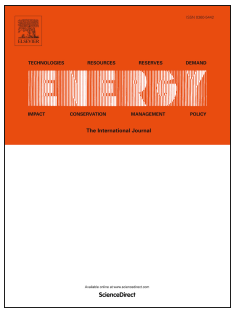
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Adding Value to EU Energy Policy Analysis Using a Multi-Model Approach With an EU-28 Electricity Dispatch Model

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Abstract

The European Council has agreed ambitious EU climate and energy targets for 2030, including a 40% reduction in greenhouse gas emissions compared to 1990 levels and a minimum share of 27% renewable energy consumption. This paper investigates the challenges faced by the European power systems as the EU transitions towards a low carbon energy system with increased amounts of variable renewable electricity generation. The research here adds value to, and complements the power systems results of the PRIMES energy systems model that is used to inform EU energy and climate policy. The methodology uses a soft-linking approach that scrutinizes the power system in high temporal and technical detail for a target year. This enables generation of additional results that provide new insights not possible using a single model approach. These results point to: 1) overestimation of variable renewable generation by 2.4% 2) curtailment in excess of 11% in isolated member states 3) EU interconnector congestion average of 24% 4) reduced wholesale electricity pricing and few run hours raising concerns for the financial remuneration of conventional generation 5) maintenance of sufficient levels of system inertia in member states becomes challenging with significant penetrations of variable renewable generation.

Highlights

- Develops a multi-model framework to quantify impacts of increased RES-E in the EU
- Builds an EU-28 PLEXOS power systems model with high technical & temporal resolution
- Quantifies interconnector congestion, electricity curtailment and wholesale electricity prices
- Identifies concerns for conventional generation in an energy only market

Keywords

Energy systems modelling; Power systems modelling; Soft-linking; Renewable energy

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1. Introduction

The European Council agreed in November 2014 [1] ambitious targets for energy and climate change mitigation for 2030, namely to achieve i) a 40% reduction in greenhouse gas (GHG) relative to 1990 levels, ii) a 27% share of energy use from renewable sources and iii) a 27% improvement in energy efficiency. Energy system modelling is used to project technology pathways that meet these targets and is a crucial part of long term energy planning. Energy systems models determine optimal pathways for this transition by selecting technologies that maximise emissions reduction with lowest risk both technically and financially. Such ambition regarding European emissions reduction imply an expected high penetration of variable renewable electricity generation in future [2]. However, from an engineering perspective, such technologies pose a number of challenges relating to the adequacy and reliability of the power system at high penetrations. Long term energy system models have a wide sectoral focus and detailed modelling is required to ensure a reliable power system to properly assess the integration challenges that high penetrations of variable renewables bring. To achieve the significant emissions reductions required, long term planning must also consider the potential benefits of a variety of factors such as flexibility measures in combination with better integration between the electricity sector and various other sectors of the economy such as thermal & transport sectors which has been shown to enable penetrations of variable renewable generation in excess of 80% in the electricity sector [3].

The primary software model used to inform EU climate and energy policy is PRIMES, a partial equilibrium model of the European Union energy system developed by the National Technical University in Athens [4-7] for scenario analysis and policy impact studies. The model was used to assess the impacts of EU GHG mission reduction scenarios for the period to 2030 that in turn informed the European Council's decision [2]. The impact assessment considered different levels of ambition relative to a *Reference scenario* (PRIMES-REF), i.e. a scenario exploring the consequences of current trends including full implementation of policies adopted by late spring 2012 in the European Union. The impacts of different levels of GHG emissions reduction, renewable energy penetrations and energy efficiency ambitions were assessed relative to PRIMES-REF. PRIME-REF assumes that the EU will meet the target (under Directive 2009/EC/28) for a 20% share of renewable energy penetration by 2020; the target of 20% GHG emissions reduction by 2020 relative to 1990 levels (under Directive 2008/EC/29 for ETS emissions and Decision 406/2009/EC for non-ETS emissions) and that the Energy Efficiency Directive (Directive 2012/EC/27) will be fully implemented. In addition PRIMES-REF includes assumptions that all other policy goals legislated for prior to Spring 2012 (including for example the regulation on car manufacturers regarding light duty vehicles (Regulation 403/2009/EC) will also deliver anticipated targets. The PRIMES-REF scenario extends to the year 2050 and the results indicate that by 2030 the EU can achieve GHG emissions reductions of 32% below 1990 levels; 24% penetration of renewable energy and 21% energy efficiency gains.

Long term energy system planning decisions are commonly underpinned by analyses using long term energy systems models, as is the case with PRIMES for the EU. However, in terms of the power sector such models can encounter difficulties in assessing the challenges associated with a low carbon transition [8]. This work addresses a gap in long term planning by operationally analysing, under high technical and temporal resolution modelling, the realisation of ambitious carbon reduction policy for the European power sector. This provides insights that are not directly possible in long term models such as PRIMES, as in direct quantification of interconnector congestion, electricity curtailment and market pricing. The quantification of these and other elements allows for better assessment of the difficulty of integrating significant shares of renewable generation. This work also allows closer study of challenges they create for conventional generation which can be

heavily impacted by reduced market pricing and reduced capacity factors due to the merit order effect displacing them in the generation stack.

The difficulty energy systems models have in sufficiently accounting for operational dynamics of the power sector owe largely to the breadth of their focus, which span many sectors of the economy, in which the power sector is typically represented in a stylised way with a limited number of time slices to make the models computationally manageable. Low levels of detail in the modelling of the power sector can lead to an overestimation of the value of baseload technologies and variable renewable generation, while the value of flexible generation technologies with higher generation costs can be underestimated [9]. On the other hand, crude representations of integration challenges such as upper limits on variable renewable generation can lead to an overestimation of the cost of meeting emissions reduction targets [10]. A number of methodologies have been developed to improve the representation of challenges associated with a low carbon transition of the power sector in such long term models [9-12].

This paper builds on previous literature by applying a multi-model approach [13] using results from the PRIMES model to construct a 28 Member State power system model. In previous work, multi model approaches were used to analyse results for the Irish TIMES model and the Italian MONET model, where valuable insights were gained in terms of the increased need for flexibility (so as to ensure the portfolio outputted is capable of meeting power demand with an increased variability of power production) and careful incentivisation of investment to promote adequate capacity expansion plans in a low carbon future for electricity [13-15]. Other work using the OSeMOSYS modelling framework, as in [16], use a multi model approach and highlight how such an approach can lead to a better assessment of costs and how many long term models can underestimate the costs of meeting long term emissions reduction targets. Increased technical and temporal of modelling allows detailed assessment of the output of these models.

The heating and cooling strategy issued by the European Commission advocates increased synergies between sectors via district heating and cooling, smart buildings and cogeneration of heat and power to reduce the cost of the energy system [17]. An additional scenario was simulated to determine the impact of demand response in the power system model simulation, though this does not capture important sectoral interactions that would be critical to its implementation. Previous work has included analysis of this sectoral integration using other models to compensate for similar PRIMES scenarios [3, 18, 19]. However, these analyses do not account for the significant impact of interconnector flows between Member States and their application thus generated different insights. It is therefore apparent that the various analyses and models supplement one another and make way for a more holistic view of how best to decarbonise the European energy system.

This work considers the results of the publicly available 2013 PRIMES-REF for the year 2030, and uses them as a starting point for further analysis, with a particular focus on the results for the power system. PRIMES REF includes full implementation of current EU policies that were adopted by spring 2012 and does not represent potential avenues for policy development that have been proposed since that time such as those proposed in latest European Commission winter energy package [20]. This work uses these PRIMES-REF results to build and run a unit commitment & economic dispatch model using PLEXOS® Integrated Energy Model (hereafter referred to as the UCED scenario model). This enables additional analysis to be carried out using the added value that a power systems model with higher temporal resolution and technical detail can bring, namely to quantify at Member State level levels of curtailment of variable renewable electricity, interconnector congestion and wholesale electricity prices. This approach also allows for the analysis of the operational impacts of

demand response and those of the maintenance of sufficient levels of grid inertia which are required for frequency stability.

