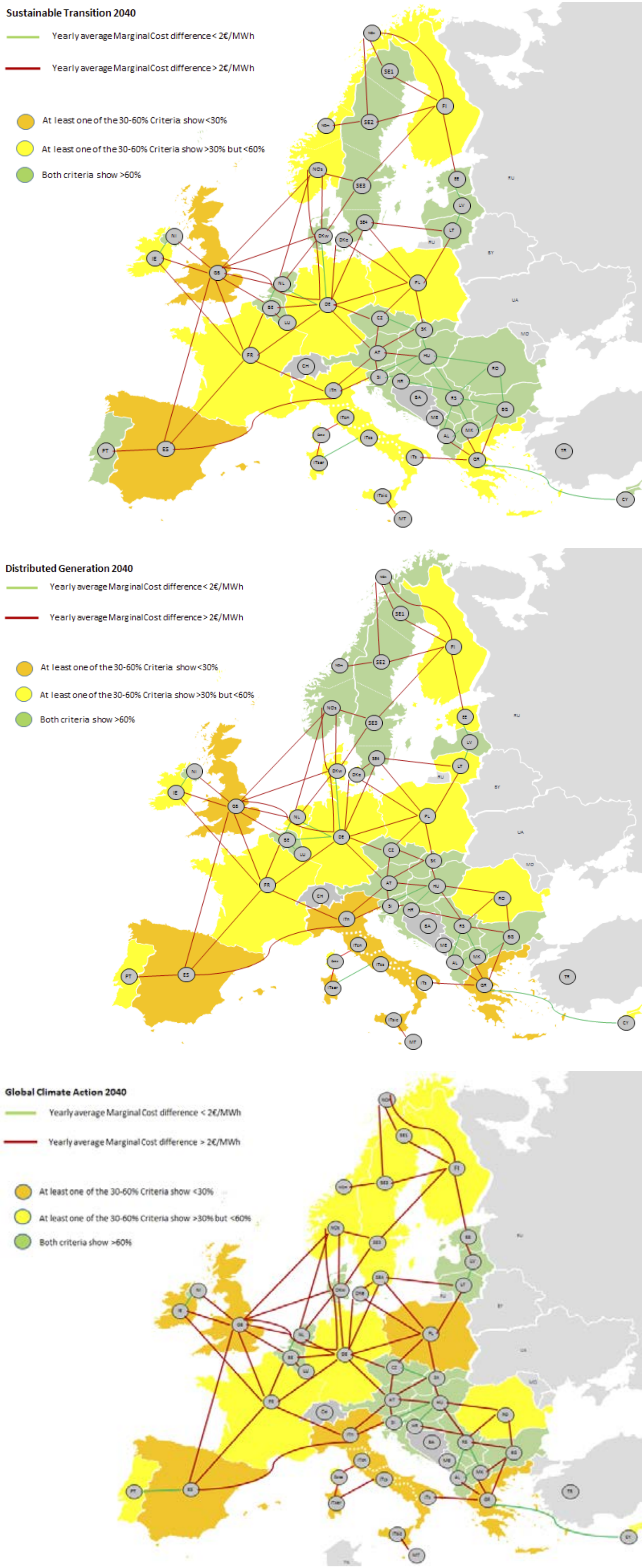
— A well-functioning internal market should lead to competitive electricity prices for all Europeans. Member States should therefore aim at minimising differences in their wholesale market prices. Additional interconnections should be prioritised if the price differential exceeds an indicative threshold of 2€/MWh between Member States, regions or bidding zones to ensure all consumers benefit from the internal market in a comparable manner. The higher the price differential, the greater the need for urgent action.

— Every Member State should ensure that peak demand can be met in all conditions through a combination of domestic capacity and imports. Therefore countries where the nominal transmission capacity of interconnectors is below 30% of their peak load should urgently investigate options of further interconnectors.

— The further deployment of renewable energy should not be hampered by a lack of export capacity. Renewable production in any Member State should be optimally used across Europe. Therefore countries where the nominal transmission capacity of interconnectors is below 30% of installed renewable generation capacity should urgently investigate options of further interconnectors.

[5] Communication from EC https://ec.europa.eu/energy/sites/ener/files/documents/communication_on_infrastructure_17.pdf

Figure 9: New Interconnection Targets for 2040[6]



The following countries were considered for the computation of interconnectivity levels at the EU perimeter (including Switzerland and Norway, as recommended by the Interconnection Target Expert Group) and for the computation of all the input network and market related data (nominal transmission capacities of the interconnectors, net generating capacity, peak load figures):

AT
BE
BG
CH
CY
CZ
DE
DK
EE
ES
FI
FR
GB
GR
HR
HU
IE
IT
LT
LU
LV
MT
NI
NL
NO
PL
PT
RO
SE
SI
SK

[6] Germany-Luxembourg is one bidding zone.

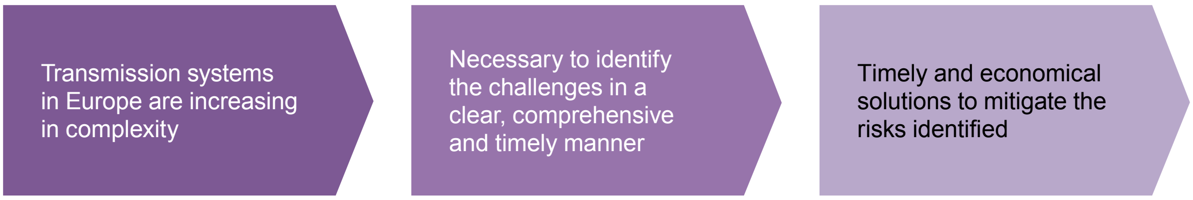
1.4
System dynamic and operational challenges

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:

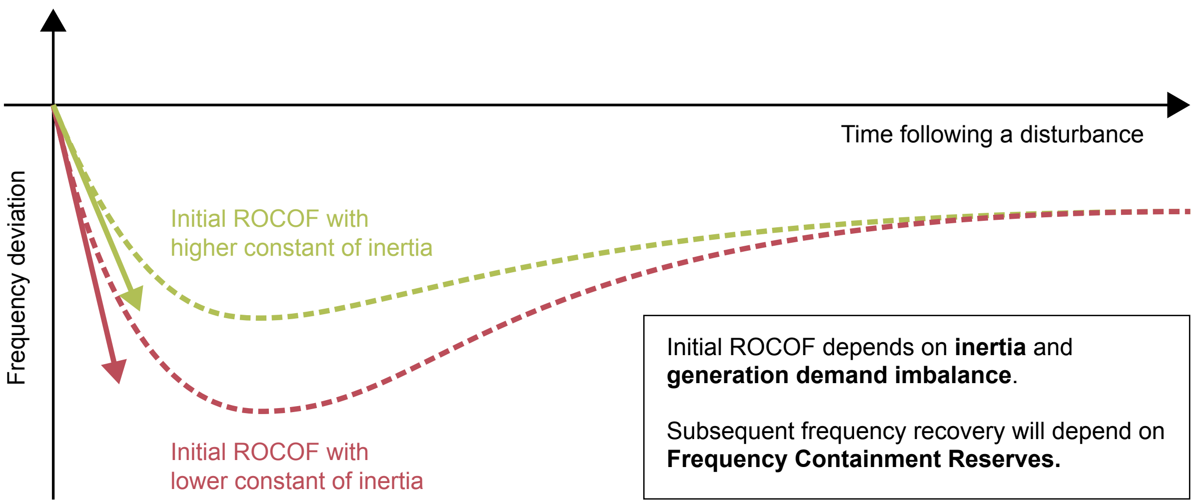
— "'frequency containment reserves (FCR)' means the active power reserves available to contain system frequency after the occurrence of an imbalance;
— 'frequency restoration reserve (FRR)' means the active power reserves available to restore system frequency to the nominal frequency and for synchronous 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.

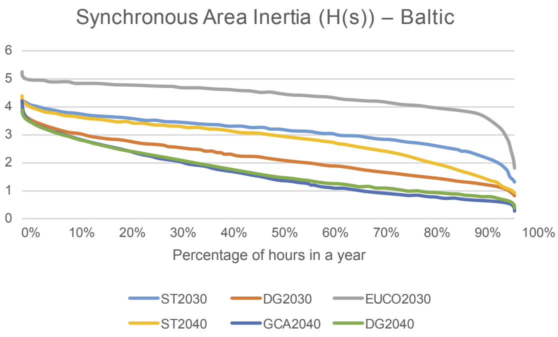
Figure 10: Rate of Change of Frequency depending on inertia

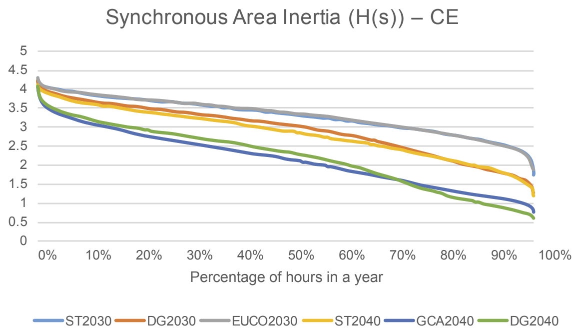


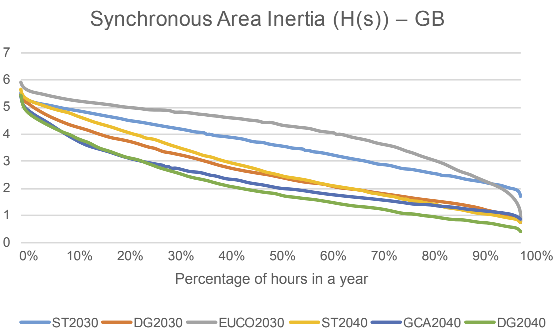
Taking into account the TYNDP 2018 market results, the duration curves in Figure 11 present the percentage of hours in a full year where, for all Synchronous Areas, the intrinsic inertia from generators is above a given value.

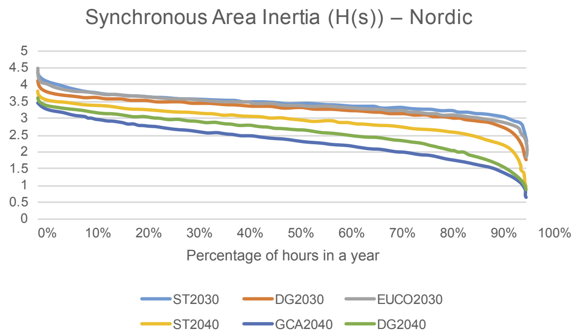
This estimated equivalent system inertia H(s) is calculated on the basis of online generators' capacity. Inertia contribution from demand is neglected because it is very small.

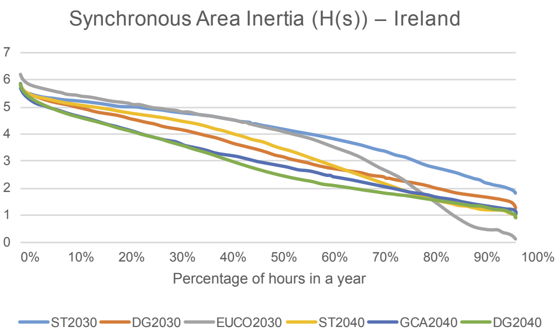
Figure 11: Duration curves of estimated synchronous areas equivalent inertia (H(s))











System inertia trends

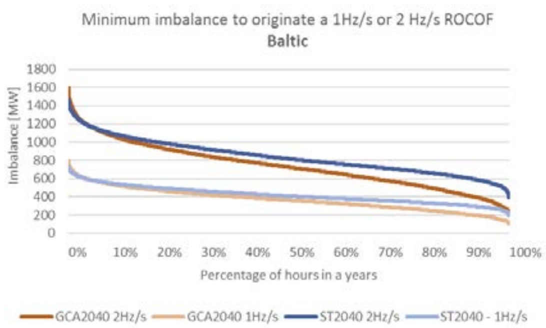
As we move from the situations in 2030 to the 2040 visions with a higher integration of RES and more distributed generation, inertia in all synchronous areas will decrease. The reduction is noticeable even in a large area such as Continental Europe.

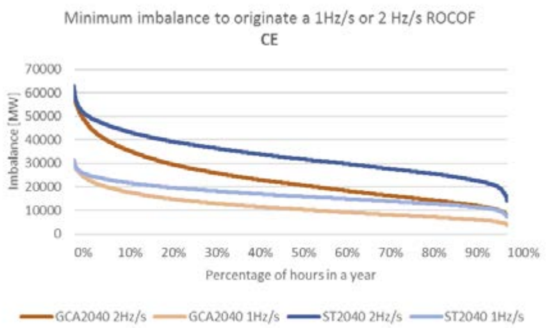
With very low inertia, the system becomes more vulnerable to experience high frequency excursions and even blackout as result of a relatively low mismatch between generation and demand. The impact of this inertia reduction is especially significant in small synchronous areas.

