Ea Energy Analyses

System scenarios

April 2022

Development of the North European power market

Ea Energianalyse a/s

Introduction

This report has been procured by the Danish Energy Agency from Ea Energy Analyses A/S.

The main outcomes of the report are the consultant's best estimate of the future power system development in terms of wholesale power prices and power system capacities. Specifically, the following elements are included:

- Average power prices for the regions in the model.
- For each simulated year prices are determined as hourly electricity prices.
- Capacity development for the regions in the model
- Transmission system development

This report describes the main assumptions made, discusses the market development and the key uncertainties inherent to the nature of the task.

The projection of the future power system and power prices is highly uncertain. The methodology applied herein is based on a bottom-up representation of the fundamental mechanisms, which impact electricity prices on an hourly basis. However, this bottom-up approach in turn depends on projections of key input factors such as fuel prices, the price of CO_2 emissions as well as future energy policies and market setup, which are also highly uncertain. The report attempts to clarify some of the key uncertainties pertinent to the intended application but does not provide an exhaustive list of uncertain factors nor is it within the scope to conduct extensive detailed sensitivity analysis. Selected sensitivity analyses based on the client's input, are shown.

The work shown in this report has been commenced before the Russian invasion of the Ukraine, and the subsequent impacts on energy markets and political strategies. While the short term development of the power system is not the core focus, also the longer term developments can be affected by a change of gas prices and political strategies to diversify current gas usage and sourcing. The current results assume that gas prices will return to a long term level in 2030, which is based on the World Energy Outlook 2021, published before the current crisis.

Where results are compared to TYNDP-scenarios, the base for comparison is the TYNDP-scenario draft published in October 2021. Final scenario dataset was published in April 2022, but is not reflected in the current report. Neither of the two version incorporate the impacts of energy crisis.

Base scenario for power prices

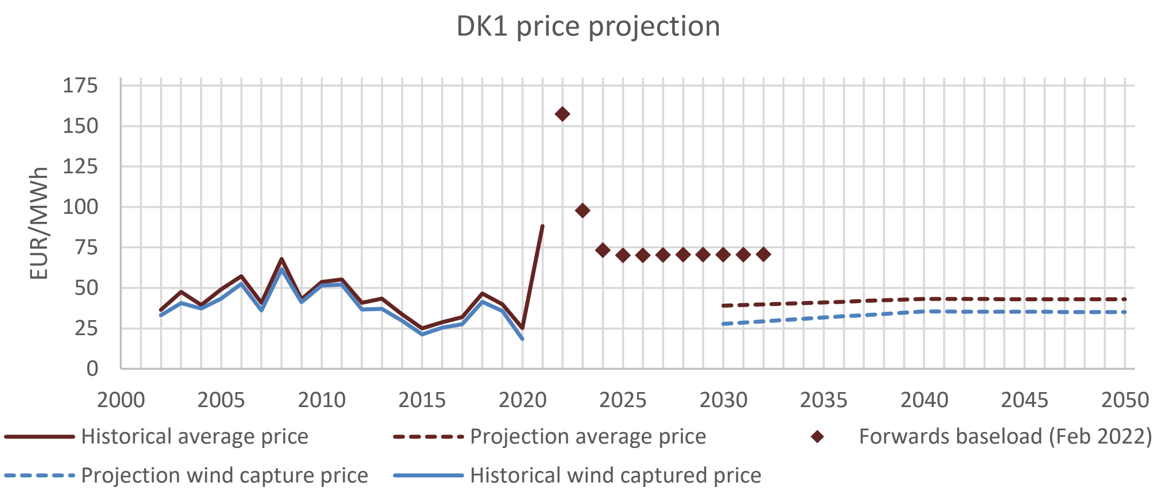
Current (primo 2022) price surges expected to decline when natural gas prices decline.

Stable power prices from 2030 towards 2050.

Captured prices for wind are between 25% and 18% below average prices. Long term, price differences do not increase in spite of increasing penetration owed to demand flexibility from especially electrolyzers.

The projection shows prices around 40 €/MWh in 2030, slightly above averages for the past 10 years, but below the high prices of 2021. In the short term, current high gas prices will increase power prices. Towards 2030, increases in demand, fuel and CO_2 prices are offset by decreasing cost of renewable generation and national RE deployment targets, which in some regions enforce renewable buildout beyond what pure market prices would support. After 2030, buildout of the transmission system and increasing demand reestablishes a balance between cost of renewables and market returns. However, depending on the pace of renewable buildout, demand increases and international transmission system buildouts, prices can be lower also after 2030.

Volatility of power prices increases throughout the period compared to historic levels, thereby increasing the importance of flexible dispatch planning for both generators and consumers to ensure profitable operation. Flexibility on the demand side, mainly for electrolyzers can limit price volatility.



Source: Historical prices based on data from ENTSO-E transperancy platform; future-prices based on Nasdaq-OMX, 03-06-2021. Product calendar is limited for DK-W and DK-E prices, which are based on system forwards and CfDs. CfDs are only available three periods ahead. For 2021, averages of quarterly futures are shown. For 2022 to 2030, yearly futures are shown. Projections are based on Ea model calculation. All prices shown as fixed DKK2020-prices.