While power system models and energy systems models both model electrical power systems they are profoundly different modelling tools regarding their practical aim. Dedicated power system models typically focus solely on the electricity system with significantly higher technical and temporal resolution. The primary inputs to power systems models can consist of electrical load, fuel prices and the technical attributes of power plants and transmission systems. Whole energy systems models by contrast, model electrical generation endogenously and are driven by the combined behaviour of end use sectors (that are driven by exogenous energy service demands) and by the supply sectors that deliver primary fuels. The focus of an energy systems model is to provide a technologically rich basis for determining energy pathways over a variety of time horizons from the medium-term (Up to 30 years) to long-term (Between 50 and 100 years). Power system models on the other hand have typically much shorter time horizons. Due to the dedicated problem focus of these models on the power sector, the sector can be examined at significantly higher resolution in comparison to energy system models which deal with a much wider set of problems which makes them complementary to each other [13]. The problem in the power system model in this work, is focused on the dispatch of power generation at least cost to meet an electrical demand but all the while obeying the technical constraints and capabilities of the power system. This problem is often referred to as Unit Commitment and Economic Dispatch problem and these models typically have a time horizon of one year. Such power system models can also be used for analysing shorter term power system dynamics or indeed long term capacity expansion planning. A variety of models are used for power system studies and are detailed in [21].

The purpose of the paper is to enhance and to check the robustness of the results for electricity generation of the PRIMES-REF scenario for the year 2030. It does this by using the PRIMES-REF results to build a UCED scenario model. It then utilises the increased technical and temporal resolution of the dedicated power systems model to scrutinise the PRIMES-REF results for the year 2030. The UCED scenario model adds value by generating new results with PLEXOS® that provide new insights to the results from PRIMES. In particular, the power system model quantifies i) variable renewable electricity curtailment; ii) levels of interconnector congestion and iii) wholesale electricity prices.

In the UCED scenario model, the power system is modelled in detail at Member State level, the model runs at hourly resolution for the full target year of 2030 whereas PRIMES uses a maximum of up to 9 typical days at hourly resolution in the extended model version [22]. The power system model uses individual hourly electricity generation profiles for solar and wind power for each Member State based on local conditions and capacities for the year 2030, predicted electricity hourly demand profiles for the year 2030 and generation profiles for all other methods of electricity generation outlined in PRIMES (Hydro, Solids Fired, Oil Fired, Gas Fired, Biomass waste etc.) The model also considers the levels of interconnection between Member States, demand response and the maintenance of sufficient levels of grid inertia across the European Union.

To give context on the level of ambition regarding PRIMES REF in terms of renewable electricity generation, particularly variable renewable electricity generation, Table 1 was constructed. Power system issues associated with variability are well documented by the IEA [23, 24]. Variability poses a number of challenges for power systems particularly in the areas of system balancing, unit commitment and economic dispatch. This variability leads to the increased flexibility being required in the generation mix for system balancing. Flexibility measures such as demand response [25, 26], power to gas [27, 28], power to heat[29, 30], CAES [31], thermal storage [32], pumped hydro

storages [33, 34] and increased power plant flexibility [35] will be critical in the integration of significant portions of variable renewable power [36]. European energy policy development must ensure conditions are favourable for investment in this area, drawing all flexible resources regarding generation, demand and storage, into the market through use of proper incentives and a market framework better adapted to them [37].

Increasing penetrations of variable renewable power have been show to impact the frequency, voltage, transient and small signal stability of the power system, a review of these impacts is found in [38]. High penetrations of non-synchronous modes of generation such as wind and solar photovoltaic alter the response of the power system for faults and contingencies by reducing the on-line system inertia [39, 40]. This in turn raises concerns regarding the maintenance of power system reliability at high penetrations of such modes of generation. It is the non-synchronous nature of variable renewable generation such as wind and solar photovoltaic sources that means they do not currently contribute to grid inertia (although this is an active area of research [41, 42]). Grid inertia refers to the stored rotational energy on the system required to mitigate frequency fluctuation and to limit the rate of change of frequency (RoCoF) in the event of a sudden generator outage or failure of critical electrical infrastructure [43]. Inertia may be a cause for concern for certain Member States in future and is currently of particular concern to relatively small isolated power systems such as Ireland [44].

Table 1 details the percentage contribution of renewable electricity (RES-E) and variable renewable electricity (VRES-E) generation by member state in terms of gross electricity generation for the year 2014 [45], and for 2030 according to the PRIMES REF scenario. VRES-E is defined as wind and solar electricity production. The values at EU level are also shown, along with the values for the PRIMES GHG40 scenario. The PRIMES GHG40 Scenario is a scenario run of PRIMES in which the level of ambition extends beyond that of the 2030 PRIMES REF scenario, in 2030 it attains a 40% GHG reduction and by 2050 an 80% GHG reduction compared to 1990 levels. It is set with enabling conditions that are modelled by altering modelling parameters with respect to those included in the Reference conditions. The enabling conditions are assumptions that act independently of carbon prices/values or economic or regulatory incentives for renewables and energy efficiency [2].

<Table 1>

The difference between 2014 and PRIMES REF 2030 are very considerable, most notably from an operational standpoint in terms of VRES-E penetration. However, the difference between PRIMES REF and PRIMES GHG40 scenario results for 2030 are not significant with a difference of RES-E and VRES-E penetrations of 4.8 percentage points and 3.5 percentage points respectively. This small difference in penetration of RES-E and VRES-E enable the results of this work to be considered a proxy for broadly assessing penetration rates that that would be achieved under the more ambitious 2030 PRIMES GHG40 scenario, providing insights regarding the challenges associated with significant penetrations of variable renewable generation. In addition the difference in ETS price between 2014 levels (€6/tonne CO_2) and PRIMES REF (€35/tonne CO_2) is significantly higher than the difference between 2030 PRIMES REF and 2030 PRIMES GHG40 (€40/tonne CO_2).

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2. Modelling Tools

2.1. PLEXOS® Integrated Energy Model:

PLEXOS® is a tool used for power systems modelling[1] [46]. It is a commercial modelling tool used for the planning of power systems and simulation of electricity markets. It has also been used in many academic applications for non-commercial research and it is free of charge for such work. In this paper, the focus is on the least cost unit commitment and economic dispatch of the electricity system, with a focus on a single year (2030).

The setup of the model is focused on the minimisation of overall system operation cost. This minimisation is subject to constraints relating to the dispatch of electricity such as operational attributes of generators, availability of generators, system operation and transmission constraints and fuel & emissions costs. Models can be solved through use of linear or mixed integer linear programming. This work used rounded linear relaxation which enabled faster solution times than full integer optimal solutions because it made use of a limited number of passes of linear programming which is less computationally intensive than integer programming while maintaining significant precision. In PLEXOS, the mathematical formulations behind the model are openly available for inspection, making it transparent. In this work, the model was run using XPRESS-MP provided by FICO to solve the model [47].

In power system operation, many renewables such a power generation from wind and solar operate by effectively bidding at zero for each dispatch period due to their lack of fuel costs. The very nature of these modes of generation significantly differ to conventional generators and raise new challenges regarding to power system operation such as increased ramping requiring and reduced market pricing to name but a few. These challenges are largely due to the inherent variability, non-dispatchability and non-synchronous nature of these modes of generation.

Given the large amount of renewable electricity generation expected to come online to meet the ambitious targets in the EU (even in the PRIMES-REF scenario), accurate modelling of these variable renewable resources is very important and merits strong consideration in policy development. The increasing amount of variable renewables anticipated in the EU-28 in order to meet ambitious renewable energy targets means that the modelling of this variability from an operation standpoint is of paramount importance.

The operational simulation of the realisation of such ambition, in the context of unit commitment and economic dispatch, enables detailed assessment of the challenges associated with a transitional low carbon electricity sector.

2.2. PRIMES Energy System Model

The PRIMES Energy System Model is a model of the European Union energy system. It is partial equilibrium model that is the result of a number of collaborative projects supported by the Joule programme of the Directorate General for Research of the European Commission. The model focus is on the medium to long term time horizon and it is used for a variety of tasks including forecasting, scenario analysis and policy impact studies. PRIMES is modular in nature and allows for use of a united full model or indeed partial use of some of its modules to support specific studies. It is a behavioural model that also explicitly captures the demand, supply and pollution abatement technologies relating to energy use [22].