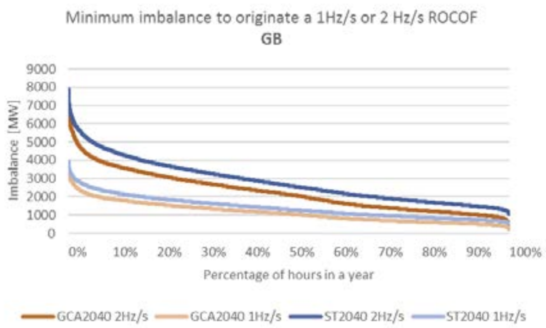
The figures in Figure 12 present the minimum imbalance necessary to trigger a fixed ROCOF for all the hours of the year in the different synchronous areas using the estimated values of inertia. As previously described above, the initial ROCOF depends on the imbalance between load and generation and the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

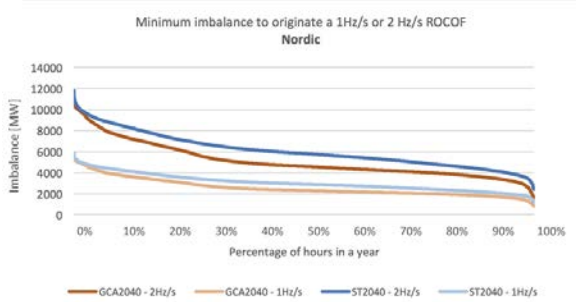
— Two scenarios are used: a situation with low RES, Sustainable transition 2040, and a situation with high RES, Global Climate Action 2040.
— Two ROCOF values are used: 1 Hz/s and 2 Hz/s. The higher, 2 Hz/s, representing a typical value for defence plans and RfG withstand capability for generators.

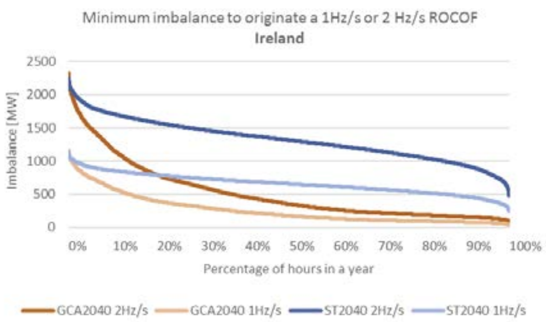
Figure 12: Duration curves of estimated synchronous areas minimum imbalance that would originate a given ROCOF











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.

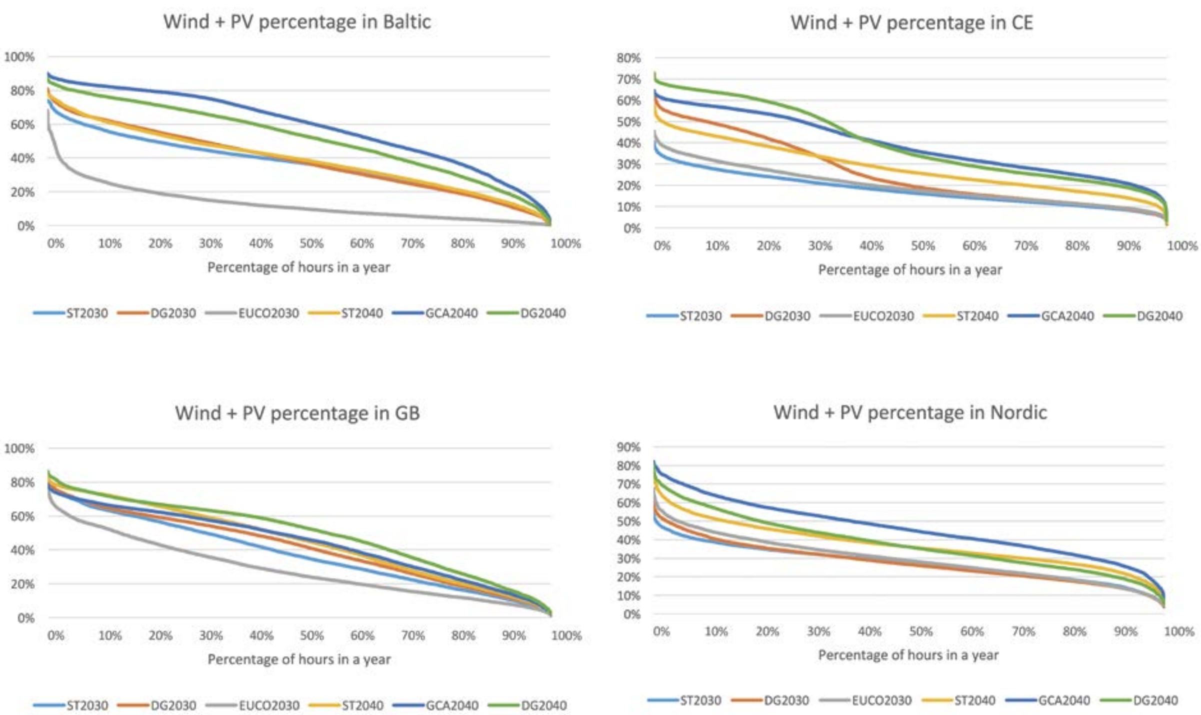
[8] Implementation Guiding Document – High Penetration of Power Electronic Interfaced Power Sources. https://www.entsoe.eu/Documents/Network%20codes%20documents/Implementation/CNC/170322_IGD25_HPoPEIPS.pdf
[9] An example of related investigations is the MIGRATE project - Massive InteGRATion of power Electronic devices. https://www.h2020-migrate.eu/

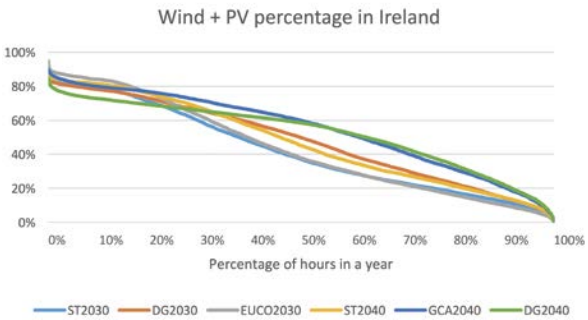
1.3.3 Flexibility needs

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%).

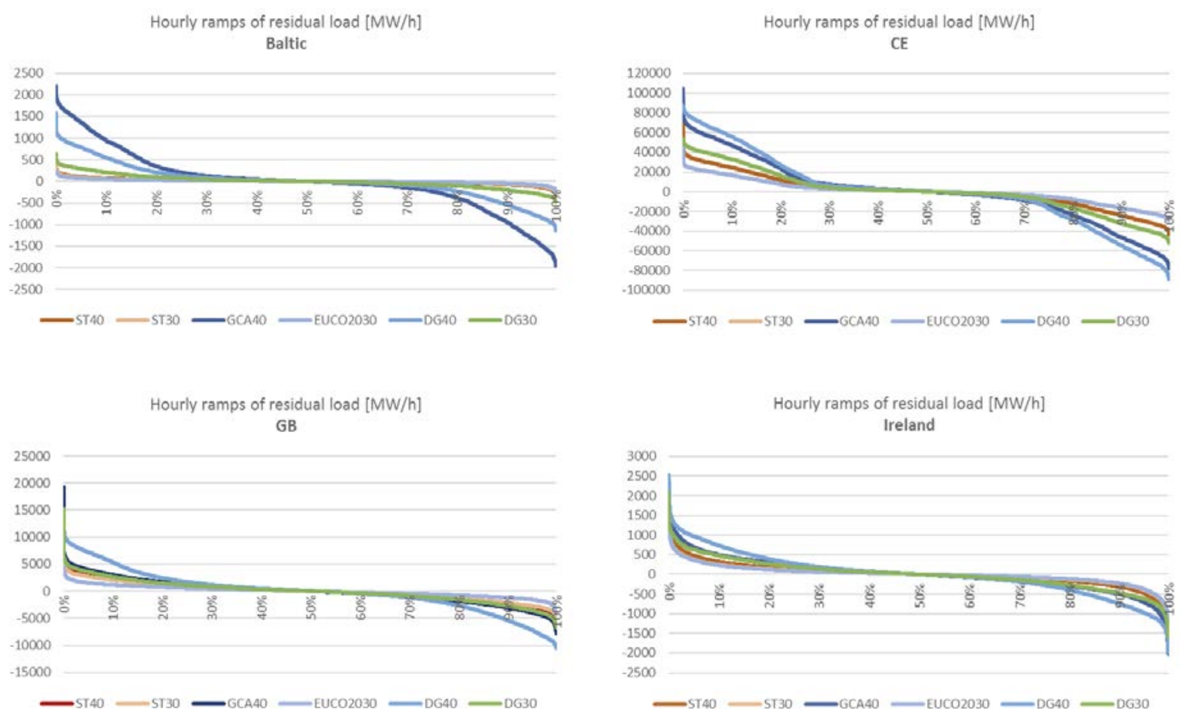
Reduced amount of controllable units lead to high flexibility needs in normal operation.

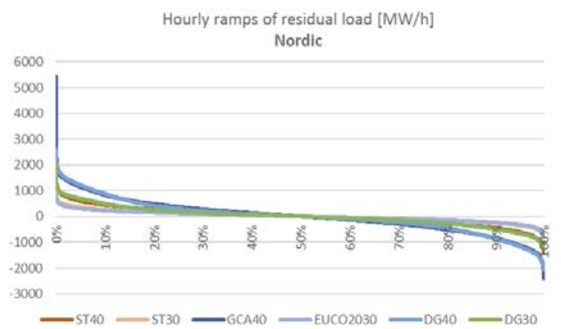
The variability in the power output from RES, which is driven by the variability of the primary energy resource, must be balanced, including forecast output deviations, in order to maintain the frequency equilibrium.

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).

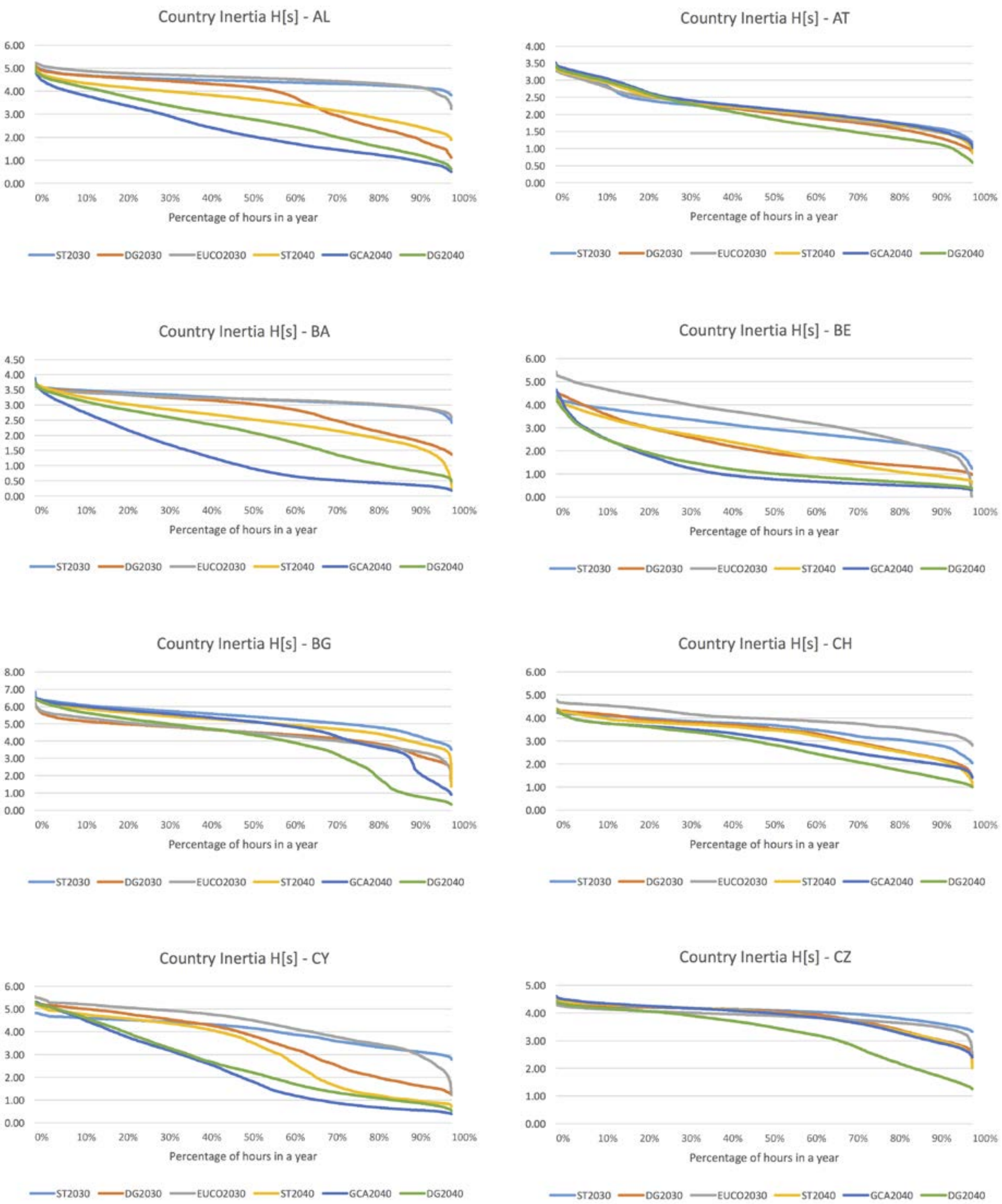
1.3.7 Additional background information Part I – Estimated inertia in all countries

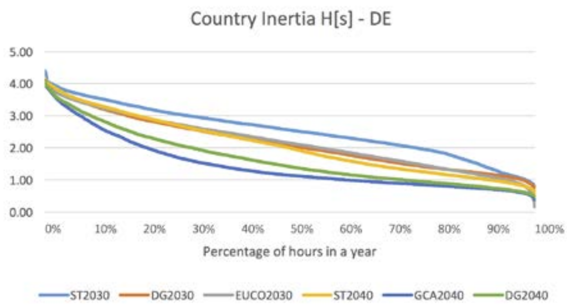
The plots in Figure 15 represent the estimated duration curve of inertia for each country in the ENTSO-E area. The plots are based on the market study results for all visions of the TYNDP 2018. Equivalent inertia for each country, presented as H[s], is calculated on the basis of total online capacity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

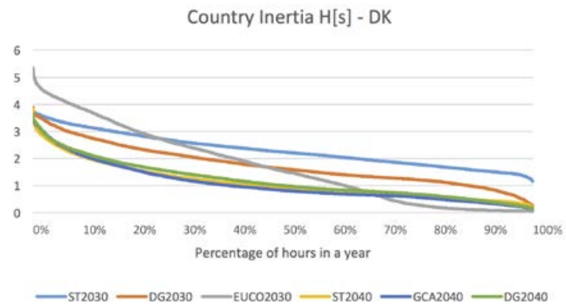
The estimation provides an image of the equivalent inertia resulting from the generation mix in each country for all the hours of the year. In general terms, countries presenting higher values of inertia have a generation mix with more share of synchronous generation (which may also include RES from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

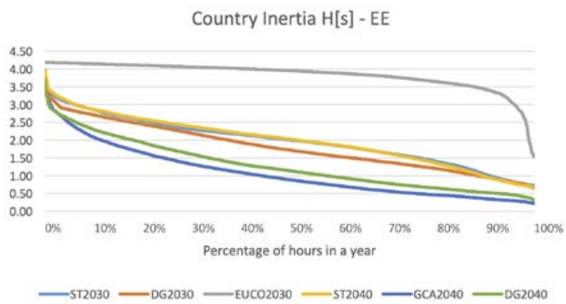
The following plots do not display an assumption of sufficient or insufficient inertia, or even of higher or lower RES integration. They only portray a supplementary insight into the level of the inherent diversity and internal variability of the different countries regarding equivalent inertia.