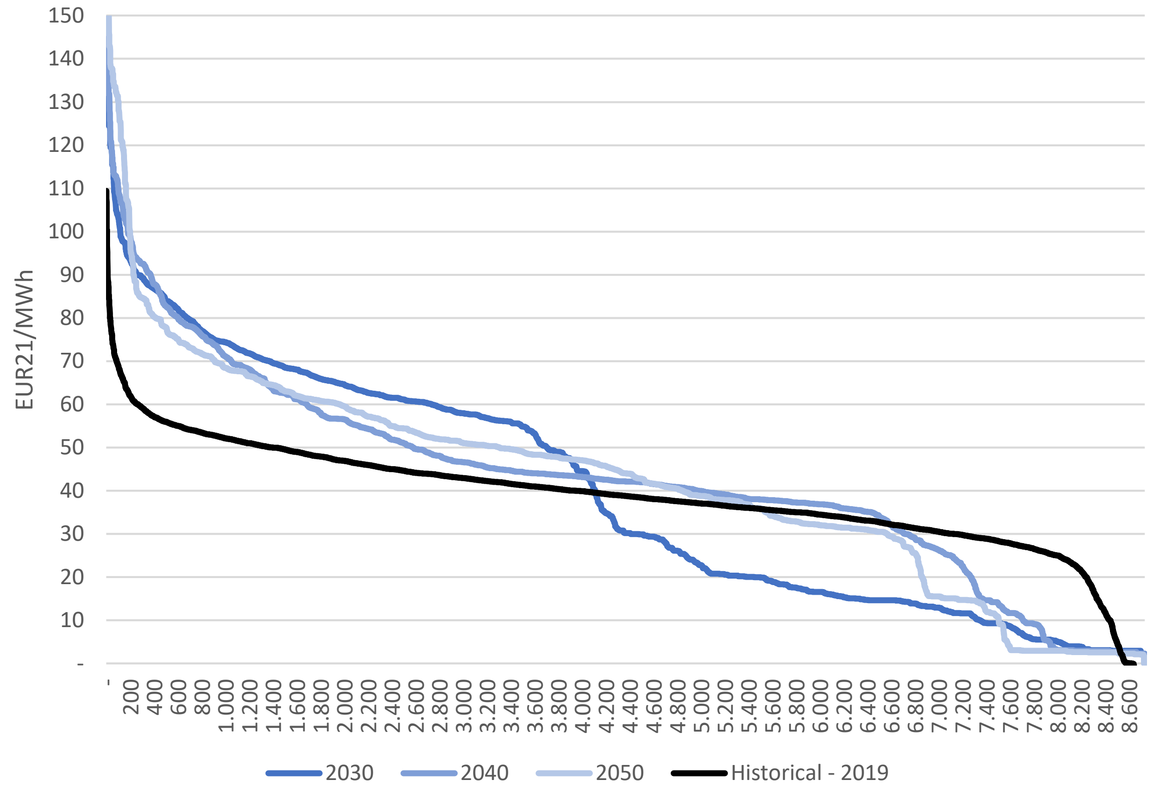
Overview on central assumptions

Topic		Assumptions
General		EU: Ambitions by EU Commission long-term scenarios towards 2030 based on impact assessment for Fitfor55-policies (Fitfor55 2020 - Stepping up Europe's 2030 climate ambition). Denmark: Government 70% climate target has further increased RE ambitions. Effect on national demand based on Danish Energy Agencies estimates in "Analyseforudsætninger for Energinet 2021" (AF21). System scenarios are shown until 2050. Where applied references do not cover the entire time horizon, estimates are applied.
Targets	**RES**	Minimum buildout based on TYNDP 2022 draft scenarios, National trends. Increased targets for Germany, based on new governments visions for 2030 stated in the coalition agreement from November 2021, followed up by a bill in April 2022. Ambitions include a significant increase of ambitions towards 2030, setting out 80% renewables in the electricity MIX, supported by 30 GW of offshore wind, 100-130 GW of onshore wind and 200 GW solar power. As a minimum level, a more modest buildout of 80 GW onshore wind and 150 GW solar power has been assumed, since the historical buildout for onshore wind and solar power has proven to be challenging. Higher rates are possible in modelling on market terms.
Prices	**Fuel**	WEO Sustainable Development 2021 Updated futures
	CO_2	2030-estimate 100€/ton based on DEA projections
Electricity demand	**Classic**	EU: European Commission Fitfor55 2020 – MIX-scenario DK: Analyseforudsætninger 2021
	EVs	EU: European Commission Fitfor55 2020 – MIX-scenario DK: Analyseforudsætninger 2021
	Individual heat	EU: European Commission – COMBO-scenario DK: Analyseforudsætninger 2021
	Industry	EU: European Commission Fitfor55 2020 – MIX-scenario DK: Analyseforudsætninger 2021
	P2X	EU: European Commission Fitfor55 2020 – MIX-scenario National demand for Denmark based on AF21, equivalent to 5 TWh electricity demand in 2030. Option for export of P2X.
Offshore wind & solar power		DK: Based on AF21. Two additional wind farms before 2030 (2GW). Energy Island in Eastern Denmark connected to Germany. Total offshore in DK: 2025: 3,1 GW, 2030: 7,8 GW
Self sufficiency		No self sufficiency requirement applied for Denmark, net import possible

Hourly prices

Hourly price profiles are simulated for 2030, 2040 and 2050.

- Deterministic models tend to underestimate the amount of both high and low prices due to perfect foresight. Unexpected events (outages of power plants and transmission lines, demand fluctuations and variable generation changes) will change the level and number of high and low prices



Hourly prices are calculated in a dispatch simulation, taking into account the effects of unit commitment. Hourly dispatch simulation is not able to directly ensure balanced economy for all investments, and therefore average prices from hourly simulations differ slightly from prices achieved in investments optimization based on aggregated time resolution (see further below for more details).

While price volatility is significantly higher compared to todays prices, the ever increasing shares of variable renewable generation do not lead to ”steeper” curves beyond 2030, owed to the increased power system flexibility induced by especially electrolyzers.

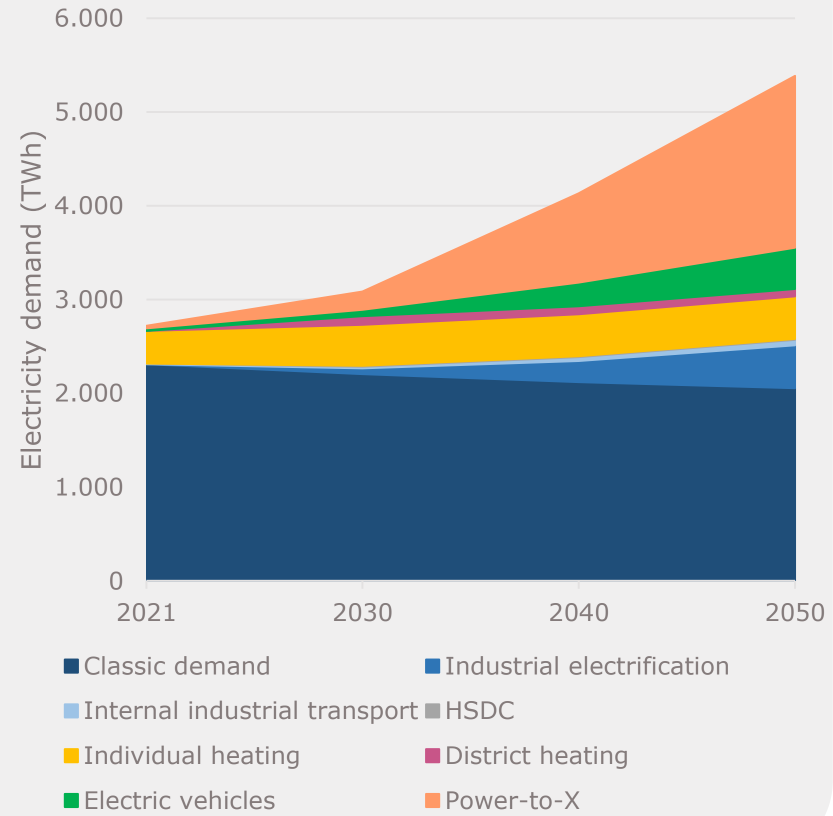
** 2020 shows statistics. Due to the low electricity prices during 2020, the curve is not representative for previous years.*

Power consumption development - Europe

Demand projections for future years are based on the European Commission's impact assessment for Fitfor55-policies (Fitfor55 2020 - Stepping up Europe's 2030 climate ambition), following the MIX scenario, which aims for 55% emission reductions in 2030, paving the way for climate neutrality in 2050. While the total demand in the MIX scenario increases with about 100% between 2020 and 2050, it does not project very high levels of direct electrification of the transport, heating and industrial sector. Rather, the MIX scenario sees clean fuels such as hydrogen as a main strategy to transform and store energy. Following the importance of clean fuels in the MIX scenario, almost 70% of the power demand increase (2020-2050) stems from P2X. Increased levels of direct electrification and subsequently lower levels of indirect electrification (P2X) will lead to a lower total electricity demand due to higher efficiency of direct electrification.