[1] PLEXOS can also model integrated energy systems, combining water, gas and electricity systems modelling

Because PRIMES is a partial equilibrium model, the model results form a partial equilibrium solution. This means that supply and demand of energy attain an equilibrium in every scenario but model feedback is not provided to the rest of the economy for alternative pathways for the energy system that is generated in each scenario

Error! Reference source not found. illustrates the PRIMES model structure, including the inputs to the model and the different scenarios generated. PRIMES-REF is the EU Reference Scenario, which describes the impacts of current trends which include full implementation of current European policy that were adopted by spring 2012. The PRIMES-REF gives an indication of the anticipated developments with regard to policies that have been agreed out to the year 2050. PRIMES-REF allows for the assessment of the effect of current policies and how they relate to achieving long term goals, serving as a comparison for other policy scenarios with varying levels of ambition regarding reduction of emissions, development of renewable energy and energy efficiency.

<Figure 1>

The technology attributes used in the PRIMES model are exogenous with both supply & demand side technologies considered. These technology attributes are reflected by parameters that are based on a variety of up to date reliable sources such as studies, expert judgement and existing databases [48].

To account for future technological development certain assumptions are made for anticipated future development of technologies over the model run. For example, in the model, design regulations cause a reduction in cost of energy efficient devices and improved CO_2 standards for vehicles facilitate increased uptake of more efficient fossil fuelled vehicles and decent penetrations of electric vehicles. Other assumptions are made about the cost developments of technologies, such as reduced costs for wind and solar-photovoltaic generation but increased costs for nuclear generation following the nuclear disaster at Fukishima. Carbon capture and storage (CCS) is not anticipated in PRIMES to become commercially viable until after 2030 and even at that time for it to be deployed it will be reliant on the cost of carbon. These assumptions and others are further are detailed in [22].

Below is a graphic illustrating the generation mix by Member State as in the Reference Scenario Results for 2030:

<Figure 2>

3. Comparison of models

Both PRIMES and PLEXOS models differ in focus and thus differ in representation of temporal and technical elements of the power sector. To properly compare both models, table 2 is presented which details the differences between both models in the context of this work.

<Table 2>

Table 2 provides context for the work at hand, by which value is added to large energy system model results through use of the dedicated power system model.

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4. Methodology

4.1. Modelling Approach

The modelling approach used in this paper is a soft-linking approach presented in Figure 3. This approach builds on approaches followed in previous papers [13] and [15] by applying it to a 28 Member State multi-regional model. It uses highly detailed unit commitment and dispatch modelling of the electrical power system, derived from the energy system model results, to gain insights into its operational realisation and thus aid long term planning energy system planning.

<Figure 3>

In PRIMES REF, results for the installed power generation capacities for each Member State are broken down into various modes of generation such as Hydro, Solids Fired, Oil Fired, Gas Fired, Biomass waste etc. The results issued from PRIMES are aggregate figures; therefore a challenge to the model's construction surrounded the disaggregation of these generation capacities. Deane et al highlighted that the development of national renewable energy action plans in individual countries can neglect the significant effects that cross border power flows have on market dynamics especially in the presence of geographically dispersed variable renewable generation sources such as wind and solar [49]. Aggregate generator portfolios were thus developed using standard generators with standard characteristics (max capacity, min stable factors, ramp rates, min up & down times, maintenance rates, forced outage rates, start costs etc), as opposed to developing portfolios as projected by individual Transmission System Operators, so to avoid model bias. A selection of these characteristics can be seen in Table 3 for thermal generators. Each disaggregated generation capacity was made up by numerous identical generators summing to the total capacity as split by fuel type in the PRIMES reference scenario results. For natural gas fired generation 10% of installed capacity was allocated as Open Cycle (OCGT) to reflect and capture the flexibility of these less efficient plants on the power system with the remainder of natural gas fired plants being modelled as Combined Cycle units (CCGT). Heat rates for the various types of power plant are defined on a Member State by Member State basis, in the PRIMES-REF scenario results.

<Table 3>

4.2. Interconnection

Net transfer capacities are limited for this work to Interconnection between Member States and no interregional transmission is considered below Member State level. The electricity network expansion is aligned with the latest 10 Year Development Plan from ENTSO-E, without making any judgement on the likelihood of certain projects materialising [50].

<Figure 4>

4.3. Fuel and Carbon Pricing

Fuel prices used are from [2] and are consistent across scenarios for each year and are shown in the Table 4 in terms of €2010 per barrel of oil equivalent (BOE). The CO_2 price used was €35 per Tonne (€2010).[2]

<Table 4>

[2] An additional scenario with a CO_2 price of €40/tonne was also generated to compare with the PRIMES GHG40 scenario but the changes in simulation results were not significant.

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4.4. Demand

The results of the PRIMES model detail overall electrical demand at an annual level only and includes demand from all sectors of the economy and electric vehicles (Electric vehicles are 3.4% of all electricity demand and 2.6% of energy in transport under PRIMES REF conditions). The power system model constructed is at an hourly resolution, and for this reason needed an hourly electrical demand profile. This was done through using historic electricity demand profiles from ENTSOE [51] for the EU28 in the year 2012 and scaling them to 2030 overall demand detailed in the PRIMES results by utilising an algorithm based on quadratic optimization with a peak scaling of 1.1.

4.5. Wind Generation

Localised hourly wind profiles for each Member State of the EU28 were used within the model. Physical wind speeds at an 80m hub height we gathered for multiple locations in each of the 28 Member States through use of MERRA data [52]. The multi turbine approach developed by Nørdgaard et al was used to account for the multi turbine and geographic spread nature of wind generation [53].

4.5. Solar Generation

Localised hourly solar profiles for each Member State of the EU28 were created and used within the model. This was done through use of NREL's PVWatts® Calculator web application which determines the electricity production of photovoltaic systems based on a number of inputs regarding the system location and basic system design parameters [54]. The profiles created were then normalised with the generation capacity for each Member State as in the PRIMES-REF 2030 results.

4.6. Hydro Generation

Hydro generation is modelled as individual Member State monthly constraints via generation profiles provided by ENTSOE for each individual Member State of the EU28 and Norway. These monthly constraints are decomposed to weekly and then hourly profiles in the optimisation process.

4.7. Demand Response

Demand response was implemented by allowing 10% of peak demand in each Member State be shifted to optimise system performance at least cost over the course of the day.

4.8. Inertia

For this analysis, minimum levels of inertia were maintained above a certain level so as to limit the RoCoF to 0.75Hz/s on each synchronous grid in the European region (i.e. the Grids of Ireland (SEM), Great Britain (National Grid), the Baltic states, Nordic states (NORDEL) and the Central European grid (UCTE)). The grids of Malta and Cyprus were omitted for this constraint as for such small systems such a constraint isn't as reasonably practicable. In the model the inertia constraint is simulated by assigning levels of inertia to each individual generator based on levels from literature [55] and assigning minimum static levels of inertia be required on grid to mitigate the outage of the of the largest infeed in each system within the model as under the N-1 Criterion as exemplified by [56]. The N-1 outage and corresponding minimum required inertia level used within this analysis for each region considered is displayed in table 5.The impact of imposing these minimum levels of inertia is examined identifying the inertia related challenges faced by certain regional grids in incorporating large shares of variable renewable generation.

<Table 5>

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Upon completion the PRIMES 2030 EU 28 Model consisted of over 2,200 generators, 22 Pumped Hydro Electrical Storage Units and 64 Interconnector Lines running at hourly resolution for the year 2030.

5. Results

This section presents and discusses a selection of results under a series of headings outlining the primary insights gained from this analysis. The main outputs are extracted and analysed with a particular focus on the impact of variable renewables on the operation of the European power system.

5.1. Wholesale Energy Prices

The wholesale energy price (electricity market price) here is derived based on the average hourly system marginal cost in each Member State over the course of the simulation based on the merit order. Scarcity pricing was used in the model but filtered out in the determination of regional wholesale energy prices. Uplift was enabled in the determination of pricing to ensure generators recovered fixed costs, this did not affect the optimal dispatch. However, this makes them not directly comparable to today's wholesale energy pricing. The prices reflected in the results of this work are higher than today's levels because of this uplift coupled with higher CO2 and gas prices. As such these market prices reflect the true operation cost associated with achieving a reliable low carbon electricity system for Europe. The high penetration of variable renewable generation sources contributes to containing and even lowering the wholesale prices of electricity based on short run marginal cost alone by causing a shift in the merit order curve and substituting part of the generation of conventional thermal plants, which have higher marginal production costs.