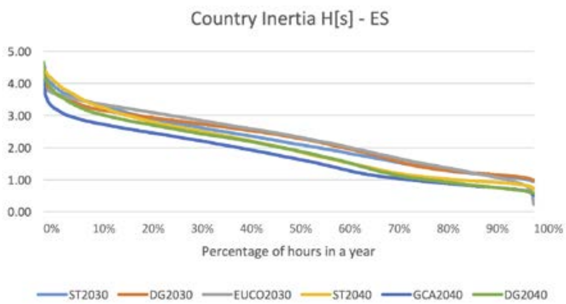
Figure 15: Duration curves of countries' estimated equivalent inertia (H(s))

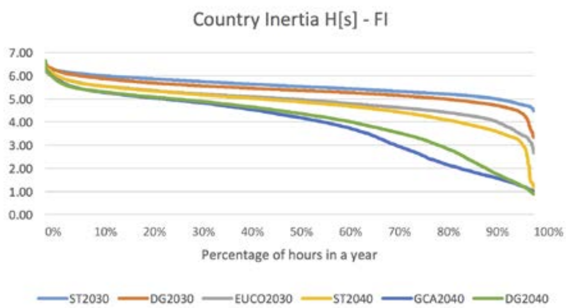


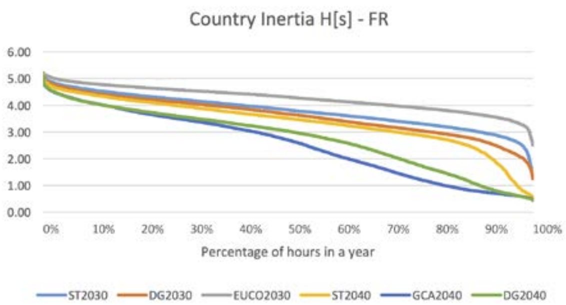

Country Inertia H[s] - DE
5.00 4.00 3.00 2.00 1.00 0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

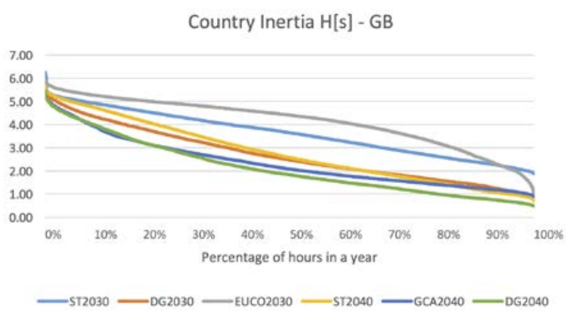

Country Inertia H[s] - DK
6 5 4 3 2 1 0
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040


Country Inertia H[s] - EE
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] - ES
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] - FI
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] - FR
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] - GB
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
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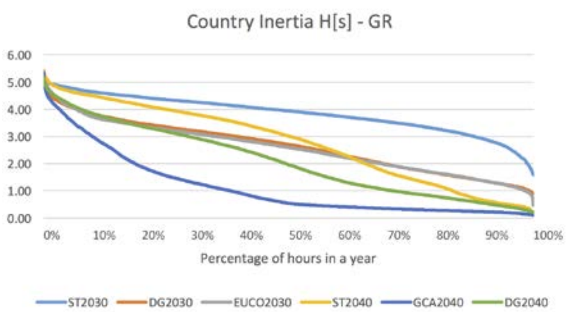
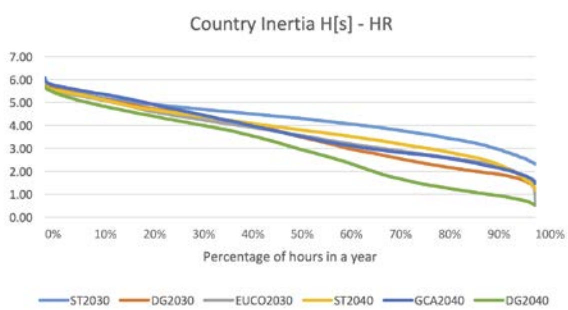
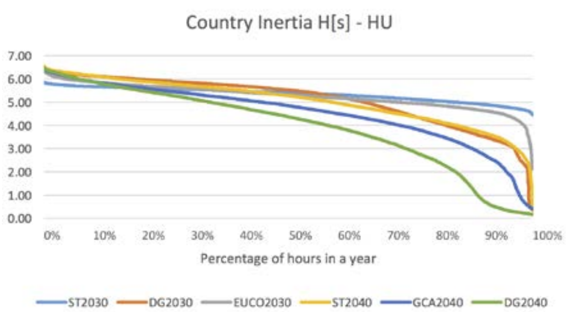
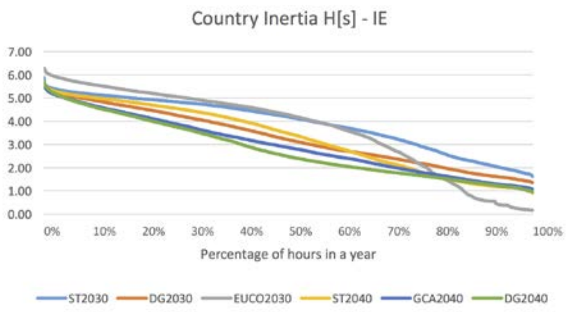
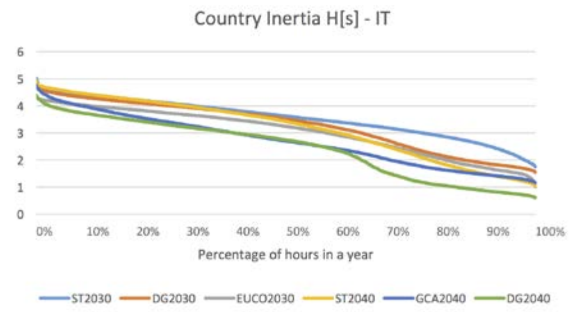
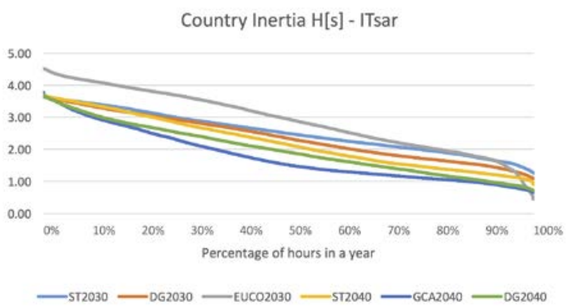

Country Inertia H[s] - GR
6.00 5.00 4.00 3.00 2.00 1.00 0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90% 100%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040


Country Inertia H[s] - HR
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] - HU
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] - 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
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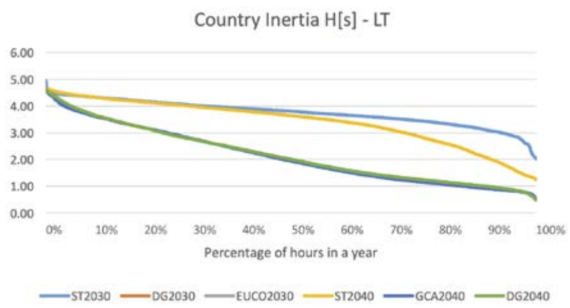
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Percentage of hours in a year
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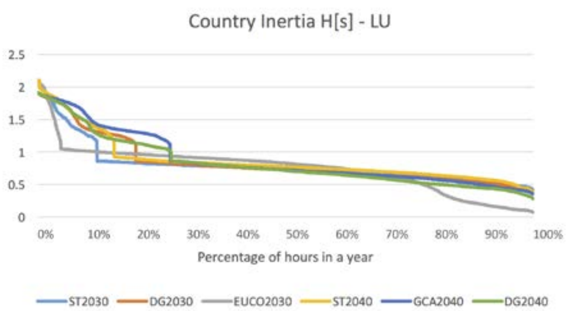
Country Inertia H[s] - LU
Percentage of hours in a year
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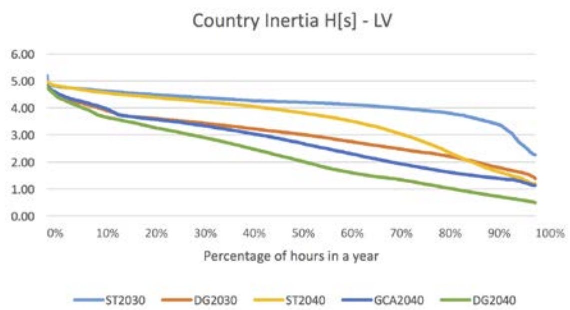
Country Inertia H[s] - LV
Percentage of hours in a year
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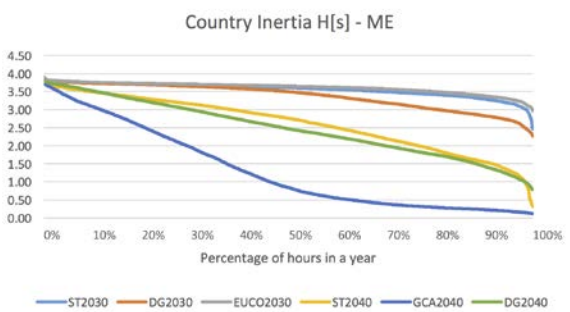
Country Inertia H[s] - ME
Percentage of hours in a year
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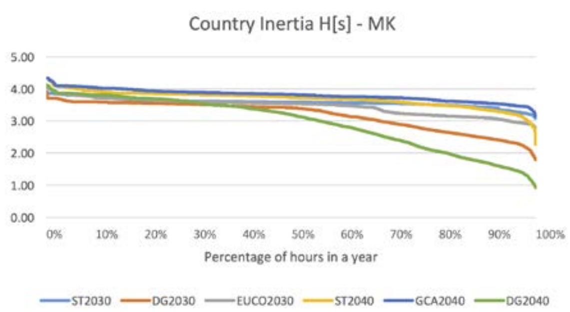
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Percentage of hours in a year
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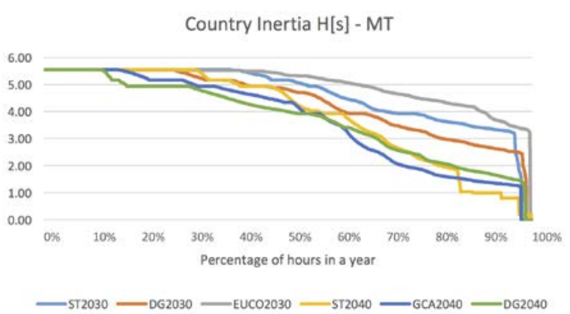
Country Inertia H[s] - MT
Percentage of hours in a year
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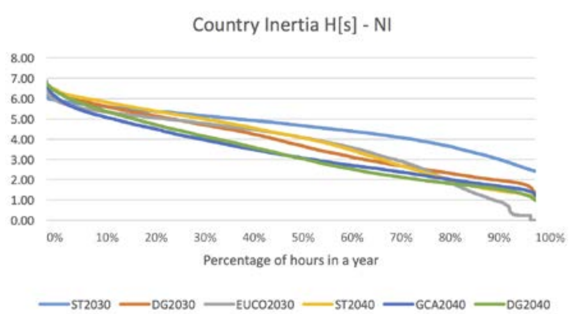
Country Inertia H[s] - NI
Percentage of hours in a year
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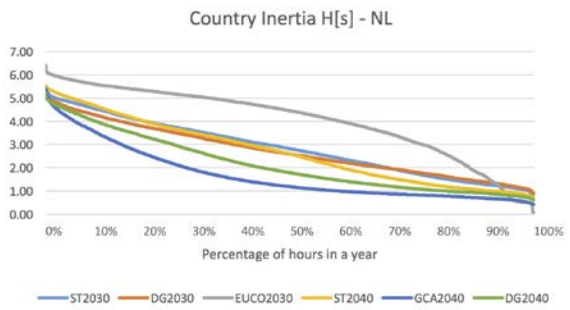
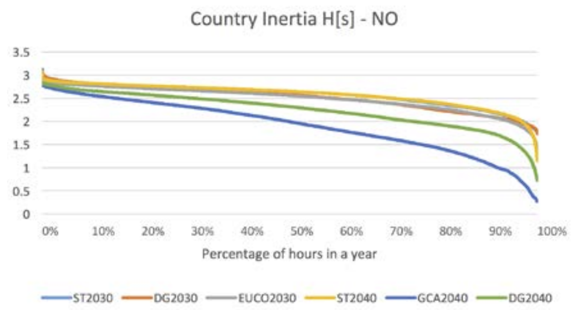
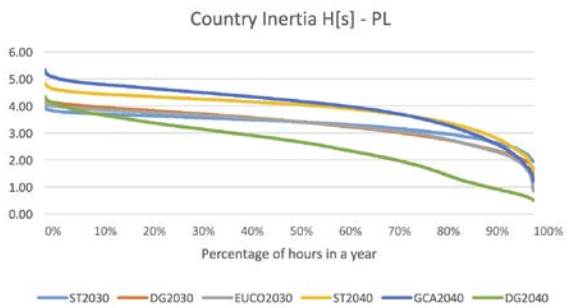
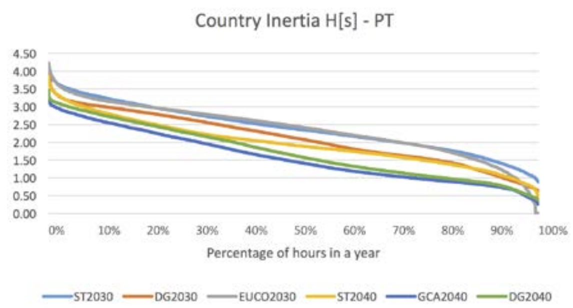