- **Classic demand** contains all demand which does not fall under the other categories. The demand is mainly modelled with demand profiles based on the consumption in 2014.
- **Electric vehicles demand** includes all electricity for road transport. This demand is flexible, and an increasing share can be moved for 4 hours.
- **Electricity for individual heating** includes electricity consumption for space heating in buildings, which is modelled as heat demand. The demand is supplied by heat pumps and electric boilers. All of the individual heat demand is flexible and can be moved 2 hours.
- **Electricity for electrification of industrial energy demand** is included as the growth in electricity use in the industrial sector (compared to 2015), considering increasing energy efficiency. The demand is modelled as heat demand which can be fully supplied by coal, natural gas and oil boilers. When advantageous, additional electric boilers can be installed to supply the heat demand.
- **Electricity for district heating** is based on model optimization. Heat pumps and electric boilers are among the options to supply the district heating demand. Other options are fuel-based district heating generation from heat only boilers or CHP.
- **Electricity for P2X** is included based on the consumption of e-gasses, e-liquids and hydrogen. A P2X efficiency of 70% is assumed for hydrogen and 60% for e-gasses and e- liquids. If profitable, storages can be installed to move portions of the demand

Power demand in the model area (Europe)



Sources:
European Commission (2020): Stepping up Europe's 2030 climate ambition - Investing in a climate-neutral future for the benefit of our people

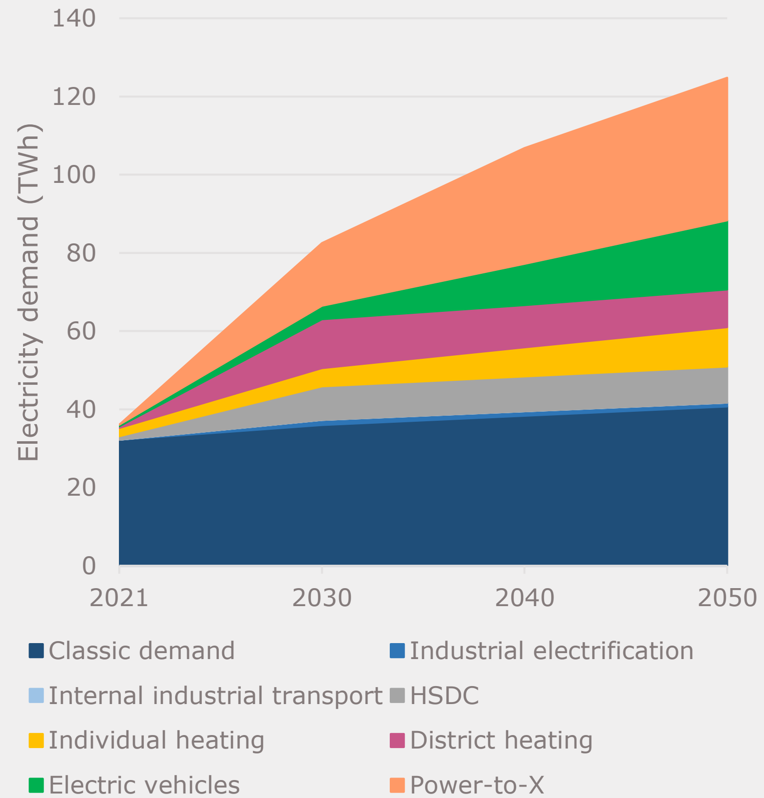
Power consumption development - Denmark

Demand projections for Denmark are based on projections by the Danish Energy Agency, set up for use by the Danish Transmission system operator Energinet ("Analyseforudsætninger 2021"). The assumption are meant to "support" a development towards the Danish governments' target of reducing GHG emissions by 70% in 2030 compared to 1990. Towards 2050, trends from AF21 are continues. This approach tends to overestimate demand for electric vehicles and individual heating, as the pace of increasing demand is expected to slow down, as sectors reach high electrification levels.

Assumptions are supplemented with the following

- Electricity demand for P2X-generation can be increased for export purposes, thereby supplying P2X-demand in other European countries. Distribution of P2X-generation across Europe is subject to model optimization.
- Electricity demand for district heating is subject to model optimization, minimizing the cost of supplying the Danish district heating sector under the given regulation in terms of fuel taxes and subsidies.
- Denmark is not restricted to ensure national generation, which on an annual basis can supply national demand.

Power demand in Denmark



Sources:
Energisytrelsen (2021): Analyseforudsætninger til Energinet

Demand flexibility

Demand projections cover 6 main categories outlined below. Flexibility options are modelled specifically for each category.

Demand bucket	Description	Flexibility	Associated cost
Classic	Classic electricity demand mainly for households, the industry and service sector. Contains demand types not explicitly covered under the other categories.	In 2050, 10% of average demand is assumed flexible and can be moved in time with up to 2 hours. In 2030, 3% of average demand is assumed flexible.	Two main cost levels. 50% of flexibility activated at a cost of 15 €/Mwh, 50% of flexibility activated at a cost of 30 €/MWh.
Electric vehicles	Demand includes all **electricity for road transport.** Initial profile is based on charging patterns matching transport demand (Estimated for individual countries based on empirical data from Norway)	Towards 2050, 65% of total load for electric road transport will participate in flexible charging and be able to move planned charging by up to 4 hours. The EV flexibility considers driving patterns and ready-to-drive constraints	Flexibility activated at a cost of 15 €/MWh.
Individual heating	Includes electricity consumption for **space heating in buildings**. The demand is supplied by heat pumps and electric boilers.	Flexible heat generation by adjustments to initial demand profile. Average demand can be moved 2 hours.	Flexibility activated at a cost of 10 €/MWh.
Industry	This demand **represents industrial heat demand** which has the potential of being electrified towards 2050.The electrification potential and associated cost depend on the temperature level, but distinguished by fuel type (demand today served by coal, natural gas and oil).	Flexibility enabled by partial fuel based backup to supply process heat (fuel switch).	Investment and operational cost for electric boilers included. Fuel switching requires covering fuel and emission cost for alternative fuel.
District heating	**Heat demand for district heating** is included. Heat pumps and electric boilers are among the options to supply the district heating demand. Other options are fuel based district heating generation from heat only boilers or CHP.	Flexibility consists of the option to fulfill the heat demand by electricity or other heat generation, depending on the power prices	Investment and operational cost for electric boilers or heat pumps included. Using alternative options for heat generation yields additional cost.
Power-to-X	**Demand for production of e-gasses, e-liquids and hydrogen** based on EU commission scenarios. Modelled as electricity consuming generation facilities (electrolysers).	Model optimized hydrogen storages can be installed to enable flexible use of electrolysers, while demand is modelled constant.	Investment and operational cost for electrolysers and cavern storages included.