<Figure 5>

The wholesale energy price by Member State can be seen in figure 5. This figure was generated for the year 2030 power system under the reference scenario results as simulated in the model constructed. These prices provide an insight into the effect of achieving renewable energy targets through use of a high proportion of variable renewable generation. A number of Member States can be seen to have the low wholesale energy prices, especially Ireland with a price of 84 €/MWh. In Ireland's case, this is directly attributable the high proportion of variable generation which is planned to be installed and presents concerns. This has a strong seasonal impact and tends to reduce prices in the winter months when wind speeds are high and demand is also highest. This reduces the need for higher marginal cost generators to meet peak demand and long term affects the revenue base of conventional thermal power generation.

Within the power sector in Europe today, current market prices are not sufficient to cover the fixed costs of all plants operating on the system, a situation that is expected to become more critical in particular due to the current overcapacity induced by the economic slowdown in recent years and the penetration of renewables, which predominantly have fixed costs [57]. The low capacity factors for natural gas fired plant, particularly in 2030 as can be seen in red (below 30% capacity factor) in figure 6, suggest that natural gas fired plant may struggle to achieve sufficient financial remuneration in an energy only market in some Member States.

<Figure 6>

Figure 7 identifies the differences in capacity factors for Natural Gas generation between the 2030 PRIMES Reference scenario results and the results of the UCED scenario model. Greater resolution

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modelling of the PRIMES results enables. It is clear that the capacity factors differ substantially across the EU-28 between both models, at an average absolute difference of 18%.

<Figure 7>

5.2. Variable Renewable Curtailment

<Figure 8>

Variable renewable curtailment, in this case curtailment of wind onshore, wind offshore and solar generation, is one metric by which power system flexibility can be measured. Here curtailment is defined as the variable renewable power that cannot be used or stored and must be dumped due to operational constraints and/or insufficient demand. The high penetration of variable renewables in the 2030 PRIMES REF scenario indicate that this merits consideration, a factor which is not captured explicitly in PRIMES modelling. The ability of this approach to capture generation and interconnector flows at high temporal and technical resolution is critical in capturing the times & frequency at which Member States cannot utilise their full renewable generation and indeed export their surplus generation. Figure 8 is a graphic displaying the variable renewable curtailment for Member States in the model. Isolated power systems such as those of Malta and Cyprus have high amounts of curtailment by virtue of their isolation. Another Member State however that encounters curtailment is Ireland who are significantly better interconnected, thus perhaps raising the possibility to investigate remedial options such as storage and greater interconnection.

Maintaining minimum system inertia levels to maintain frequency are binding constraint that increase the levels of curtailment in the case of Ireland due to its relative isolation and high penetration on onshore wind generation. However, the scenario being analysed here is the reference scenario which is similar to a business as usual scenario, any further measures to increase the penetration of variable renewables in policy scenarios will see increases in the curtailment of variable renewable generation across the EU.

Curtailment is a factor in particular that could be mitigated by flexibility measures such as storage greater integration of the electricity sector with other sectors, such as thermal or transport sectors, in the form of demand response that could modify their demand to purchase the electricity cheaply that would otherwise have been curtailed.

5.3. Interconnector Congestion

<Figure 9>

<Figure 10>

Limited interconnection capacity can mean the benefits coming from renewable energy sources and potential electricity trade are lost, it is not easy to identify optimum levels of interconnection [58]. Congestion here is defined as the hours that a line is operating at maximum capacity. On average interconnection in 2030 was congested for 24% of the year. In figures 9 and 10 the number of hours

congested can be seen for the interconnection lines in the model simulation of 2030 which experienced high amounts of congestion (in excess of 2000 hours). Congestion on interconnection lines limits the efficient movement of electricity particularly in Central and Eastern Europe lines which raises concerns over the flexibility of the power systems within these Member States, highlighting the need for increased interconnection. Increased amounts of variable renewables coming online up to 2030 will put pressure on interconnection levels so that supply may meet demand to avoid curtailment. Policy scenarios with greater amounts of variable renewables would encounter greater difficulty in maintaining system inertia and have even more congestion. The congestion identified on interconnectors in this study cannot all be appropriated to the increased penetration of renewables, it may also indicate pre-existing infrastructural inadequacy within the system.

5.4. Impact of demand response

Demand response allowed the shifting of portions of peak demand to times when it was cheaper to serve this load, thus leading to a decrease in total system operation costs of 1%. Demand response also reduced overall interconnector flow by 3.9% which in turn reduced the wheeling costs associated with international flow of electricity. However, average number of hours for which lines were congested increased by 0.8% which indicates that although overall flow is reduced, line capacity continues to restrict and limit the efficient flow of electricity. This cost optimal load shifting also led to curtailment reduction, although the binding minimum levels of inertia and limited interconnection meant this potential remained limited for Ireland where curtailment remained above 10%. Under the implementation of demand response, overall CO_2 emissions increased by 3.2% due to demand shifting allowing less flexible coal generation to be used instead of flexible natural gas CCGTs to meet a flatter demand profile. Analysis of demand response merits further study and an extensive sensitivity analysis to better define its impacts and benefits as a flexibility measure under a variety of modelling assumptions.

5.5. Impact of maintenance of sufficient levels of grid inertia

The maintenance of sufficient levels of grid inertia was analysed with a focus on its impacts on the operation of the various synchronous grids of Europe. In order to maintain sufficient inertia on the power system at times of high penetration of variable renewable generation it is necessary in the model for other modes of generation to pick up the slack and remain online to provide inertia.

5.5.1. Continental European Grid (UCTE)

The impact of this maintenance of sufficient inertia is negligible for synchronously interconnected Member States on the central European grid due to the utilisation of inertia sharing between numerous of Member States. The minimum inertia requirement in this model to offset an outage of 2GW for the central European grid is 66,667 MWs. The inertia levels of the central European grid do not come close to this minimum level of 66,667 MWs with a minimum of 1,168,000 MWs for 2030.

5.5.2. Nordic Grid (NORDEL)

Similarly, under the PRIMES 2030 reference scenario conditions, NORDEL does not find the imposition of an inertia constraint binding. The inertia constraint of 38,600MWs to offset an outage of 1148MW is comfortably met with the minimum inertia in 2030 in excess of 200,000MWs. This owes primarily to the high installed capacity and generation of Hydro and Nuclear sources in particular.

5.5.3. National Grid of Great Britain

In Great Britain, the high penetrations of variable renewable generation sources, wind in particular, lead to a very variable inertia level on grid, as can be seen in figure 11, which does bind at the 66,667 MWs minimum to offset a 2GW outage. The composition of generation does not change significantly while constrained, the most effected generation source was Natural Gas CCGT which sees a 39% drop in the number of units started in 2030 to 54 starts per unit which remain online to provide inertia and a 2% increase in total system generation costs. The relationship between the online inertia and wind generation is apparent in figure 11, during windy months of winter the inertia levels are much more variable while during the less windy months of summer the inertia levels are much more stable. Whilst curtailment of variable renewable generation levels are minimal, the levels of curtailment would increase with increased penetrations of variable renewable generation under policy scenario conditions resulting in a decrease in the capacity credit of wind.

5.5.4. Baltic Grid

The impact is more notable in the case of the Baltic grid because the minimum inertia level of 23,333 MWs is a binding constraint to offset an outage of 700MW, this can be seen in figure 11. This leads to the requirement of increased capacity factors in thermal generation units with Natural Gas CCGT capacity factors increasing in this region by 9% to an average capacity factor of 13%. Increased synchronous interconnection would alleviate such problems associated with maintenance of inertia within the Baltic States and enable wider inertia sharing not currently possible via HVDC interconnection.