Country Inertia H[s] - NL
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040


Country Inertia H[s] - NO
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040


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


Country Inertia H[s] - PT
Percentage of hours in a year
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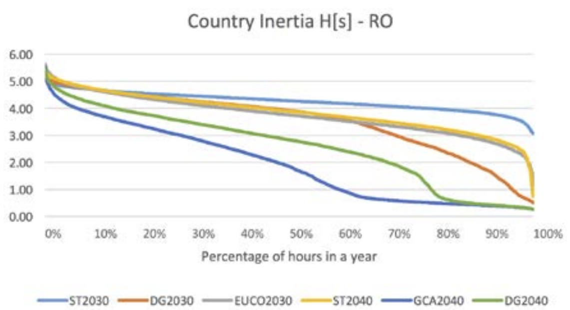
Country Inertia H[s] - RO
Percentage of hours in a year
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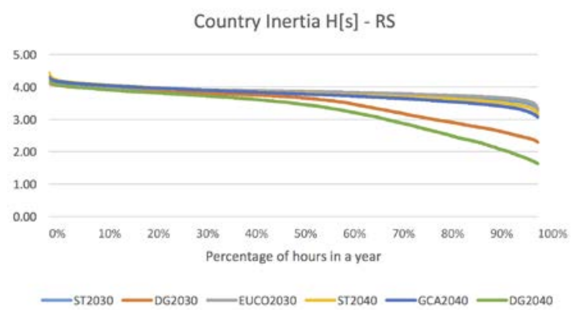
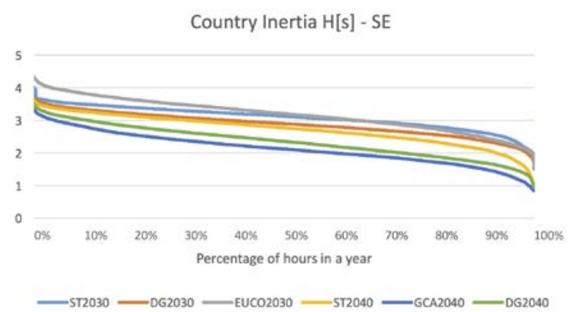
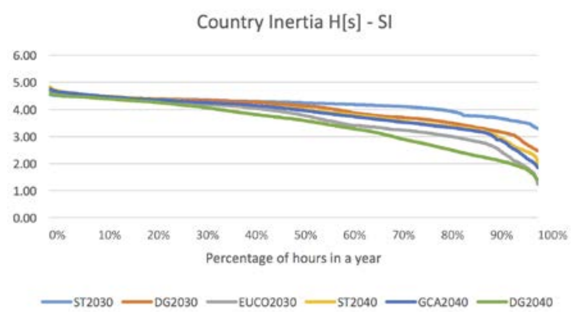

Country Inertia H[s] - RS
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040


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


Country Inertia H[s] - SI
Percentage of hours in a year
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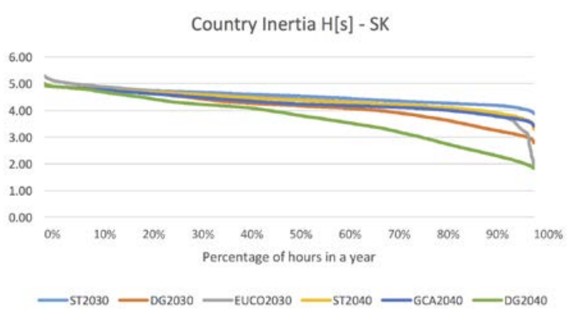
Country Inertia H[s] - SK
Percentage of hours in a year
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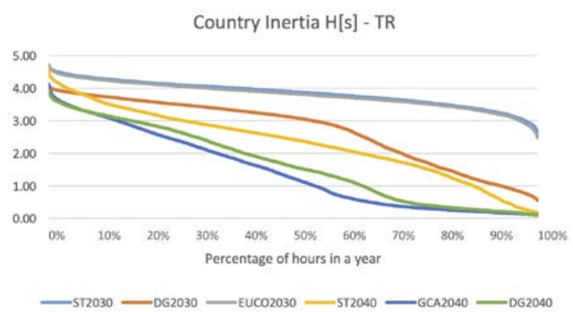

Country Inertia H[s] - TR
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040 GCA2040 DG2040

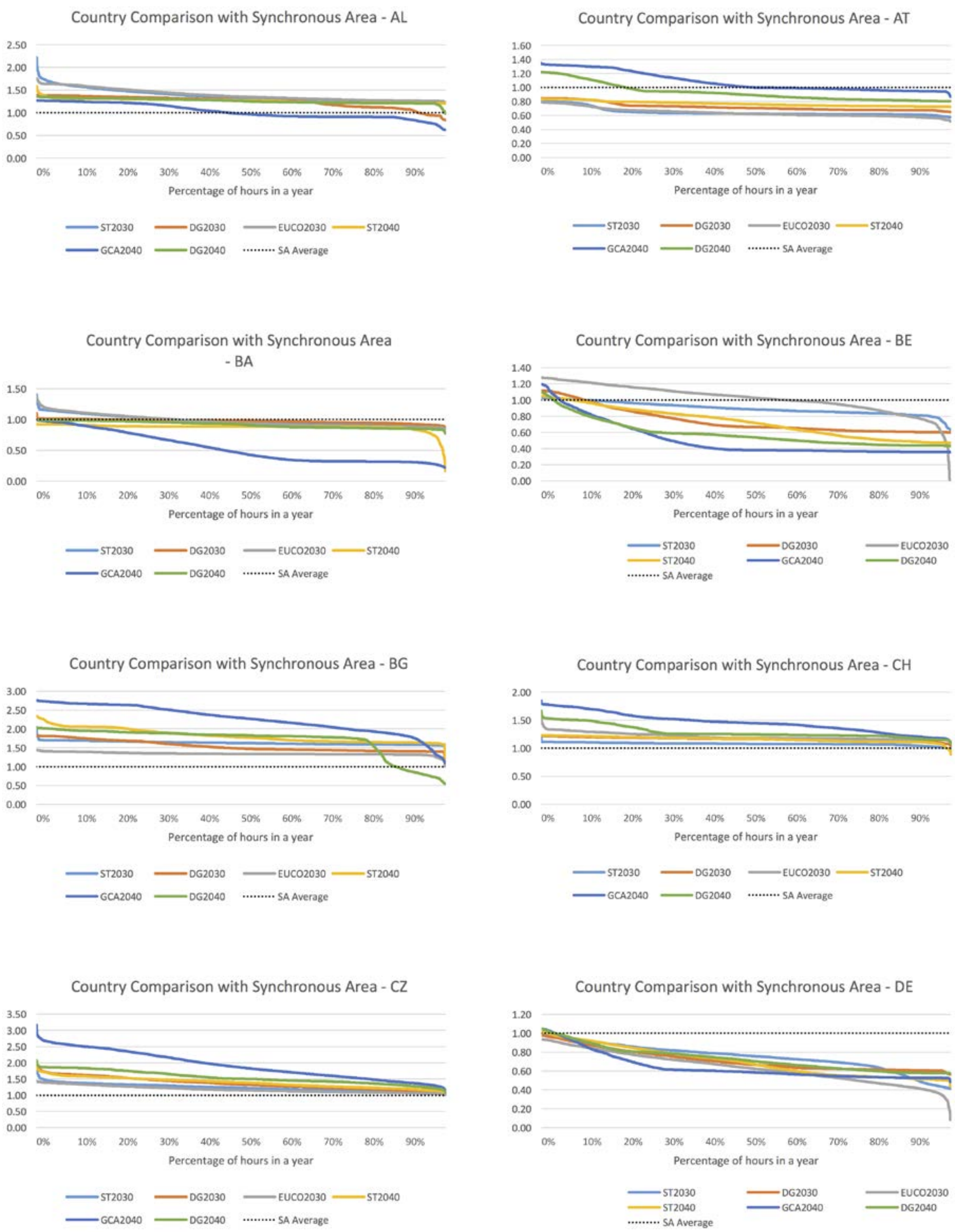
Part II – Country inertia comparison with synchronous area

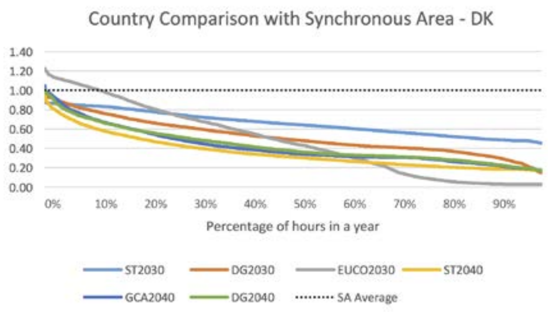
The plots in Figure 16 depict the duration curves of inertia for each country in the ENTSO-E area compared with the respective synchronous area average.

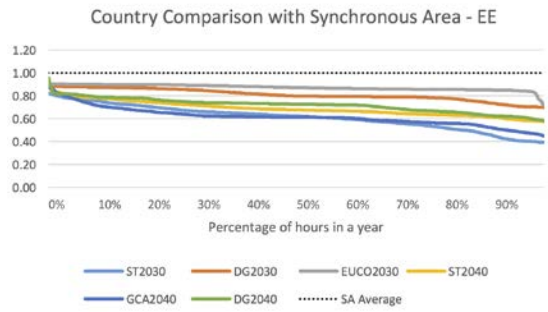
A value of 1 means that the inertia in a given hour is the same as the synchronous area average. Values below 1 do not show insufficient inertia, they only show that the country is below synchronous area average during that number of hours. Similarly, values above 1 show that the country is above synchronous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

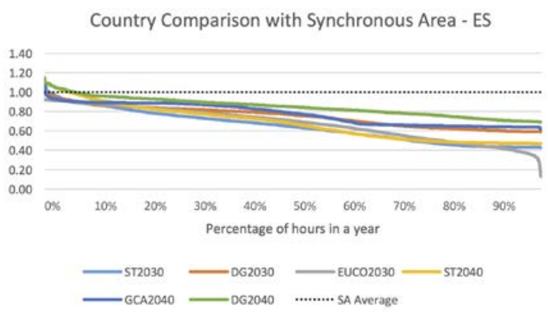
The following plots display the variability of each country regarding the comparison with the respective synchronous area average. Although a trend can be observed in the duration curves, depending on the hour, this comparison can vary significantly and can show values above or below 1.