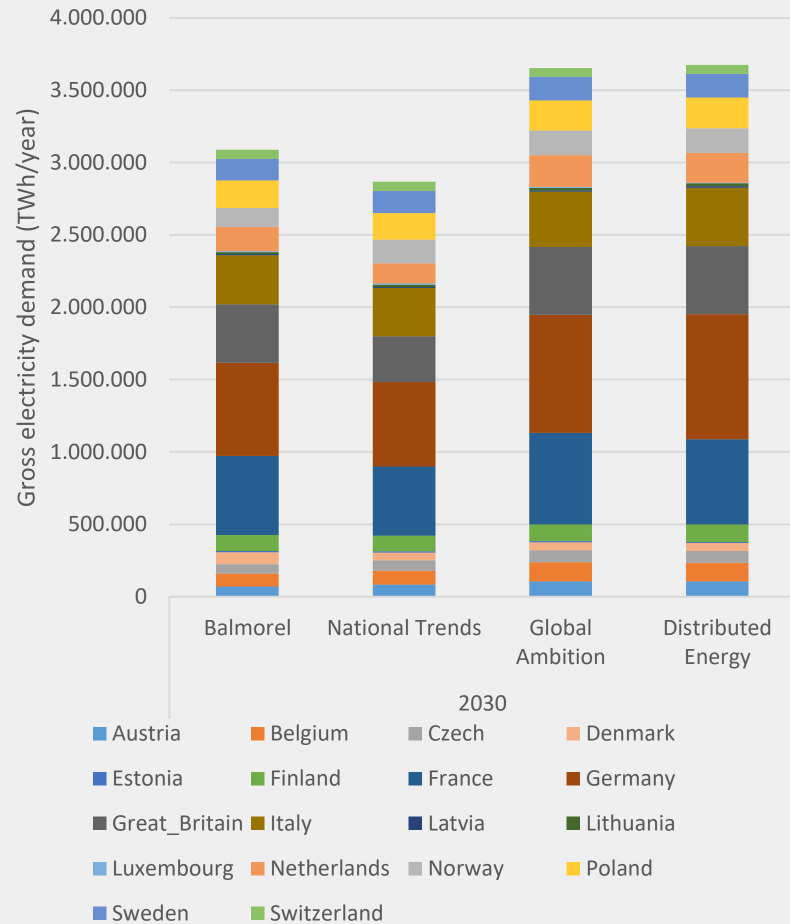
Power demand by country

Scenarios for the European Power system published by the European Commission do not directly provide detailed data and all demand types, or how they are distributed on countries. Therefore, assumptions have been applied:

The total estimates for electricity demand by type are distributed on different countries using keys:

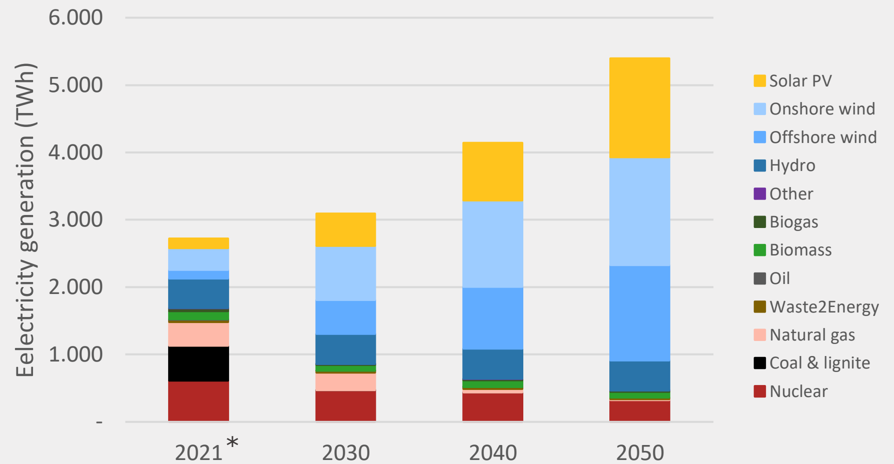
- Classic demand: TYNDP18 scenarios BE 2020 and GCA 2040.
- Electric vehicles: Number of cars from Eurostat
- Individual heat pumps: Number of heat pumps per country from TYNDP18 scenarios BE 2020 and GCA 2040.
- Industrial electrification: Industrial energy use (coal, oil and gas) based Eurostat.
- Electricity for P2X: Average key according to number of cars (proxy for heavy transport) and industrial energy use.

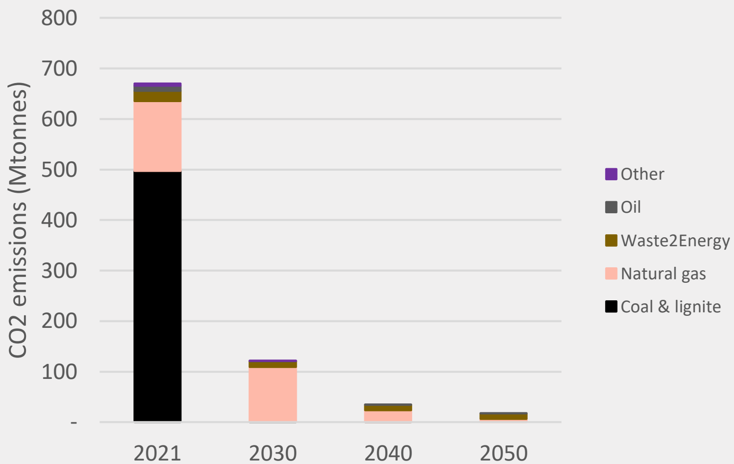
Both ENSTO-E's and Balmorels demands distribution are subject to significant uncertainty in the light of the development of new demand types.

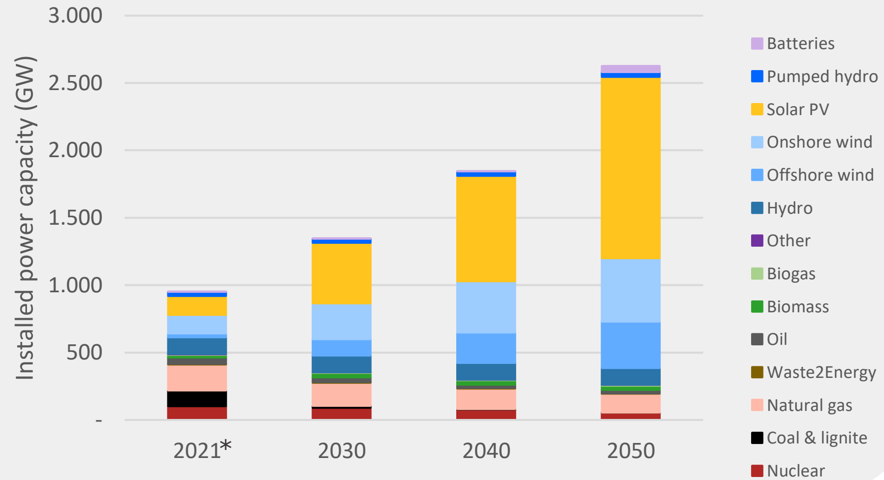


Power system development in Europe

- Fast transition to higher RE generation shares reaching 72% in 2030 and 87% in 2040.
- CO_2 emission reductions of up to 88% by 2030 and 97% by 2040 compared to 2005. Reductions take place alongside increased electrification.
- Wind and solar generation account for 55% of generation in 2030 increasing to 73% in 2040
- Significant reduction in thermal generation capacity of approximately 40% in 2040 compared to 2021