5.5.5. Irish Grid (SEM)

The current minimum inertia level as defined by the transmission system operator of Ireland is 20,000 MWs to limit the RoCoF to 0.5Hz/s [44] for an outage of 500MW. For this analysis the minimum inertia level was set as 23,333 MWs to offset an outage of 700MW and limit RoCoF to 0.75 Hz/s in anticipation of improved generator tolerance by 2030. The seasonal relationship between variability of wind generation and system inertia is very similar to that of Great Britain, visible in figure 11. Given Ireland's very high penetration of variable renewable generation and synchronously interconnected isolation, this constraint is quite binding and leads to significant implications for the Irish power system. As detailed previously, the high curtailment rate of variable renewable generation is a direct implication being in excess of 11%. Greater penetrations of renewable generation will lead to greater curtailment levels and reduced capacity credit of variable renewable generation.

<Figure 11>

6. Conclusions

Current long term energy planning and energy policy is largely informed by long term models that can struggle to capture sufficiently the operational integration of many renewable technologies for the power sector. This can often lead to misleading signals regarding the cost and difficulty of achieving carbon reduction targets, thus leading to sub optimal planning. This paper demonstrates a multi model methodological framework to address this which enables analysis of the robustness and technical appropriateness of the power sector results for a target year of the PRIMES energy system model which used to directly inform European energy policy development.

The specific value added by this paper is that it enables detailed operational analysis of the power sector not possible in a single long term energy system model approach. This additional modelling captures elements that are not represented in the PRIMES energy system model. This value added allows for the assessment of the impact of high penetrations of variable renewable technologies on the power flows across the European power system and their impact on the flexibility of the system in terms of pricing, interconnector congestion, capacity factor of fossil fuel generation, curtailment of variable renewable generation and provision of synchronous inertia. In the least cost dispatch simulation variable renewable generation formed 24.2% of total generation whereas PRIMES REF long term model results this was 26.6% of generation, indicating an overestimation of the European integration potential of variable renewable power in PRIMES by 2.4%. To achieve greater shares of variable renew able power generation such as those of over 80% as discussed in [3] will require very substantial increase in system flexibility and sectoral integration given the high congestion and curtailment identified in this paper. A key conclusion from this work is that for the assessment long term energy system planning a suite of models are best suited to informing long term planning of the energy system because it allows the strengths of each model to be exploited to better analyse the results of the other.

The impact of increased levels of variable renewable on conventional generation, especially natural gas fired CCGT plants, is quite profound once the capacity factor for this mode of generation is taken into account. This could cause concerns in regard to incentivising investment for conventional fossil fuelled generation in an energy only market which are of great importance from a generation adequacy and security perspective given their roles in frequency and voltage stability maintenance [59].

The capture of variable renewable curtailment and interconnector congestion enable the determination of the power system flexibility, implicit in this is the measurement of the ability of their power systems to absorb the variable renewables. These elements can be analysed within this multi model methodology, but are not at all captured in the PRIMES energy system model which can lead to overly optimistic results. They are important factors in the projection of power system development especially in cases such as PRIMES REF where there are high penetrations of variable renewables. The levels of curtailment experienced by Member States whilst being low (apart from certain outliers like Ireland, Malta, Cyprus and Portugal which reach levels of up to 11%) are still significant considering that this is a reference scenario that does not account for the implementation of policy measure post Spring 2012. Policy scenarios which impose greater amounts of variable renewable generation would encounter greater levels of curtailment. This work also highlighted interconnector congestion which on a European level was 24% on average, especially limiting the efficient movement of electricity particularly in Central and Eastern Europe lines. The heavy congestion, given the increasingly variable nature of power generation within the EU, highlights the need for increased interconnection especially in eastern and central European Member States under the reference scenario conditions.

The increasingly variable nature of power generation in Europe has clear implications for the reduction of the inertia of its power system and impacts on the frequency stability of the system. Although not a concern for the majority of European Member States, increased penetrations of variable renewable generation would increase curtailment of renewable energy and generation costs. Certain Member States are already experiencing such issues such as Ireland which experiences very high levels of curtailment under these conditions largely due to maintenance of inertia levels. Other regions such as Great Britain and the Baltic states would likely start to encounter such issues also under increased penetrations of variable renewable generation. The distribution of inertia by

Member State within this large system is not considered but could be a significant issue for a European system with high penetrations of variable renewable generation.

The benefits of power system flexibility in addressing certain issues highlighted by this work cannot be underestimated. Increased deployment of storages, demand response and better integration of electricity, thermal and transport sectors will play a strong role in the decarbonisation of the energy system [3]. This work showed that demand response, while effective in reducing total generation costs and reducing curtailment, can lead to increased emissions by causing less flexible coal generation to be used instead of flexible natural gas CCGTs to meet a flatter demand profile. This work also showed that demand response can have limited impact in terms of reducing interconnector congestion when used in the sole context of minimising overall generation cost. As such, demand response and other flexibility measures merit further study in the context of European energy policy development whilst accounting for interconnector flows.

Future work is recommended and planned to analyse aspects surrounding how better integration of electricity, thermal and transport sectors, and application of flexibility measures such as storage and demand response that will aid the move toward a European low carbon energy system. It is also planned to investigate in greater depth the nature of inertia provision under PRIMES reference scenario conditions regarding the distribution of inertia by Member State within this large system.

Acknowledgements

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Tables

Table 1

	2014		2030 PRIMES REF		
Country	RES-E (%)	VRES-E (%)	RES-E (%)	VRES-E (%)	
Austria	70.0	6.5	88.9	20.1	
Belgium	13.4	8.0	42.9	30.5	
Bulgaria	18.9	6.8	17	8.7	
Croatia	45.3	4.1	69.5	11.7	

Cyprus	7.4	6.2	31.5	29.4		
Czech Republic	13.9	3.8	14	3.5		
Denmark	48.5	36.2	73.1	58.8		
Estonia	14.6	6.6	31.2	22.4		
Finland	31.4	1.3	30.3	6.7		
France	18.3	4.7	37.7	23.6		
Germany	28.2	16.1	52.5	37.1		
Greece	21.9	13.4	44.4	26.9		
Hungary	7.3	1.8	15.5	6.9		
Ireland	22.7	18.2	66.1	58		
Italy	33.4	11.6	48.5	25.3		
Latvia	51.1	1.9	67.7	18.3		
Lithuania	13.7	6.4	13.2	2.2		
Luxembourg	5.9	2.6	43.6	26.3		
Malta	3.3	3.0	37.9	35.8		
Netherlands	10.0	5.6	36.2	26.1		
Poland	12.4	4.7	16.7	8		
Portugal	52.1	23.5	88.5	57.9		
Romania	41.7	13.0	46.3	12.7		
Slovak Republic	23.0	2.2	24	4.9		
Slovenia	33.9	1.8	34.8	6		
Spain	37.8	24.0	48.2	35.3		
Sweden	63.3	8.1	57.5	7.4	2030 PRIMES GHG40	
United Kingdom	17.8	10.0	50.3	44	RES-E (%)	VRES-E (%)
EU28	**27.5**	**11.0**	***44.5***	***26.8***	***49.3***	***30.3***

Table 1 - Percentage contribution of renewable electricity (RES-E) and variable renewable electricity (VRES-E) generation in terms by member state in terms of gross electricity generation

Table 2

	PRIMES	PLEXOS
Model Class	Energy system model	Power system model
Sectoral focus	Rich in sectoral disaggregation	Isolated sectoral focus
Model Objective	To determine optimal technology pathway development for the Energy system	To perform detailed operational analysis of the power sector
Temporal Resolution	Low temporal resolution (Day/Night/Peak)	High temporal resolution (5min-1hr)
Time Horizon	Long time horizon (2050)	Short term operational focus <1 year
Technical Representation	Limited to broad operational constraints due to low time resolution	Very high technical detail allows for reserve modelling, hydro modelling, multi-stage stochastic unit commitment and determination of ramping costs & flexibility metrics

Table 2- Comparison of PRIMES and PLEXOS model characteristics

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Table 3

Fuel Type	Capacity (MW)	Start Cost (€)	Min Stable Factor (%)	Ramp Rate (MW/Min)
Biomass-waste fired	300	10000	30	30
Derived gasses	150	12000	40	30
Geothermal heat	70	3000	40	30
Hydro Lakes	150	0	0	30
Hydro Run of River	200	0	0	30
Hydrogen plants	300	5000	40	30
Natural gas CCGT	450	80000	40	30
Natural gas OCGT	100	10000	20	30
Nuclear energy	1200	120000	60	30
Oil fired	400	75000	40	30
Solids fired	300	80000	30	30