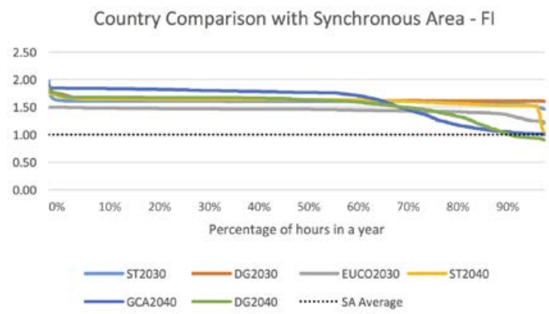
Figure 16: Duration curves of countries' inertia relative comparison with synchronous area

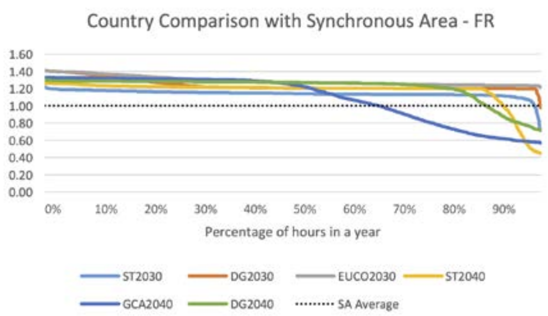


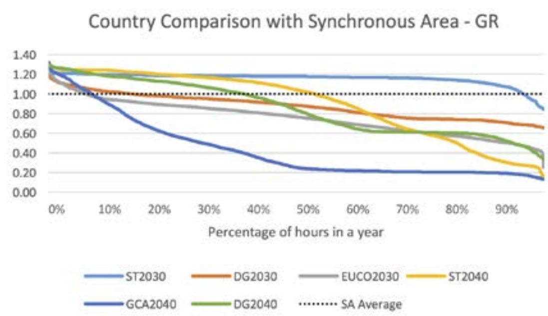

Country Comparison with Synchronous Area - DK
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

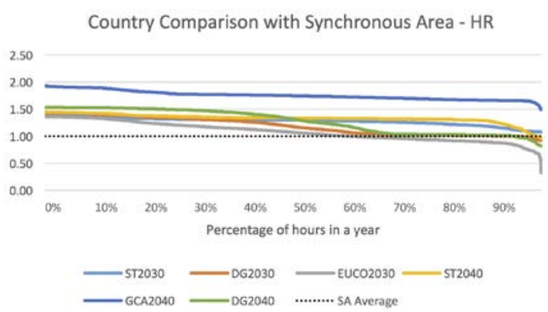

Country Comparison with Synchronous Area - EE
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

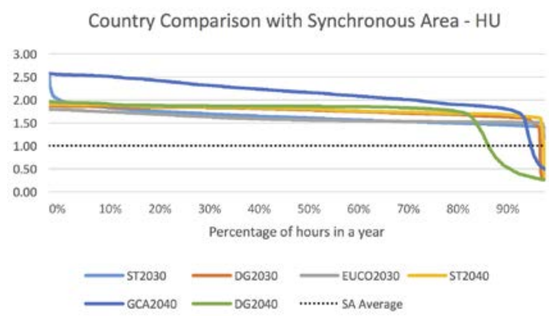

Country Comparison with Synchronous Area - ES
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

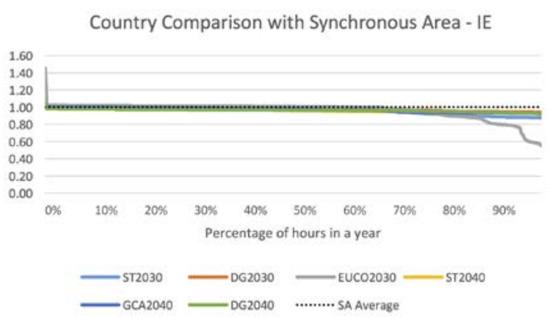

Country Comparison with Synchronous Area - FI
2.50
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

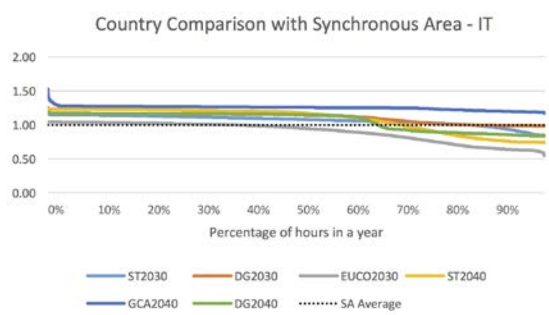

Country Comparison with Synchronous Area - FR
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

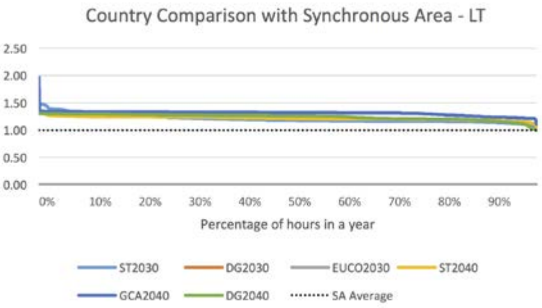

Country Comparison with Synchronous Area - GR
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

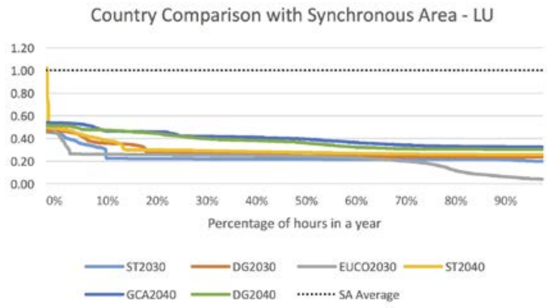

Country Comparison with Synchronous Area - HR
2.50
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

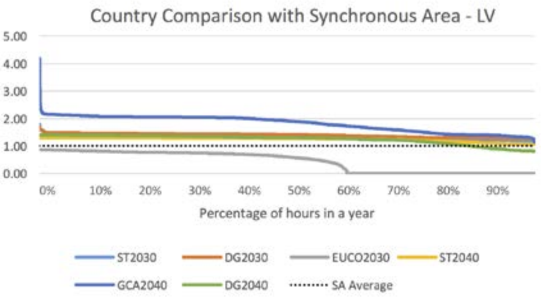

Country Comparison with Synchronous Area - HU
3.00
2.50
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

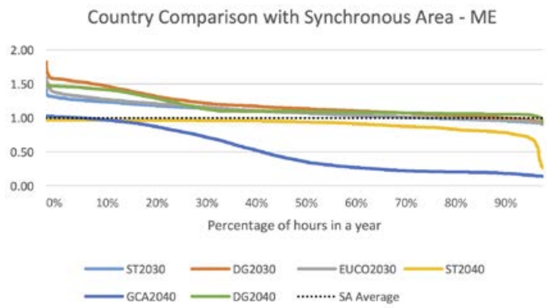

Country Comparison with Synchronous Area - IE
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

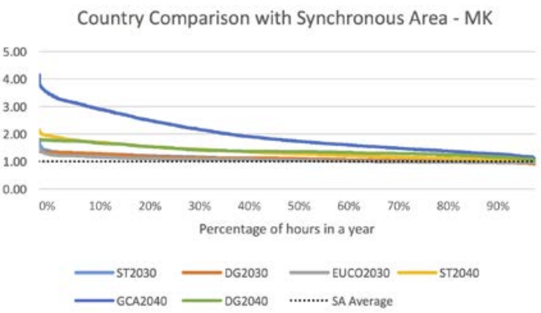

Country Comparison with Synchronous Area - IT
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

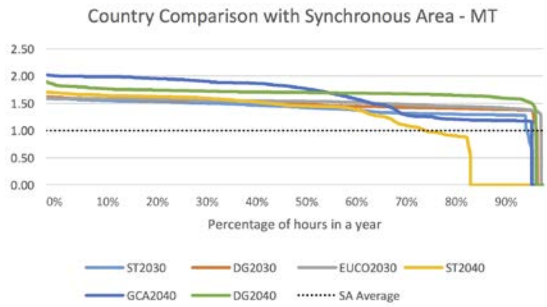

Country Comparison with Synchronous Area - LT
2.50
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

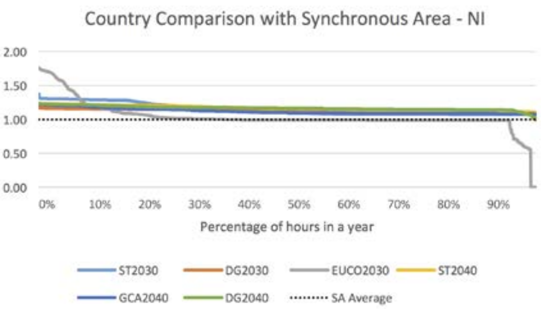

Country Comparison with Synchronous Area - LU
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

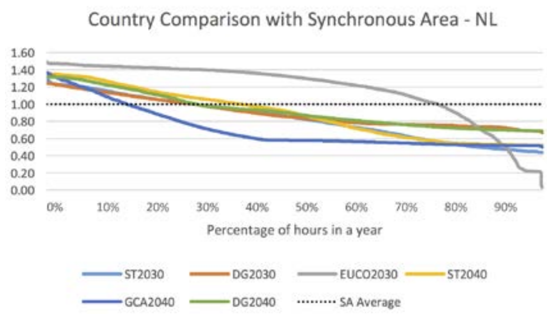

Country Comparison with Synchronous Area - LV
5.00
4.00
3.00
2.00
1.00
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

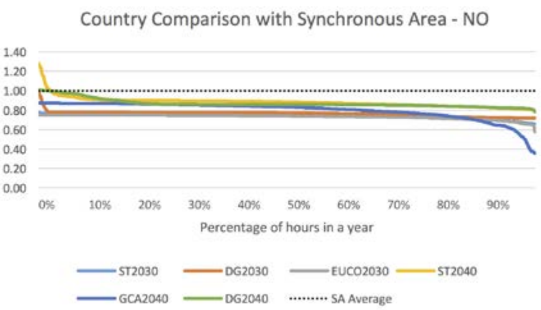

Country Comparison with Synchronous Area - ME
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

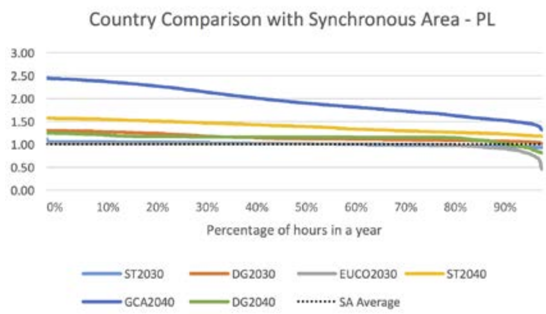

Country Comparison with Synchronous Area - MK
5.00
4.00
3.00
2.00
1.00
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

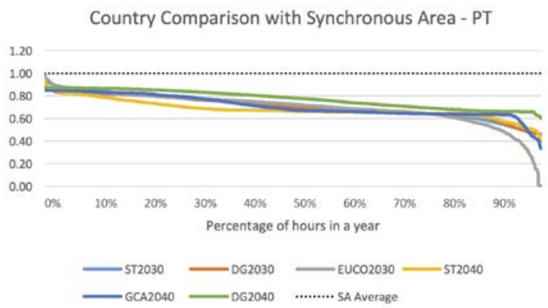

Country Comparison with Synchronous Area - MT
2.50
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

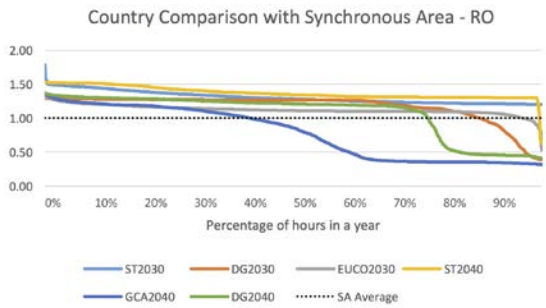

Country Comparison with Synchronous Area - NI
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

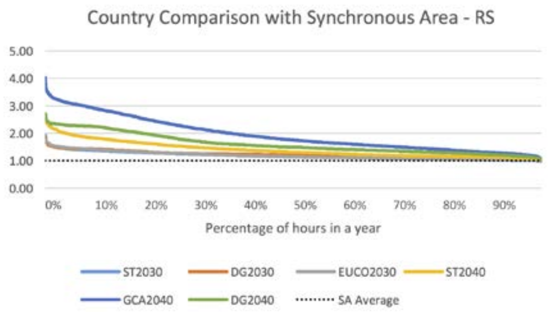

Country Comparison with Synchronous Area - NL
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

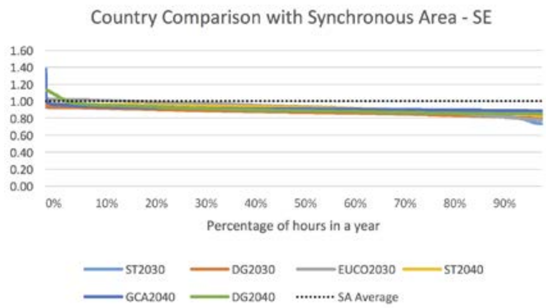

Country Comparison with Synchronous Area - NO
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

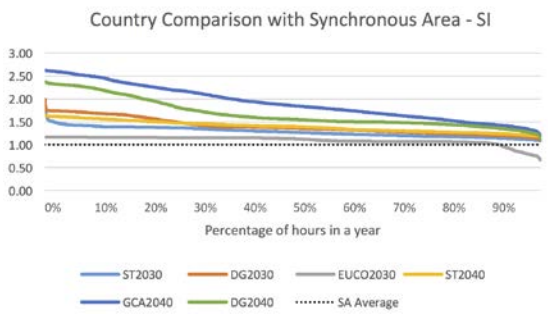

Country Comparison with Synchronous Area - PL
3.00
2.50
2.00
1.50
1.00
0.50
0.00
0% 10% 20% 30% 40% 50% 60% 70% 80% 90%
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

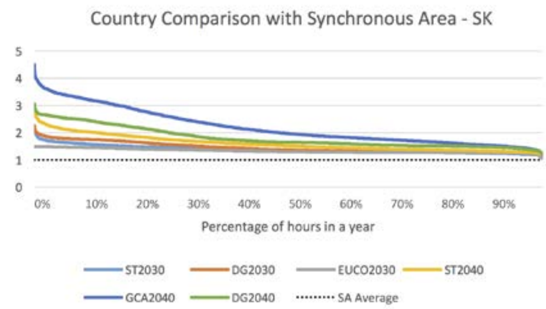

Country Comparison with Synchronous Area - PT
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average

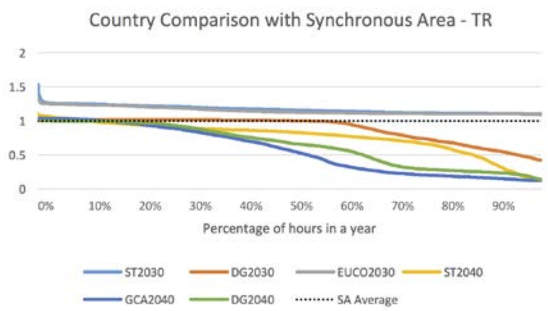

Country Comparison with Synchronous Area - RO
Percentage of hours in a year
ST2030 DG2030 EUCO2030 ST2040
GCA2040 DG2040 SA Average