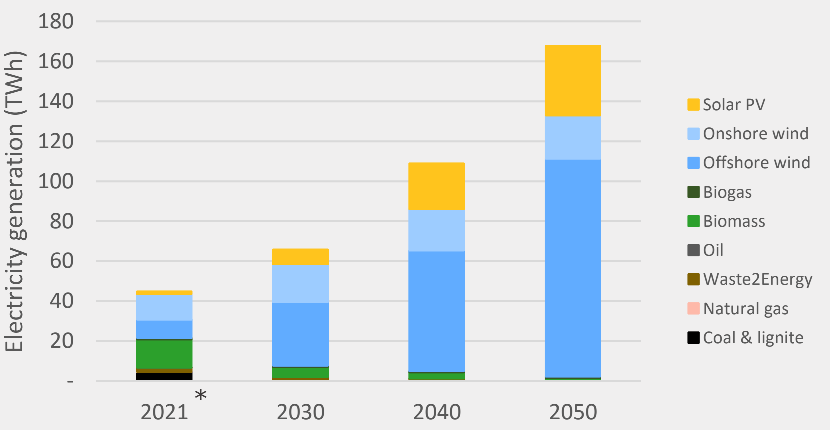


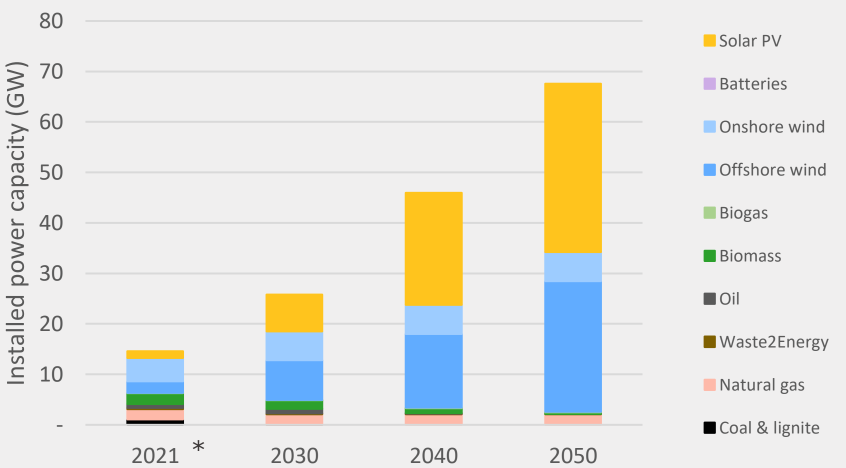


*2021 has been simulated separately based on historical fuel prices for 2021 to provide a base year for comparison. Due to the nature of the fuel prices in 2021, any investments or decommissions performed by the model 2021 have been disregarded and reset in 2025.

Power capacity development in Denmark

- Strong offshore wind deployment expected as a result of energy agreements from June 2018, the governments 70% target and agreements on energy islands etc.
  - Thor (900 MW) and Hesselø (1,000 MW) assumed operational in 2026 and 2027.
  - Two additional offshore wind farms, total of 2 GW operational in 2030.
  - Energy Island at Bornholm assumed operational with 1,000 MW in 2030 and additional 1,000 in 2031. Connected to Denmark and Germany
  - Energy Island in the North Sea assumed operation with 1,5 GW in 2033, connected to Denmark. Additional 1,5 GW operational in 2034 including 1,5 GW transmission to the Netherlands
- Onshore wind deployment on market terms beyond 2020. Minimum level ensured equal to AF21 (increasing to 5,7 GW in 2030)
  - Maximum level of 5.7 GW assumed as a result of increasing local opposition and planning constraints. Increased levels of onshore deployment can reduce the need for solar power.
- Solar deployment on market terms beyond 2020. Minimum level ensured equal to AF21 (increasing to 7.3 GW in 2030)
  - Total deployment assumed to be restricted by local opposition and planning constraints. Maximum deployment around 11 GW in 2030 increasing to 33 GW in 2050
- Thermal generation reduced to around 5 GW in 2030 and 3.2 GW in 2040 based on enforced phase out of coal power plants and model optimization.
  - Subject to uncertainty. Important factors include:
    - Future framework for decentral generation capacity in Denmark
    - Fixed O&M cost to keep capacity operational for few full load hours
    - Ratio between fuel and power prices



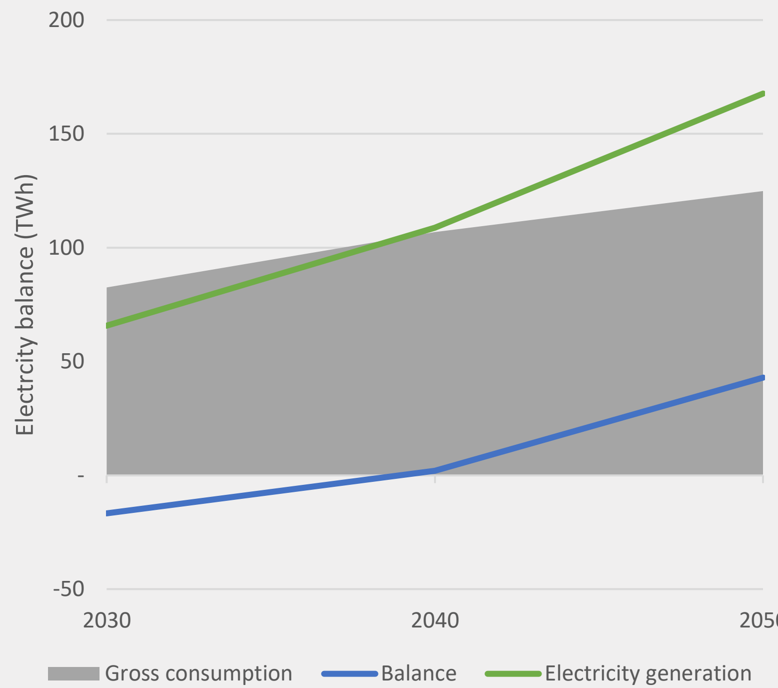


*2021 has been simulated separately based on historical fuel prices for 2021 to provide a base year for comparison.