Table 3 – A selection of the standard generator characteristics used

Table 4

Fuel prices	2030
Oil (in €2010 per BOE)	93
Gas (in €2010 per BOE)	65
Coal (in €2010 per BOE)	24

Table 4 - Fuel prices used in study

Table 5

Synchronous Power Grid	N-1 Outage (MW)	Assigned Minimum Inertia (MWs)
UCTE	2000	66,667
NORDEL	1150	38,628
National Grid	2000	66,667
Baltic Grid	700	23,333
SEM	700	23,333

Table 5 -The chosen N-1 contingency event for each synchonous grid analysed and the associated minimum inertia level assigned to limit RoCoF to 0.75 Hz/s

Figures

Figure 1

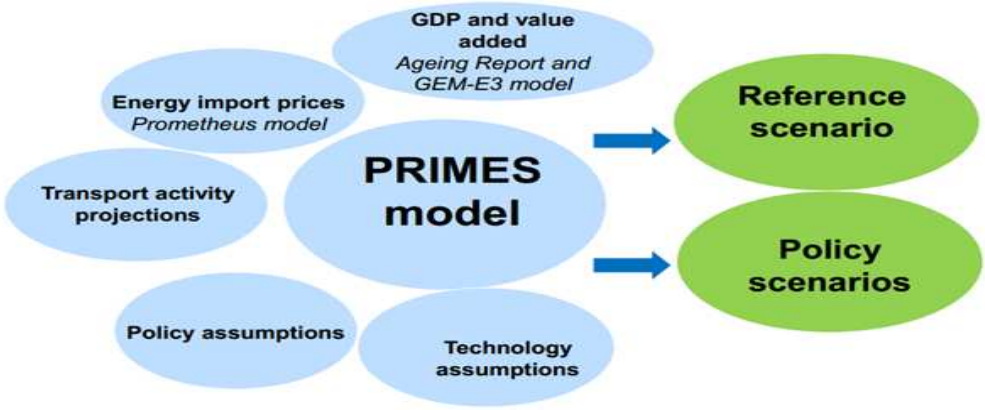


Figure 1 - Diagram of PRIMES Model Structure [48]

Figure 2

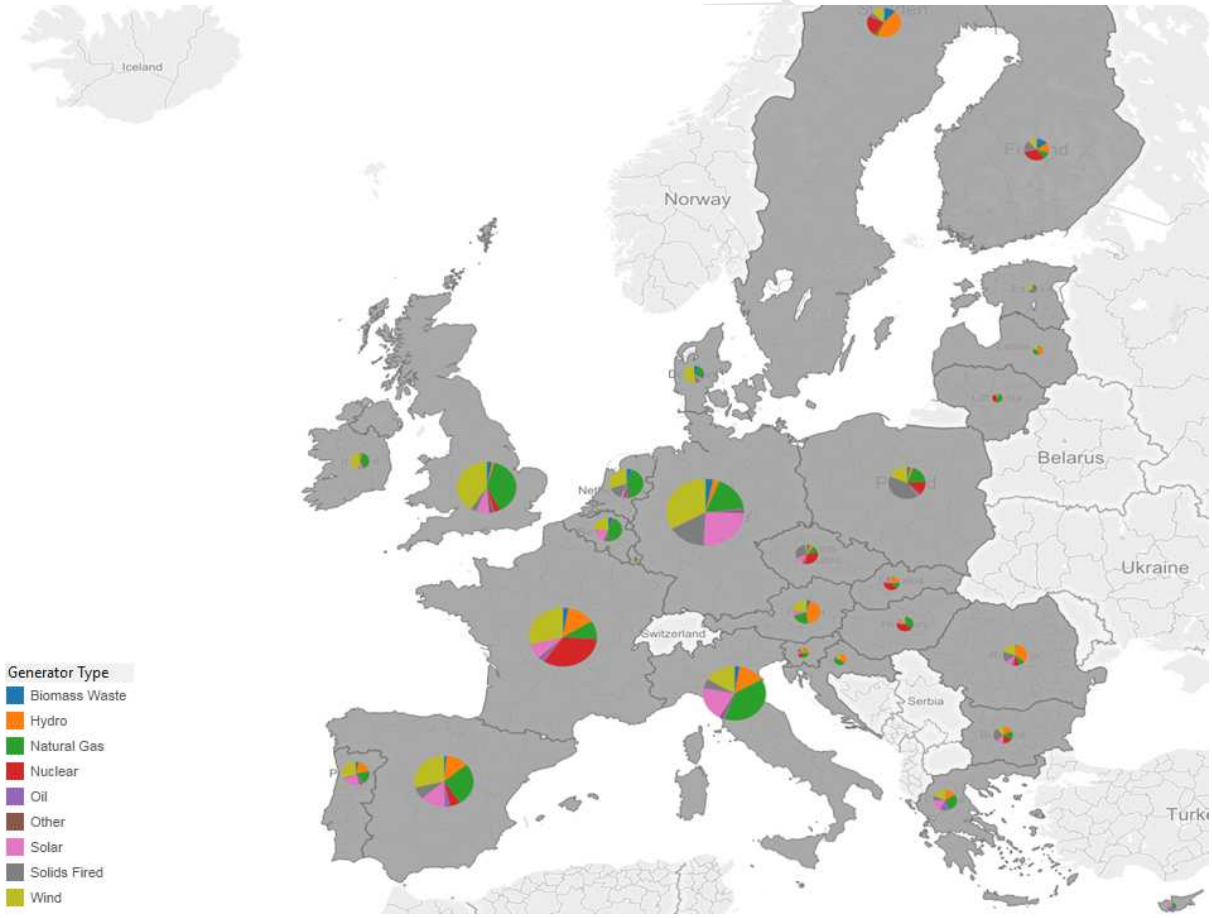


Figure 2 - The generation mix by Member State in the 2030 Reference Scenario Results