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


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


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


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


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

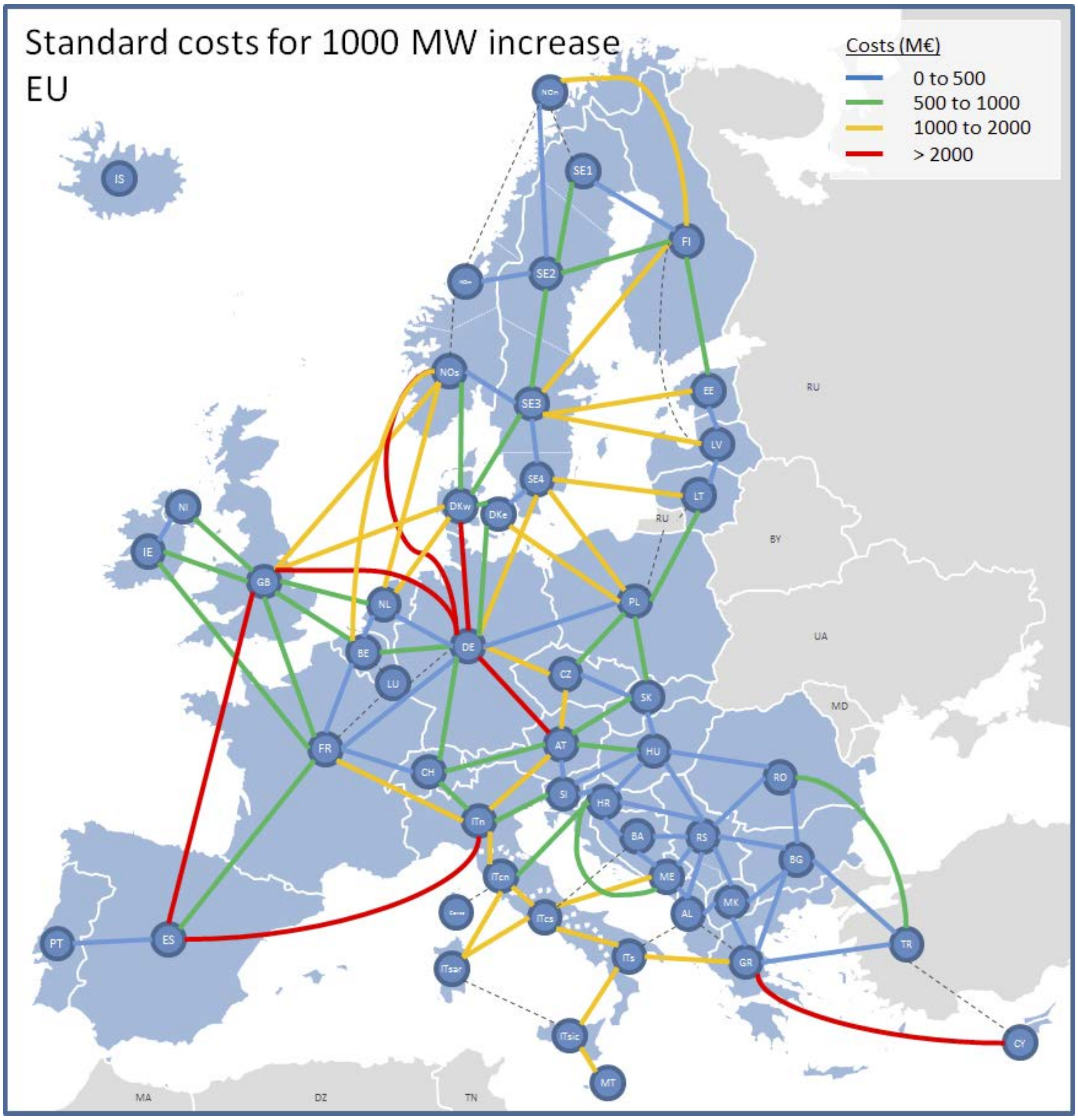
1.5

Additional figures

1.4.1 Standard costs

Figure 17 below gives an indication of the standard costs that have been used to identify the proper capacity needs for each of the 2040 scenarios.

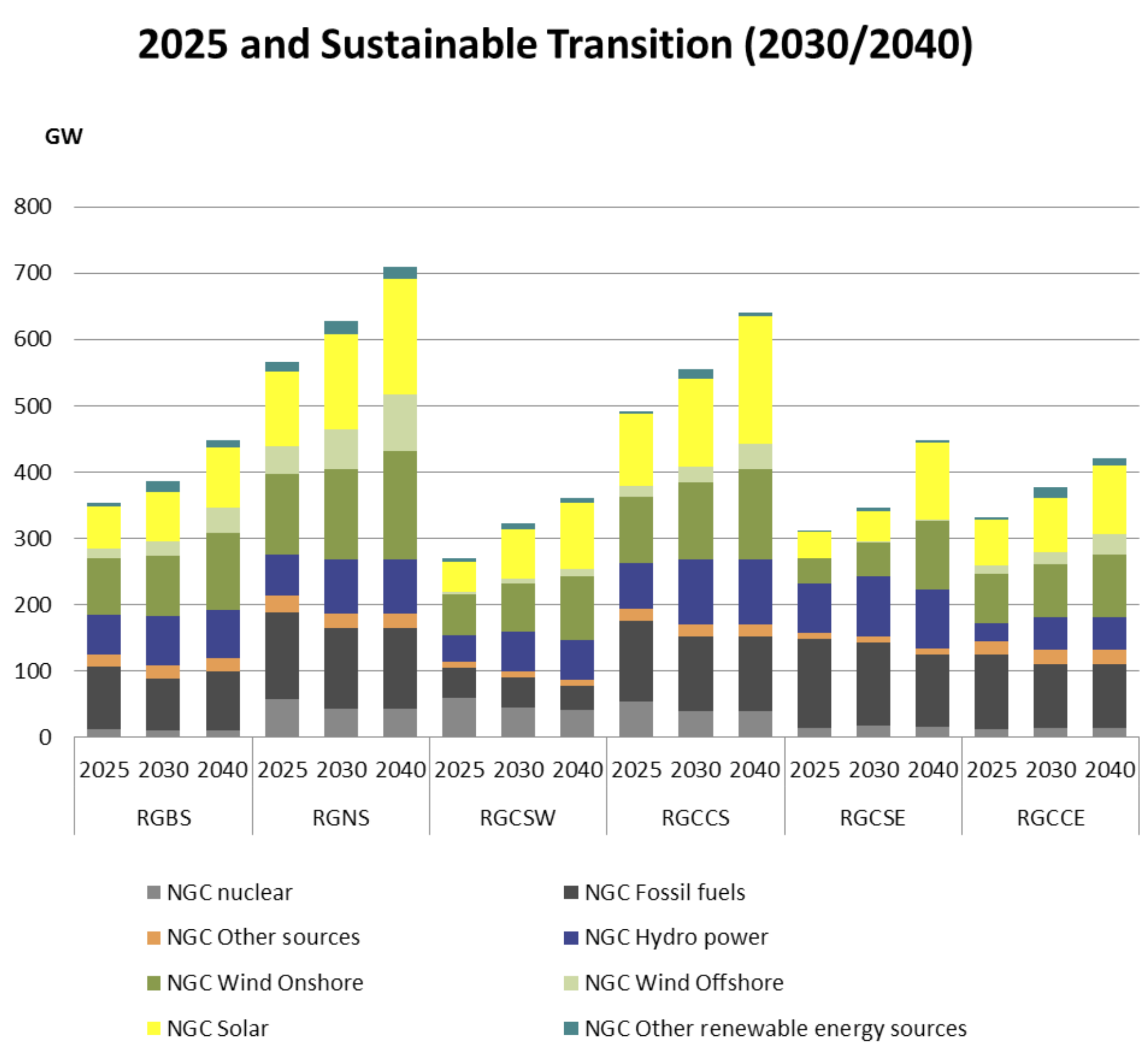
Figure 17: Standard costs used during the Identification of System Needs studies



1.4.2 Installed production capacities per regional group

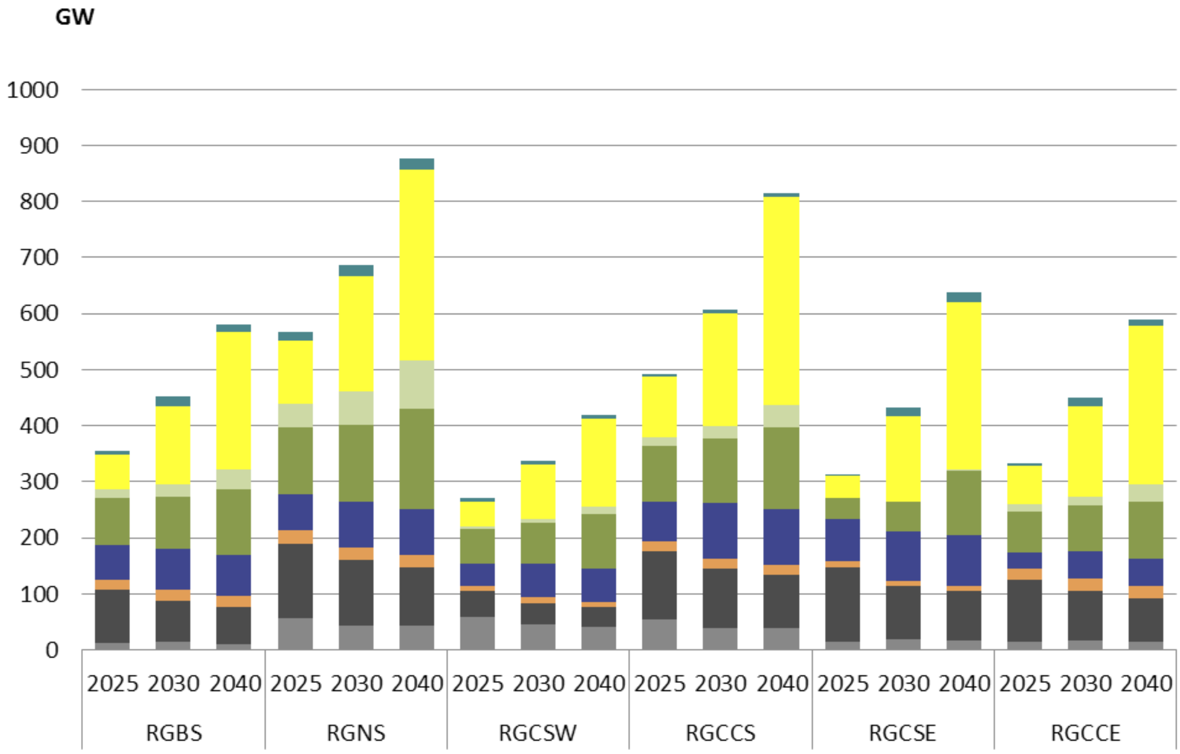
The three graphs in Figure 18 below show the installed production capacities for all six regional groups, three time horizons and scenarios.

Figure 18: Installed generation capacities per regional group

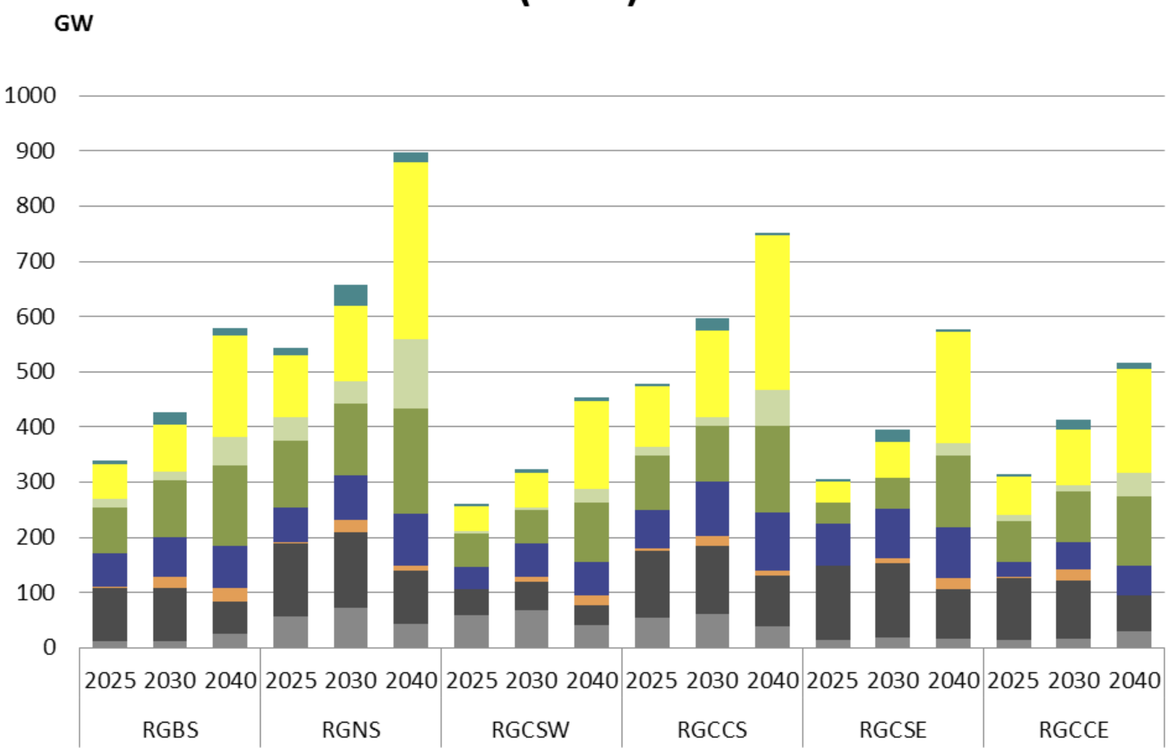


RGBS	–	Regional Group Baltic Sea
RGCCE	–	Regional Group Continental Central East
RGCCS	–	Regional Group Continental Central South
RGCSE	–	Regional Group Continental South East
RGCSW	–	Regional Group Continental South West
RGNS	–	Regional Group North Sea