Denmark - Power system balance

Towards 2030, Denmark is a net importer of electricity, with a net annual import of around 17 TWh. Towards 2040, the buildout of electricity generation outpaces demand increases, leading to a balance between annual generation and import. Towards 2050, the renewable potential in Denmark and options for reinforcing the European transmission system lead to net exports of up to 40 TWh/year. These numbers assume, that offshore wind generation in Danish waters is allocated to the Danish electricity balance, regardless of the physical interconnection to the power system.

Expoert options are sensitive to potential assumptions on renewable resources both within Denmark and neighbouring countries.

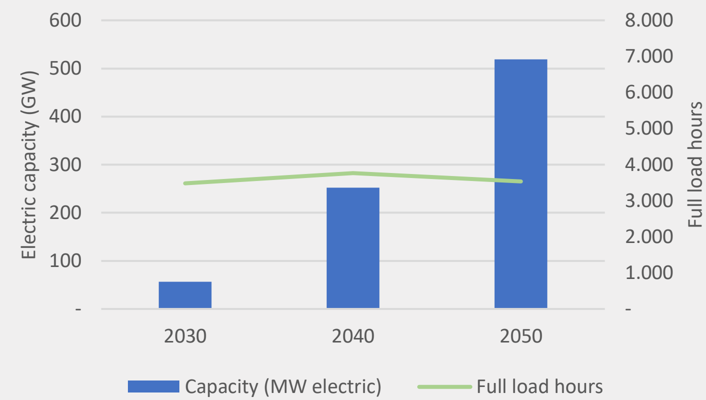


P2X production

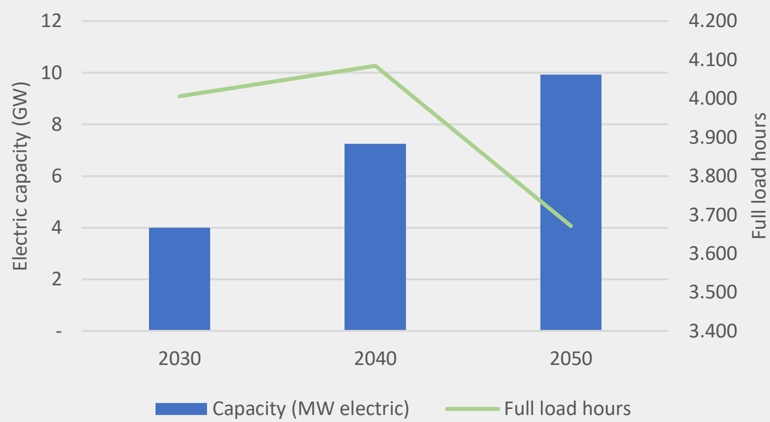
P2X demand increases significantly over the period. At the same time, the sector is currently in very early development stage and faces significant uncertainties.

- P2X demand is based on the European Commissions MIX scenario for 2050. For 2030 10% of the 2050-level is assumed.
- Final P2X demand is assigned to the estimated end-use regions. However, P2X-production can take place in other regions, depending on available generation resources. For Denmark, production levels are estimated to be higher than national demand.
- Total electrolyser capacities are estimated to 56 GW in 2030, app. 16 GW more than the target in European Commissions hydrogen strategy from 2020.
- European P2X production will likely face international competition, e.g. from fuel production based on solar photovoltaic in more southern regions. Higher production cost in Europe can potentially be offset by saved transport cost. Here, European P2X demand is assumed to be supplied by European P2X generation.
- Flexible operation of electrolysers will significantly impact the price duration curves for 2040 and beyond. High flexibility leads to 'flat' duration curves, as shown above. Lower flexibility (e.g. due to high capacity cost or tariffs for electrolysers) would lead to steeper duration curves.

Electrolyser capacity model area (Europe)



Electrolyser capacity Denmark

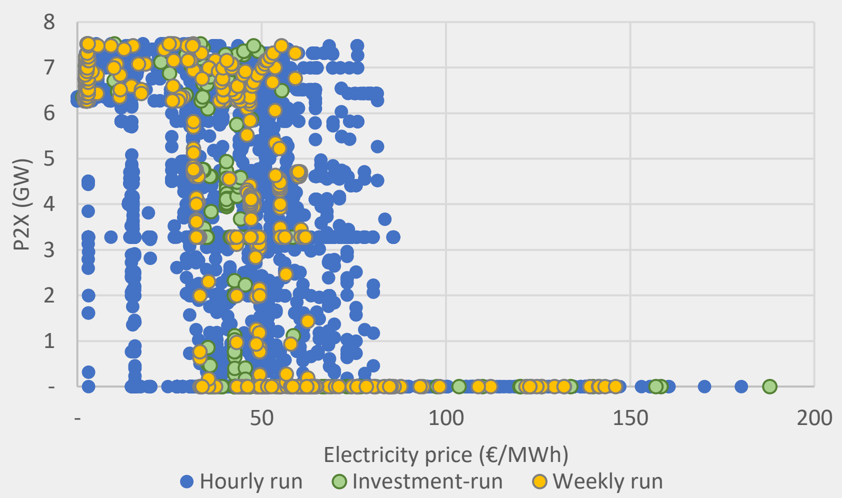


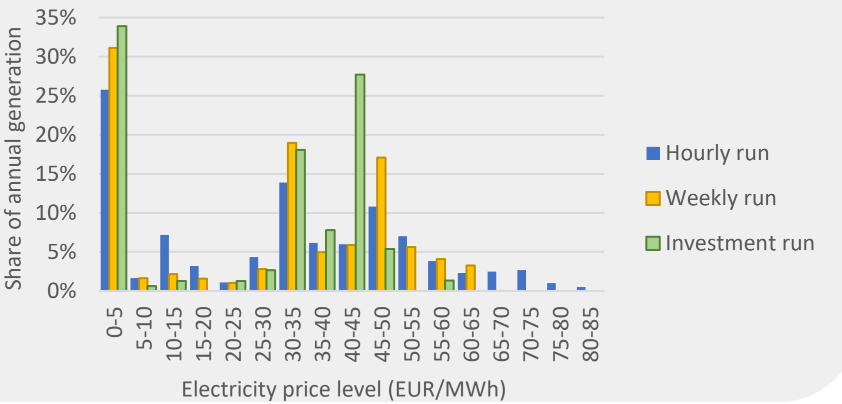
P2X production

Optimisation of P2X production and storage capacity is performed in the investment run, showing average captured prices between 20 and 28 €/MWh. In the subsequent dispatch runs, the increased timely resolution leads to higher spread of power prices and thus higher spread of prices at which electrolysers operate. However, average captured prices are only slightly affected.

The hourly dispatch optimization is bound to specific production volumes (based on aggregated time resolution simulations) as it optimizes operation with a weekly optimization time horizon, as opposed to the aggregated optimization runs, which cover the entire year. In some weeks, this leads to operating electrolysers at higher electricity price levels, if the hourly simulation reveals, that the electricity system is more strained, than the aggregated simulation suggested. In practice, this leaves room for further optimization, by allocating higher generation volumes to weeks with lower prices. On the other hand, foresight is not perfect, and and realistic optimization might in fact lead to occasional operation of electrolysers at higher prices or not being able to fully utilize weeks with lower prices.