Figure 3

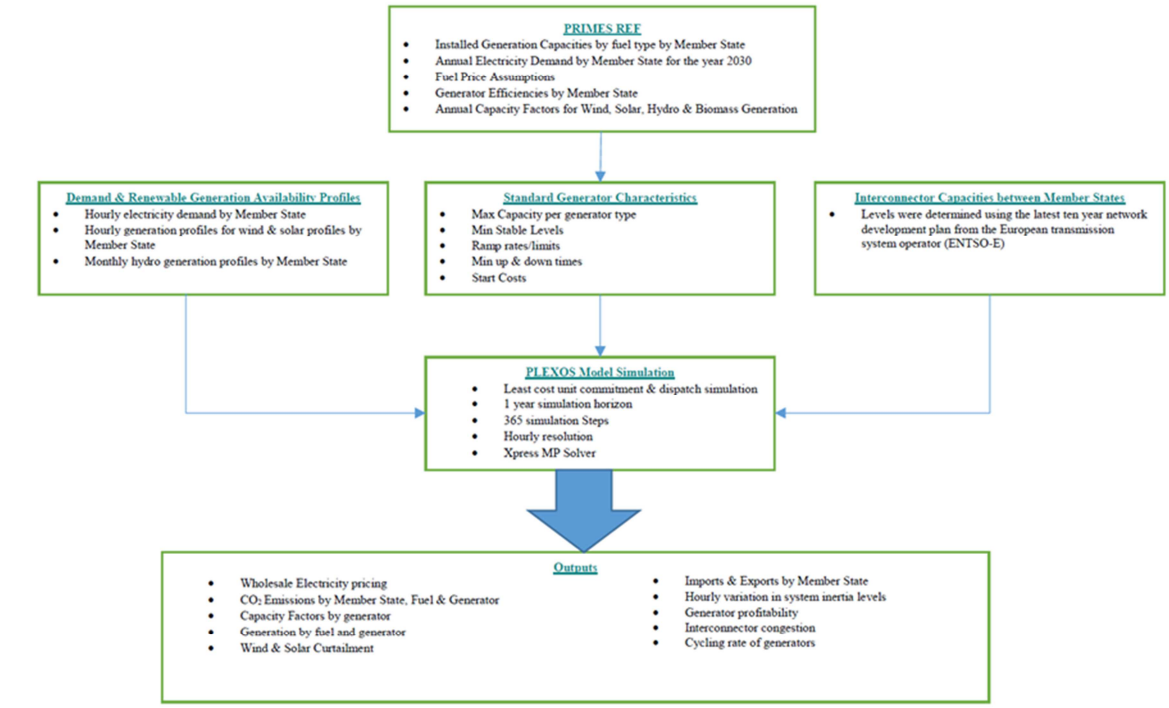


Figure 3 - Flow diagram of the modelling approach

Figure 4



Figure 4 - Interconnection as modelled with the EU-28 Power System Model

Figure 5

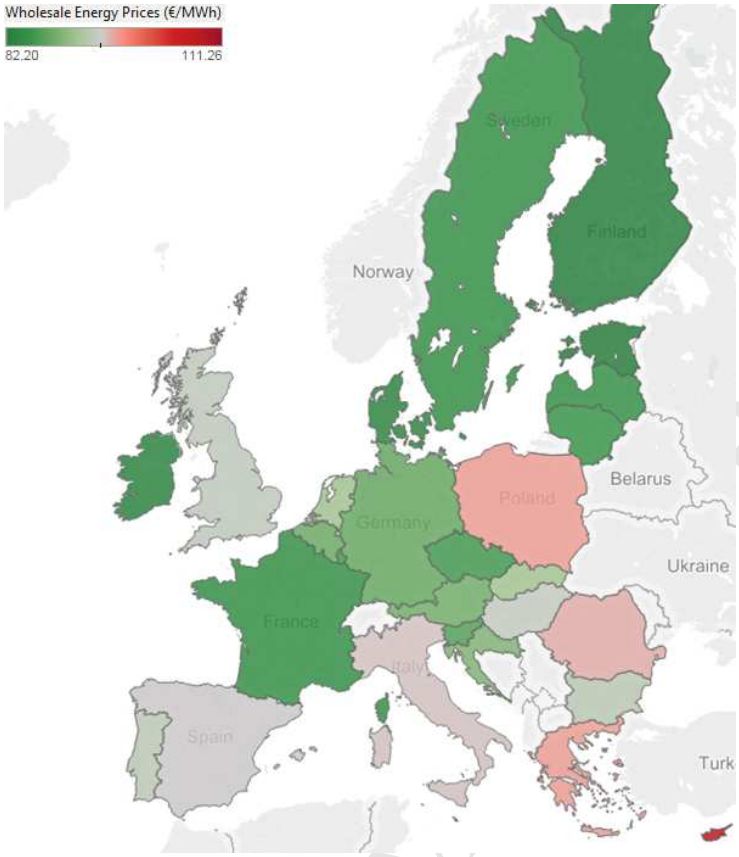
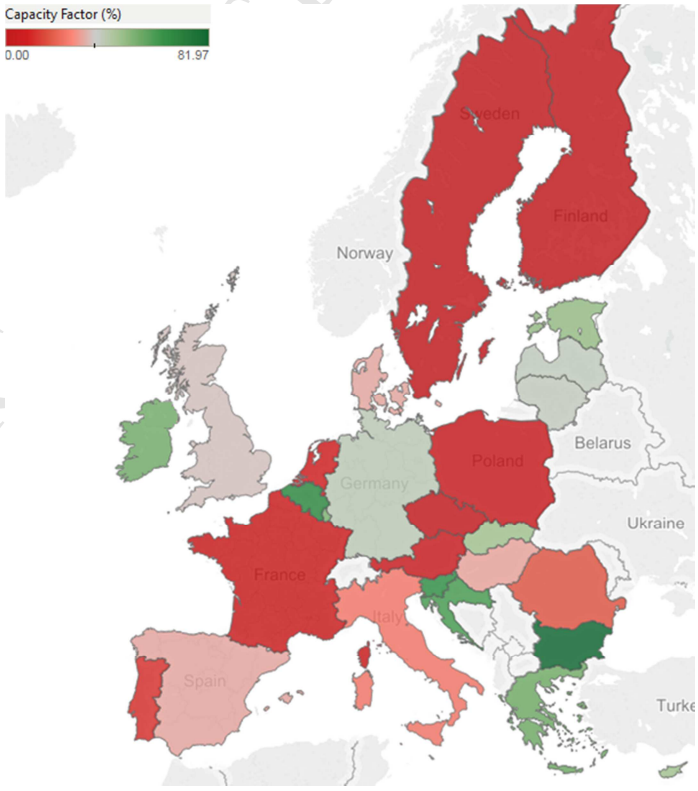


Figure 5 - 2030 Wholesale Energy Prices by Member State

Figure 6



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Figure 6 - 2030 Natural Gas Fired Plant Capacity Factors by Member State

Figure 7

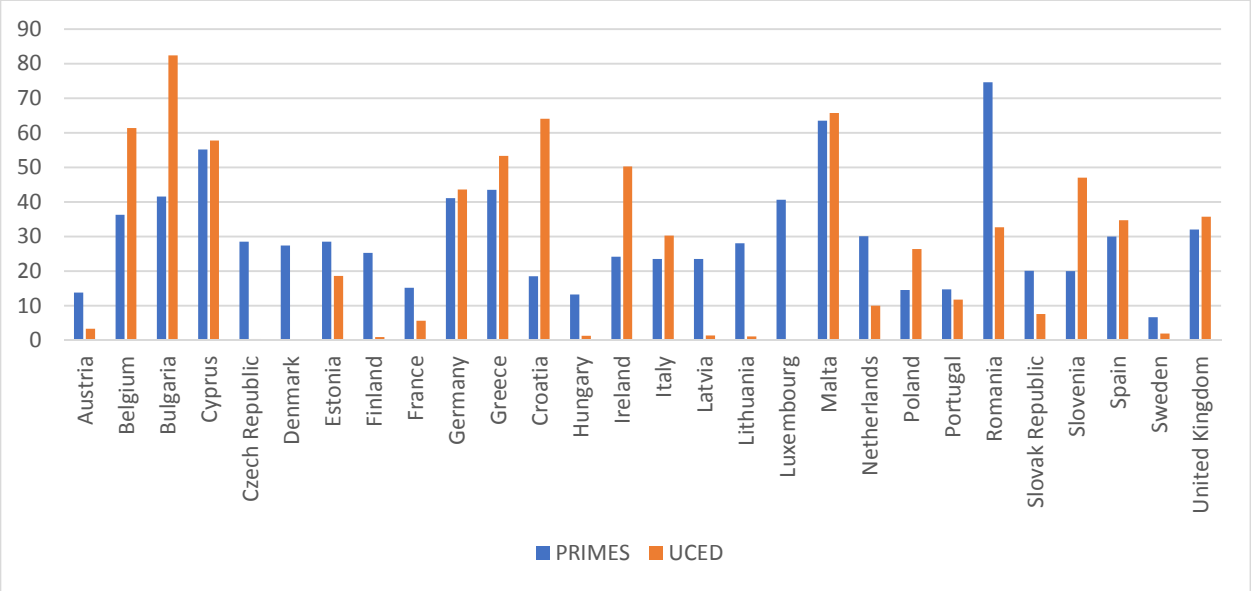


Figure 7 – 2030 PRIMES REF and UCED scenario Natural Gas Fired Plant Capacity Factors by Member State