2025 and Distributed Generation (2030/2040)



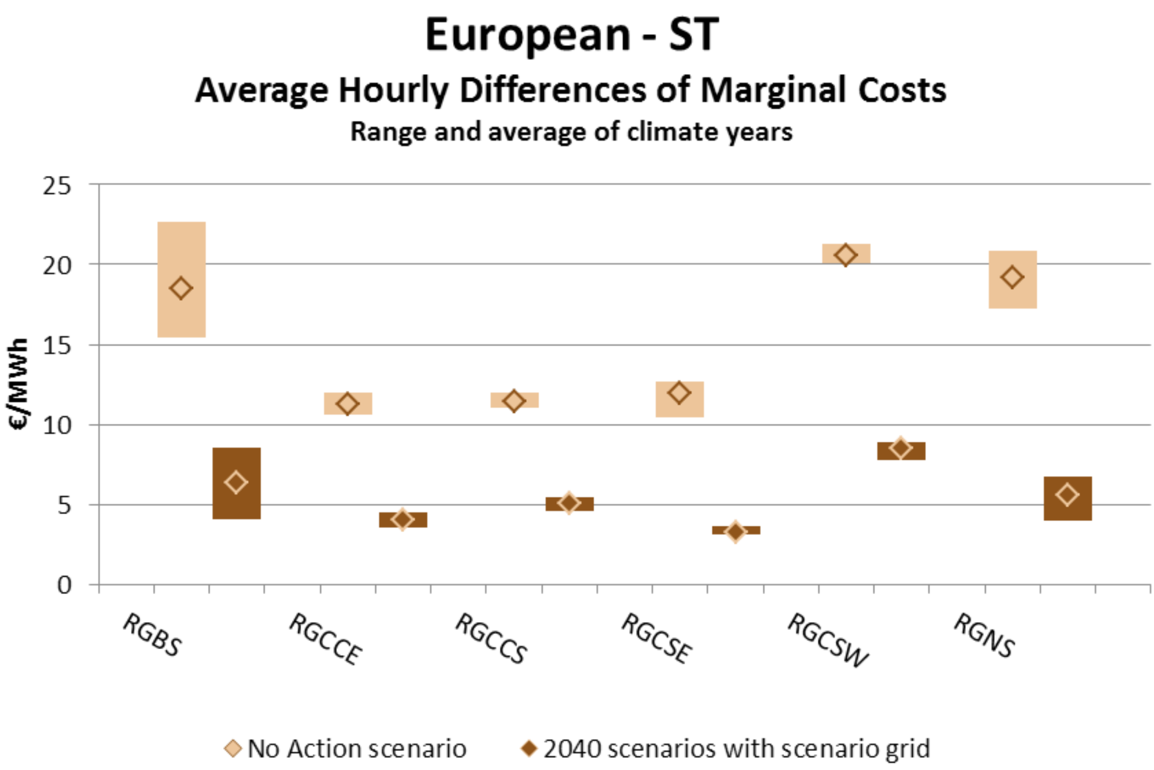
2025, EUCO (2030) and Global Climate Action (2040)

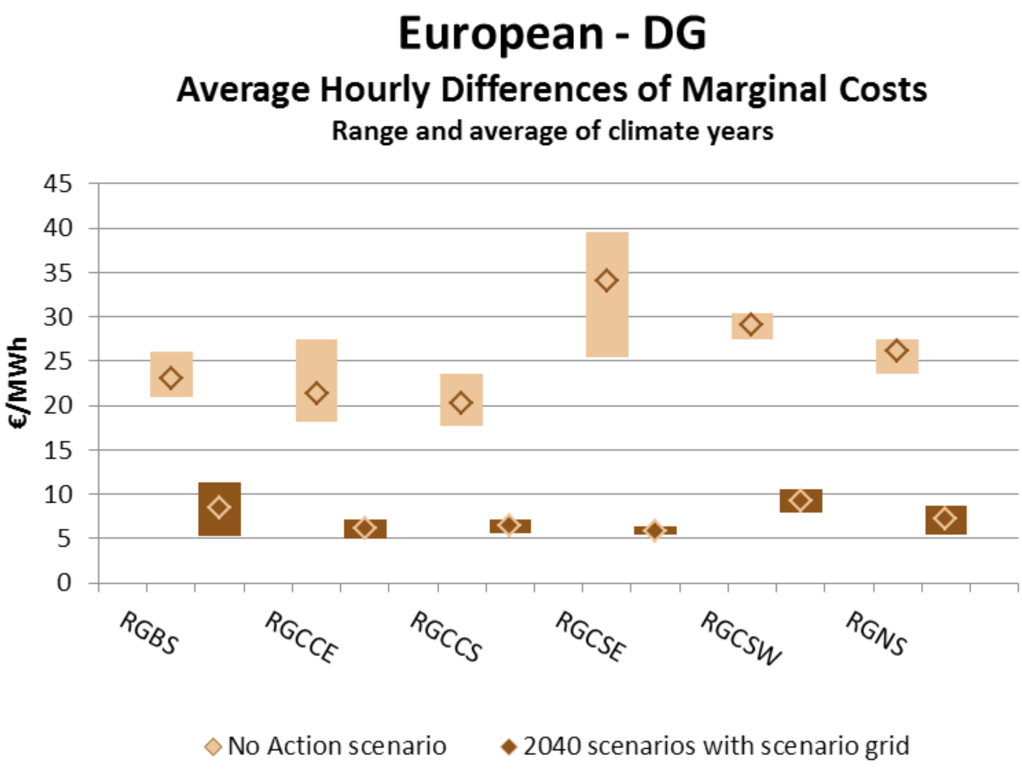


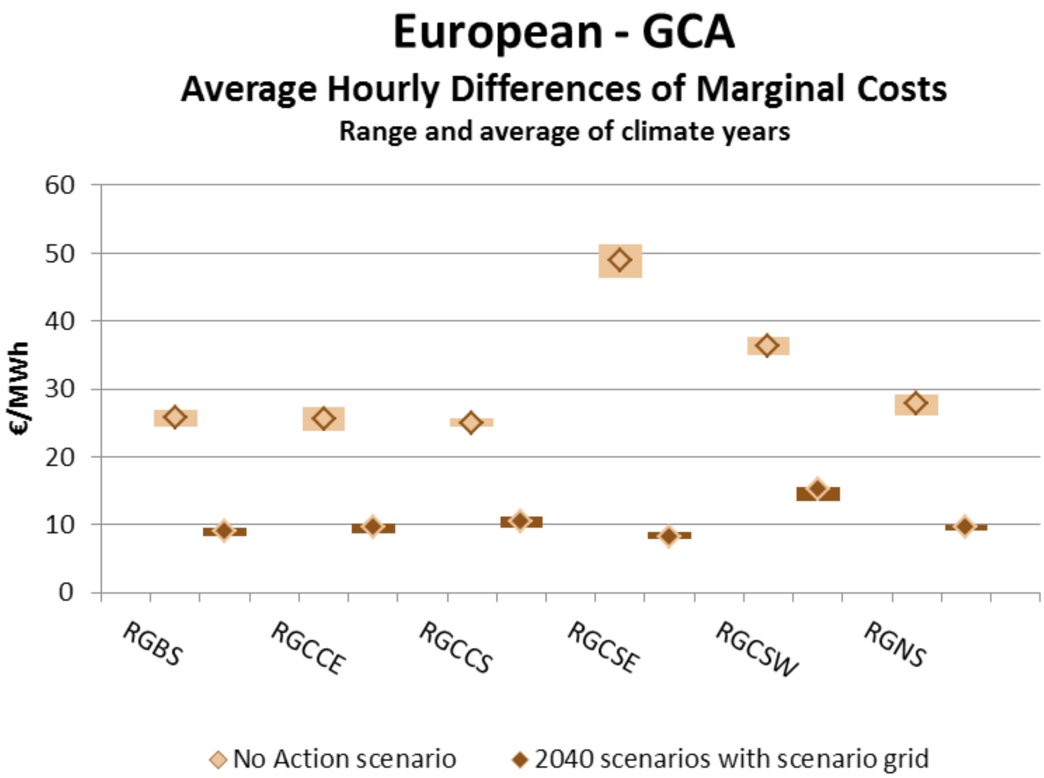
1.4.3 Additional market results

The charts below in Figure 19 show the ranges and average marginal cost differences on the borders of each regional group and for each of the 2040 scenarios.

Figure 19: Average hourly cross-border differences of marginal cost for electricity production

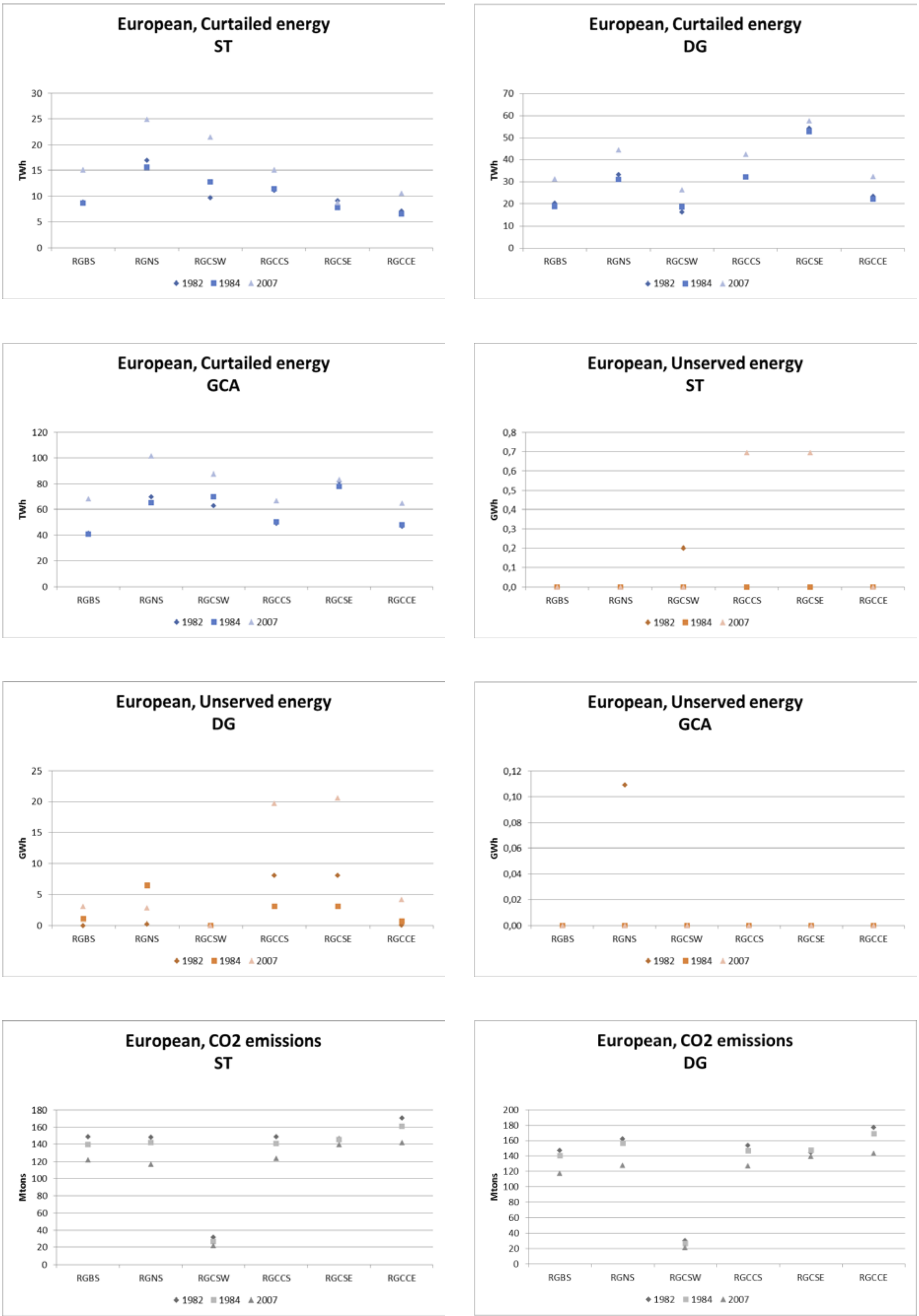


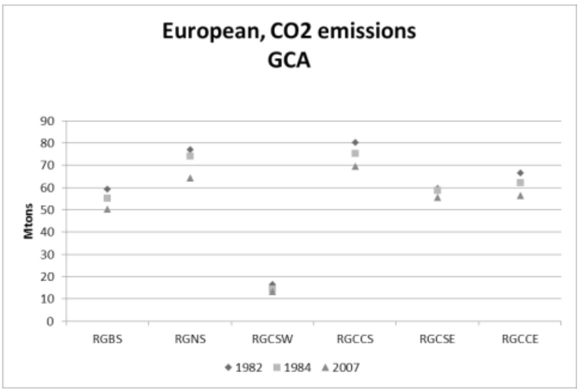


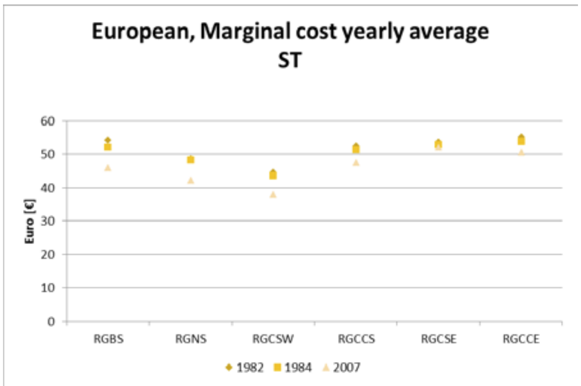

European - GCA
Average Hourly Differences of Marginal Costs
Range and average of climate years
€/MWh
60
50
40
30
20
10
0
RGBS
RGCCE
RGCCS
RGCSE
RGCSW
RGNS
No Action scenario
2040 scenarios with scenario grid

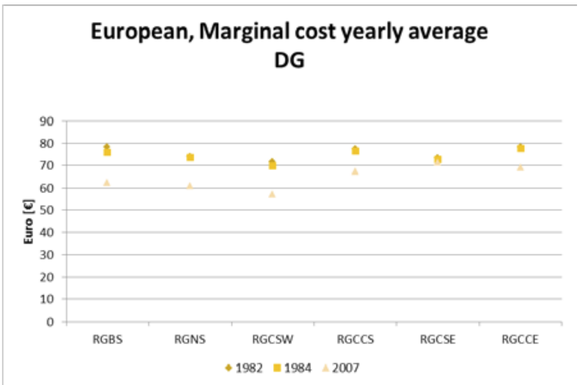
The charts in Figure 20 below show details about the impact of different scenarios and climate years on the curtailment of energy, the amount of unserved energy, the CO_2 emissions, the marginal costs and the annual net country balances.