Electrolyser operation

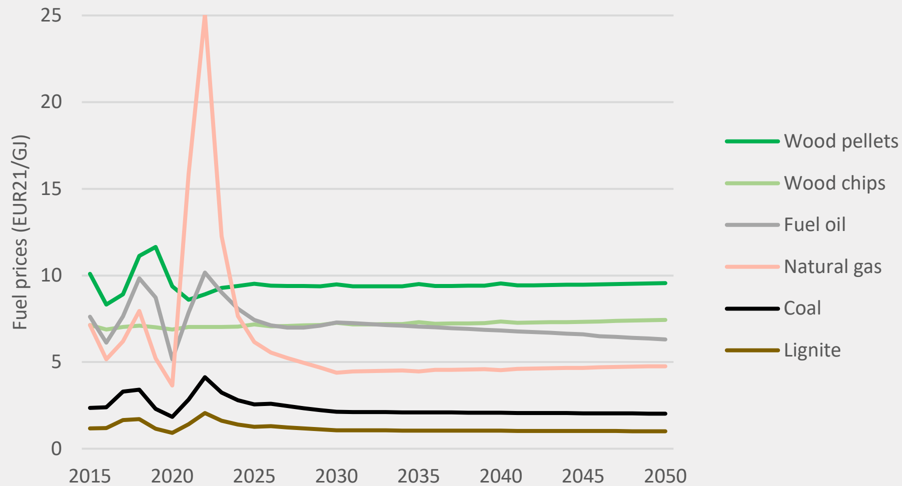




Average captured price

EUR/MWh	2030	2040	2050
Investment run	20,7	30,0	28,3
Weekly run	23,4	30,2	31,3
Hourly run	22,8	31,6	30,9

Power price driver - fuel and CO_2-prices

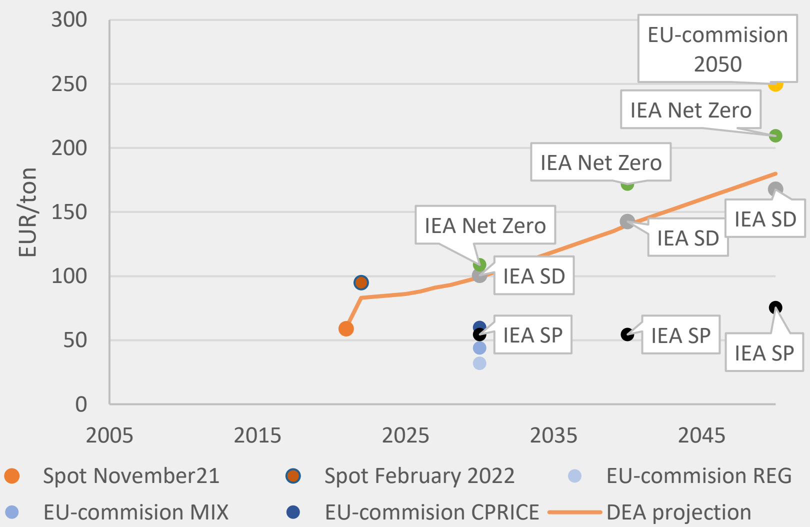


Fossil fuel prices based on the sustainable development scenario from the International Energy Agency's World Energy Outlook 2021 for 2030 and 2040. For 2021, historical prices are used, but due to the nature of very high gas prices in 2021 any decision performed by the model have been disregarded and reset in the following simulation. Between 2021 and 2030 prices are projected to converge from forward prices to the IEA's projections.

Historically, the IEA has underestimated technological progress. Choosing the the Stated Policies Scenario, would likely lead to the underestimation of cost competitiveness of RE technologies, and therefore fuel price estimates in the high range. The Paris Agreement and the European Green Deal further strengthen the argument for using the sustainable developments scenarios.

As one of the drivers for the green transition, the CO_2 price is assumed to grow rapidly in the coming 30 years. Towards 2030, levels of 100 €/ton are assumed, based on current market trends and a projection from the Danish Energy Agencies KF22 assumptions currently in public hearing. Based on the growth trends in the KF22 assumptions an annual growth of 4 €/ton is assumed towards 2050. The projection matches roughly with IEAs projections in the sustainable development scenario.

CO_2 is a commodity where supply and demand is heavily dependant on political decisions and other developments and sensitivity analyses are essential. However, the importance for the long term electricity prices decrease over time.



Sources: IEA (2021). World Energy Outlook 2021. Shown prices include transport cost to power plants.

Comparison of capacity scenarios

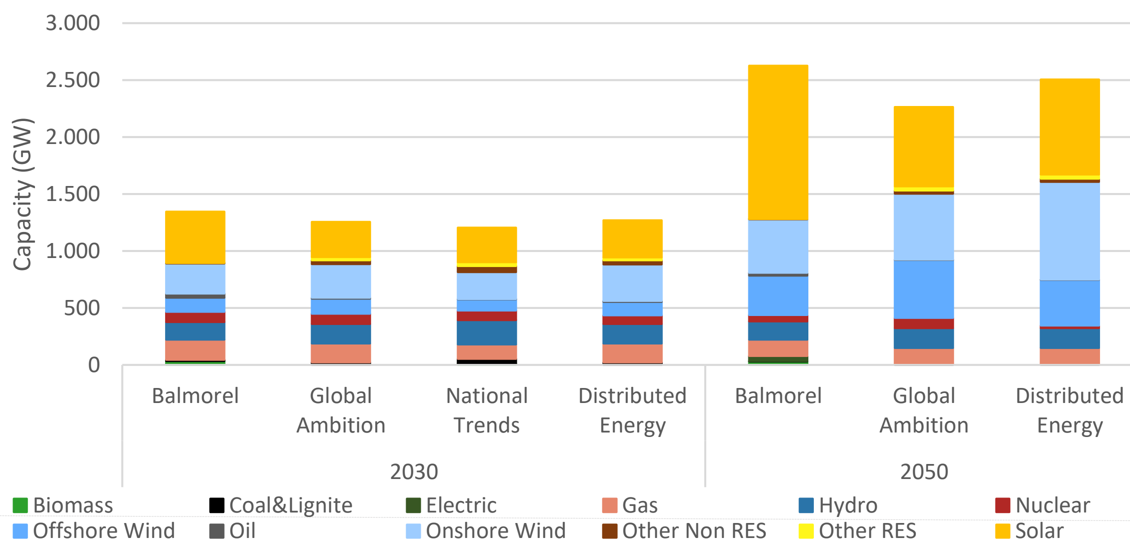
TYNDP PROJECTIONS

Generation capacity

Balmorel shows fast deployment in the short term and high deployment of solar power

Low cost on LCOE for solar power lead to high deployment rates, surpassing those of the TYNDP-scenarios. In the short term increased solar capacity (40-50%) leads to higher renewable shares and some replacement of wind capacity (10% below Global Ambition, but still above National Trends). RE-shares are at around 75% in the Balmorel-scenario in 2030, and 93% in 2050.