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Figure 8



Figure 8 - Variable Renewable Curtailment by Member State

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Figure 9

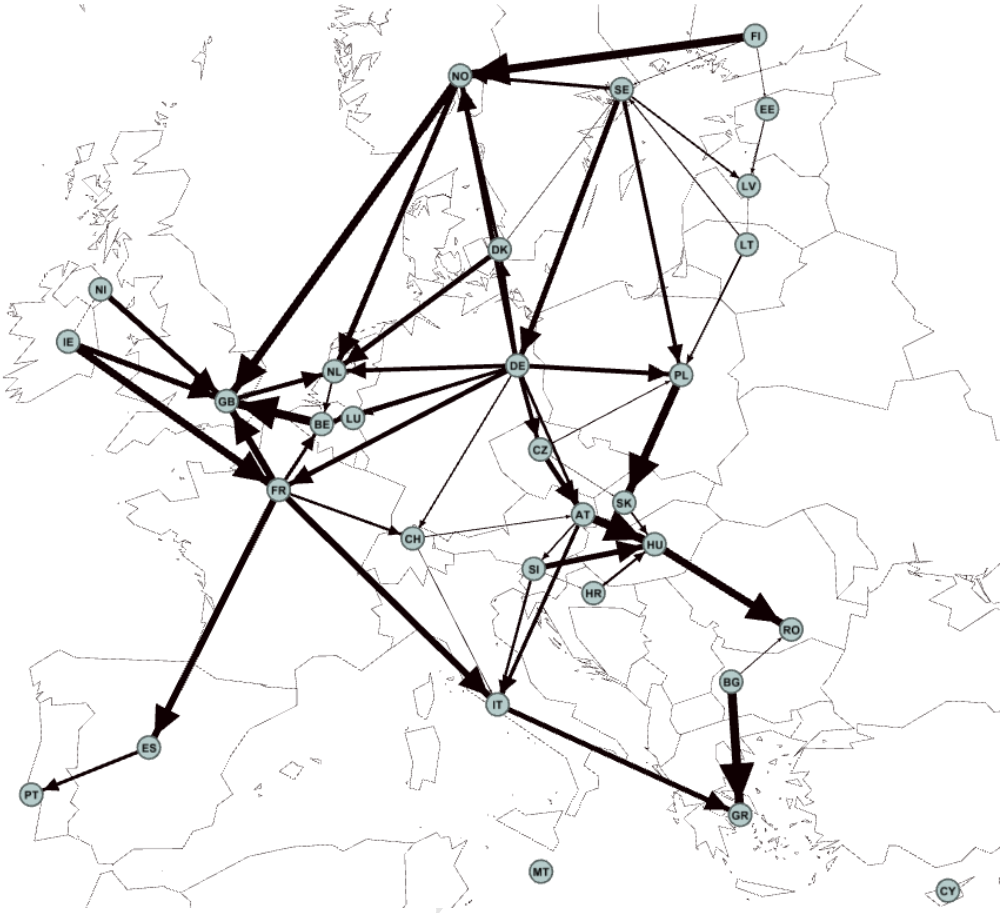


Figure 9 - 2030 Interconnector Congestion by Member State

Figure 10

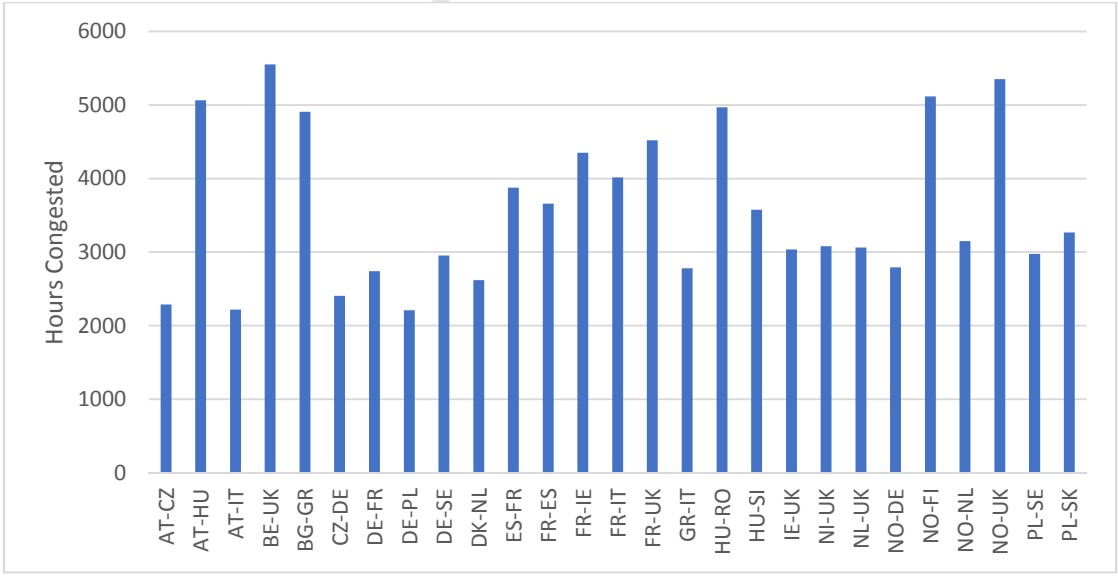


Figure 10 - 2030 Interconnector Congestion by Member State

Figure 11

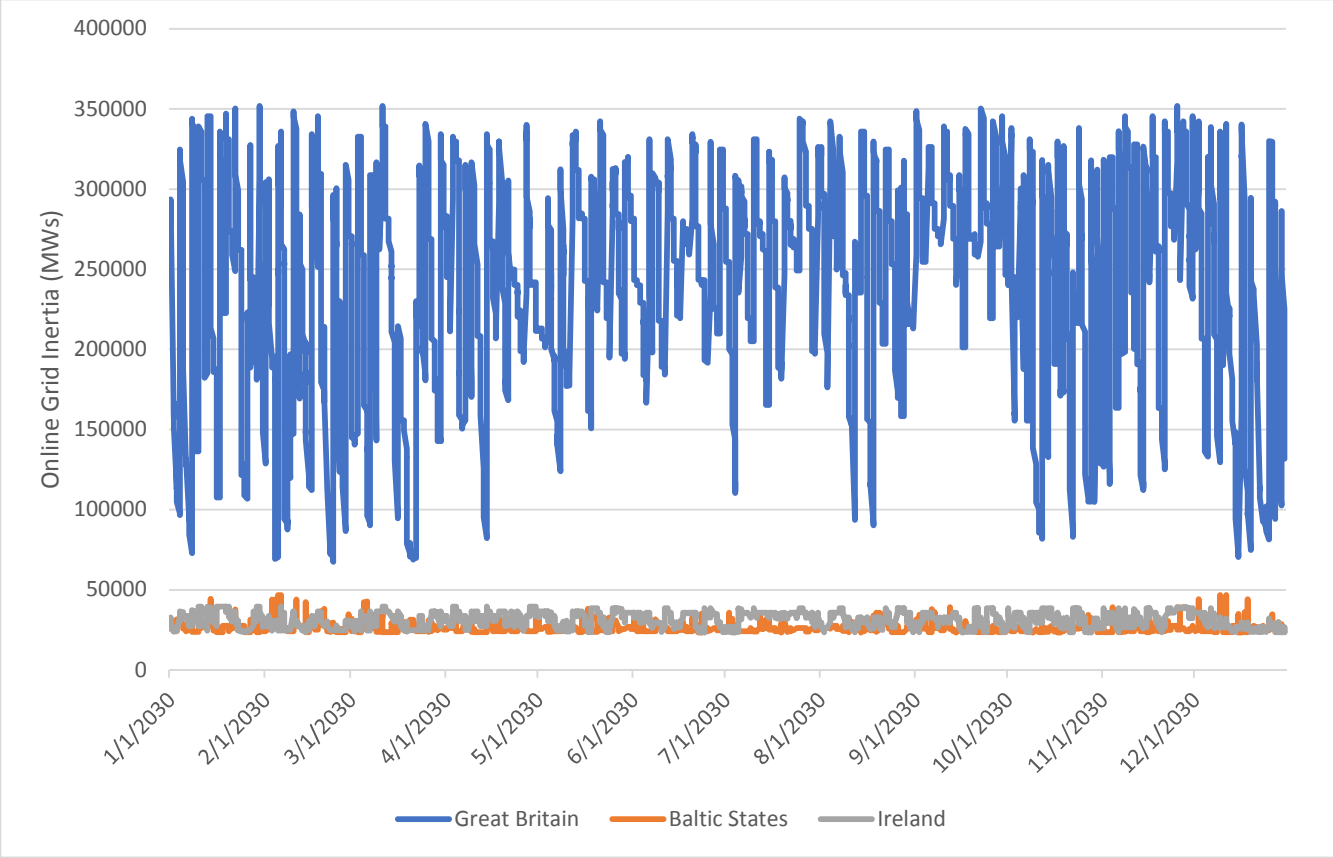


Figure 11 – Variation of online inertia over year for synchronous grids of Great Britain, the Baltic States and Ireland.

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