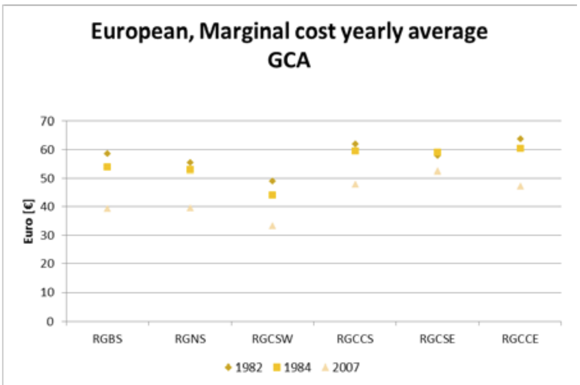
Figure 20: Amount of curtailed energy based on various climate years

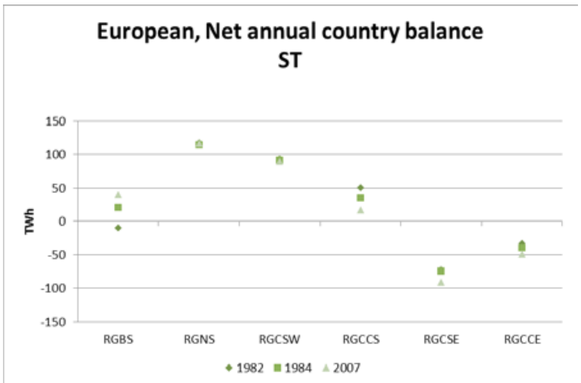


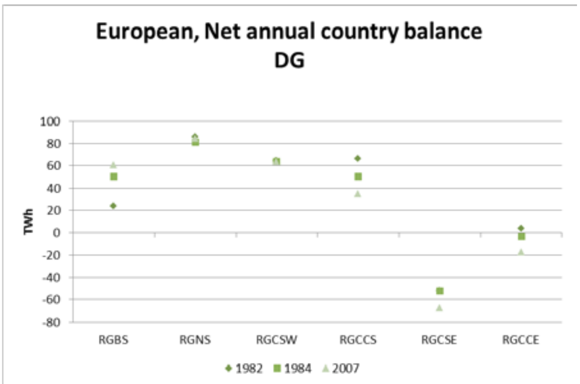

European, CO2 emissions
GCA
Mtons
RGBS
RGNS
RGCSW
RGCCS
RGCSE
RGCCE
1982
1984
2007

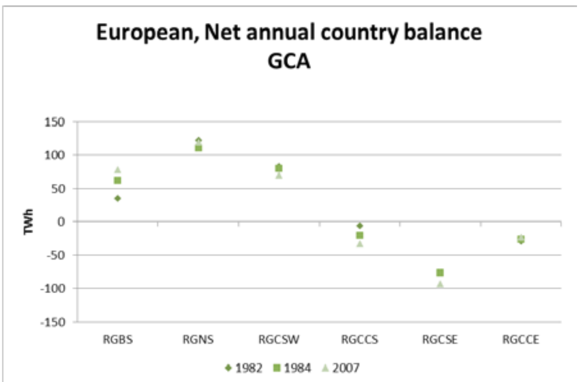

European, Marginal cost yearly average
ST
Euro [€]
RGBS
RGNS
RGCSW
RGCCS
RGCSE
RGCCE
1982
1984
2007


European, Marginal cost yearly average
DG
Euro [€]
RGBS
RGNS
RGCSW
RGCCS
RGCSE
RGCCE
1982
1984
2007


European, Marginal cost yearly average
GCA
Euro [€]
RGBS
RGNS
RGCSW
RGCCS
RGCSE
RGCCE
1982
1984
2007


European, Net annual country balance
ST
TWh
RGBS
RGNS
RGCSW
RGCCS
RGCSE
RGCCE
1982
1984
2007


European, Net annual country balance
DG
TWh
RGBS
RGNS
RGCSW
RGCCS
RGCSE
RGCCE
1982
1984
2007


European, Net annual country balance
GCA
TWh
RGBS
RGNS
RGCSW
RGCCS
RGCSE
RGCCE
1982
1984
2007

1.6

Choice of climate years

For the first time, the analyses performed in the TYNDP 2018 process have been developed in three different climate conditions selected in a climatic database of 34 different time series, provided with the cooperation of Météo-France and Technical University of Denmark.
The time series available for the years between 1984 and 2014, are related to:
— precipitation
— wind
— temperature
— sun exposition.

In order to select a limited number of climate conditions to be used in the analysis[10] the ENTSO's experts used the "k-means clustering" analysis. "k-means clustering" is a method of vector quantisation, originally from signal processing, that is popular for cluster analysis in data mining. The approach aims to partition n observations into k clusters in which each observation belongs to the cluster with the nearest mean, serving as a prototype of the cluster.

The method is based on an iterative algorithm that divides the data into k groups so that observations within a group are similar whilst observations between groups are different. After each iteration, a parameter, R2, is evaluated to indicate the proportion of the variance in the dependent variable that is predictable from the independent variable. The closer R2 is to 1, the more representative is the clustering.

In the present framework:
— n = number of climate years (34 in this case)
— k = target number of climate years.

The algorithm has been performed on four dimensions (load, wind, solar and hydro inflow) and considering different zones aggregation as reported in the following table:

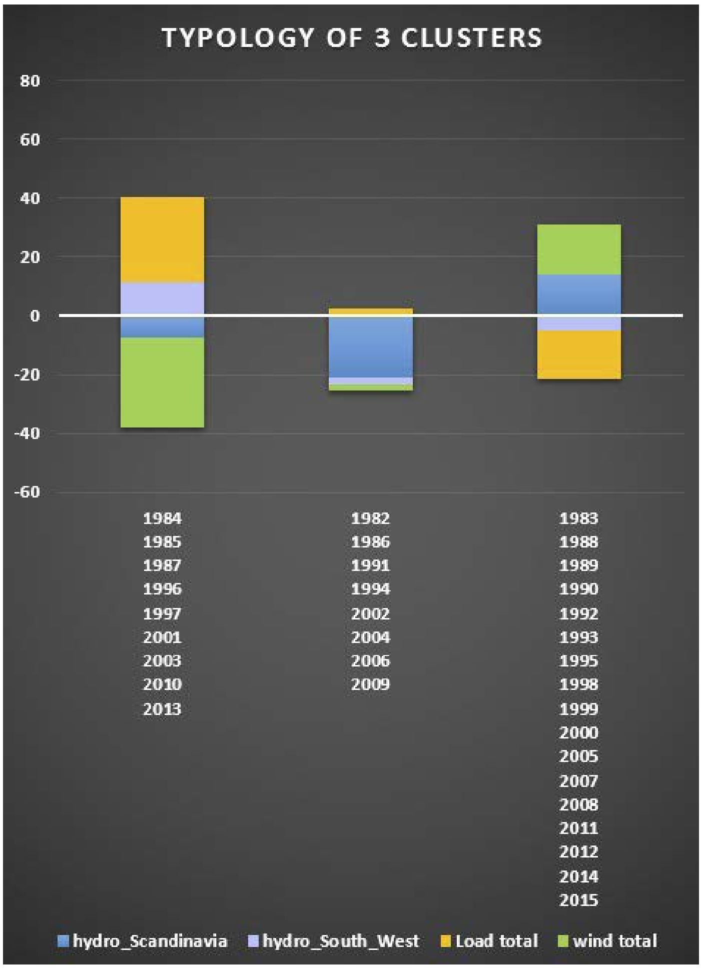
Macro region	Zones										
Scandinavia	DKe	DKkf	DKw	FI	NOm	NOn	NOs	SE1	SE2	SE3	SE4
Baltic countries	LV	EE	LT								
Central west 1 FR-BE-NL	BE	FR	NL								
Central west 2 DE-CH-AT-LU	DE	DEkf	AT	CH	LUb	LUf	LUg	LUv			
South west	ES	PT									
Central east	CZ	SK	HU	PL	RO						
GB+IE	GB	IE	NI								
South east	GR	CY	BG	MK	ME	MT	HR	SI	RS	AL	BA
South central	ITcn	ITc	ITn	ITs	ITsar	ITsic					

The input data are, for each year, and for each region: the difference between the value and the average of all years.

According to the data available and the feasibility of the workplan, three clusters have been considered at the end as reported in Figure 21 (R2 = 0,55). Inside the clusters the different years can be considered with the same representativity.

[10] T he need to limit the number of climate conditions was to guarantee the feasibility of the overall TYNDP 2018 process workplan.

Figure 21: Clusters of climate conditions based on the last 34 climate years



Each cluster will also be allocated a weight (number of years in the cluster) and a story line (e.g cold year with large inflows in Scandinavia, poor wind…)

1.7

Power to gas

Introduction

Power to gas (P2G) is the name for the technology and process that converts electrical power into a gaseous energy using electrolysis. It has the capability to increase system and sector coupling between electricity and gas, helping to manage the challenges that intermittent generation creates and offers a highly flexible means of renewable energy production and storage.

The hydrogen produced can be used directly and locally as a fuel in the transport sector, for industrial heat, as a chemical feedstock or converted back to power. Equally, the hydrogen can be stored or transported over long distances by using the gas networks, therefore enabling its use in any gas application connected to the grid. Investigations are currently ongoing into the hydrogen percentage that can be injected into these systems, but there is also the option to combine the hydrogen in a methanation process with sequestered CO_2, producing carbon neutral synthetic methane that can be used to any degree with the natural gas grids and make an important contribution to the energy transition.

Benefits

- seasonal storage of high density renewable energy
- indigenous supply source of an efficient long-distance energy carrier
- can make use of existing gas transmission, distribution and storage infrastructure
- offers a route to decarbonise difficult sectors
- reduces curtailed renewable energy and creates a valuable product from low/negative cost electricity
- electricity balancing/auxiliary services
- use of CO_2 in the methanation process, could be combined in future with CCS of some processes to create negative emissions.

Projects, current technology and future developments

P2G is a proven technical concept that utilises existing electrolysis methods, typically either an Alkaline or Polymer Electrolyte Membrane (PEM) electrolyser. There are a number of projects operating within the EU (http://www.europeanpowertogas.com/demonstrations), that are studying the application of the technology and its potential on a mass commercial scale.

As well as the expected operational and economic improvements in commercially available Alkaline or PEM technology, Solid Oxide Electrolyser Cell (SOEC) technology is also being developed which offers increased efficiency from high-temperature electrolysis[11]. In addition to this, different methanation processes are also being studied further (https://www.storeandgo.info/about-the-project/).

Future requirements

Currently, P2G implementation is at a pilot stage, with large commercial scale development not considered economically viable. High CAPEX costs associated with large electrolysers, current fuel, electricity and CO_2 prices all contribute to this to some degree. The development of electricity and gas markets, climate targets, fuel and CO_2 prices and technology will all have an impact on the economic viability of P2G in the future.

However, whilst there are many unknowns, the increase of variable renewable installed capacities are expected to continue in the EU. This will lead to the increased challenges of balancing the system, further energy curtailment and more hours of low or negative marginal priced electricity[12]. P2G can be a solution for these issues as well as contributing to the decarbonisation of the EU energy system, by providing renewable energy for difficult to electrify sectors.

In the short term, in order to see increased development and uptake, elements such as green gas certificates/CO_2 certificates and balancing services may need to be factored in. Equally, on a European scale, P2G could reduce the need for expansion and upgrade of the electricity distribution networks, and may in some cases. This will save expenditure by utilising existing infrastructure, which could be supported by policies or regulation.

[11] HELMETH Project (Integrated High-Temperature ELectrolysis and METHanation for Effective Power to Gas Conversion) aims to demonstrate the technical feasibility of a conversion efficiency > 85 % from renewable electricity to methane.
[12] Including TYNDP 2018 price and CO_2 assumptions = GCA 2040 P2G cheaper than natural gas when produced from <€36/MWh.

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