In the long term solar capacity is 60-90% higher than TYNDP scenarios, while wind deployment is 25-35% lower than TYNDP-scenarios. Capacity differences for wind are to some extent offset by higher average full load hours in the Balmorel model – both within regions as well as a result of changes in geographical wind power distribution.

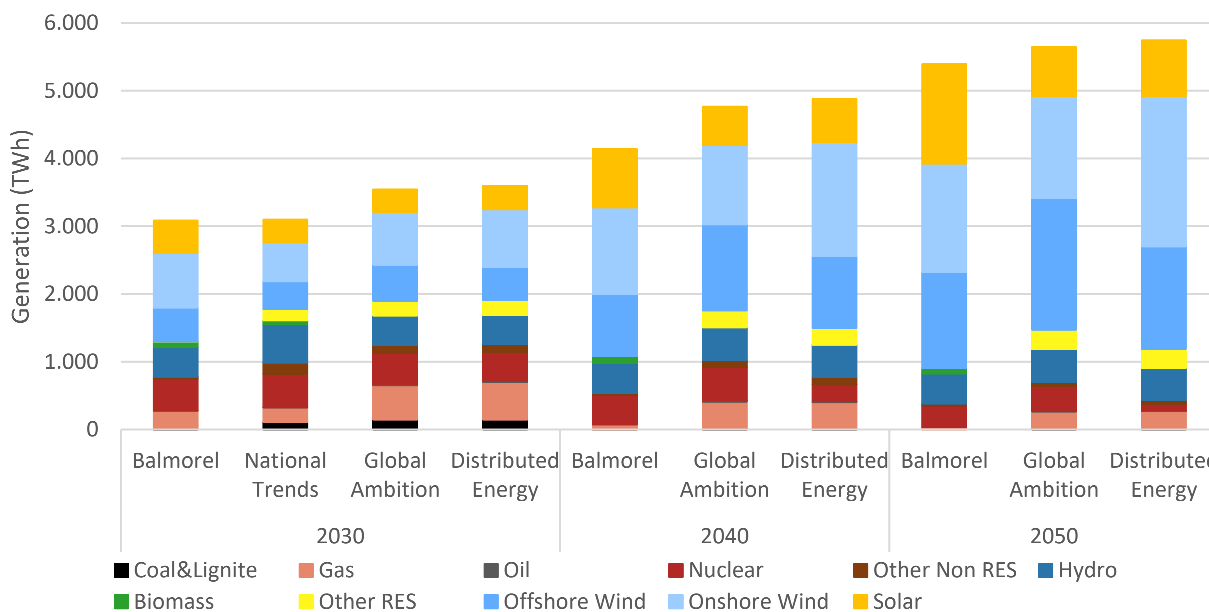


Electricity generation

Higher shares of variable renewable generation compared to ENTSO-E scenarios.

Higher deployment of solar power and higher average full load hours for both onshore and offshore wind increase the share of variable renewable generation compared to ENTSO-E scenarios in the short term.

In the long term, the additional generation from solar power in the Balmorel scenarios alters the relative division between wind and solar power compared to ENTSO-E scenarios. Total levels of wind and solar power in 2050 are 8% above Global Climate Action and 2% below Distributed Energy. Contribution from gas and other renewables in Balmorel scenarios is lower than in ENTSO-E scenarios.



Limits for buildout of renewables

Many European countries face challenges for deployment of wind and solar power onshore due to local resistance and planning processes. Also going forward to 2050, we believe that a pure technical assessment of the technical potential for buildout of onshore wind and solar power will not reflect realistic scenarios. However, realisable levels are hard to predict and are subject to significant uncertainty. For Balmorel-scenarios, the following assumptions on maximum buildout levels have been applied:

- For solar power: 1,5% of the available agricultural land and unused areas can be used for solar buildout.
- For onshore wind: Assumed a maximum limit of 125 GW onshore wind in Germany in 2050 – a country with relatively strong historical buildout of onshore wind, and thus experiences with local opposition. 125 GW corresponds to an average net buildout rate of 2,5 GW/year between 2020 and 2050. For other countries, this buildout rate has been scaled by the estimated technical onshore wind potential and multiplied by 75% to arrive at estimates for the total potential by 2050.

Exception apply, when detailed sources are available. For Denmark, a limit of 5,8 GW onshore wind has been applied, based on estimates on earlier political targets of limiting the total amount of wind turbines in Denmark.

Recent developments in the European Energy crisis could facilitate stronger deployment rates for wind and solar power and challenge the above mentioned maximum limits.

Onshore wind buildout

Towards 2030, the onshore wind buildout is lower in Balmorel scenarios compared to the hightes TYNDP numbers, while reaching similar generation numbers. In many countries, minimum buildout levels (based on national trends scenario) are binding.

Towards 2050, total buildout is lower than in TYNDPs distributed energy scenario, but comparable to levels in the global ambition scenario. In this timeframe, assumptions on maximum feasible buildout levels are limiting the deployment, and thus levels of the Distributed Energy scenario are not achievable.

		Balmorel	National Trends	Global Ambition	Distributed Energy
Capacity (GW)	2030	265	235	295	321
	2050	470		579	856
Generation (TWh)	2030	808	576	779	850
	2050	1.601		1.506	2.220

	2030		2050	
	Balmorel	TYNDP	Balmorel	TYNDP
Austria	9	11	9	34
Belgium	6	6	7	13
Czech	4	7	10	26
Denmark	6	8	6	16
Estonia	1	2	11	3
Finland	12	14	25	54
France	48	61	73	174
Germany	80	82	113	176
Great_Britain	27	41	55	128
Italy	22	31	33	78
Latvia	0	3	10	4
Lithuania	2	5	6	14
Luxembourg	0	0	0	0
Netherlands	10	8	11	18
Norway	6	8	12	22
Poland	14	13	57	38
Sweden	17	22	30	55
Switzerland	0	1	1	2
Total	**265**	**322**	**470**	**856**

Legend	Minimum level enforced
	Maximum level binding
	Installed capacity not bound by limits
	Maximum capacity of the TYNDP-scenarios

Offshore wind buildout

Towards 2030, offshore wind buildout is slightly lower in Balmorel scenarios compared to TYNDP. However, in most region, the buildout is defined by the minimum requirement based on the National Trends scenario.

Towards 2050, total buildout is lower than in TYNDPs Global ambition scenario, but comparable to generation levels of the Distributed Energy scenario. The levels in the Balmorel scenario are mostly defined by model optimisation, since neither minimum or maximum levels are binding. Exceptions are France and Belgium, where maximum limits are binding, and the Baltic Sea, where minimum levels are binding.

		Balmorel	National Trends	Global Ambition	Distributed Energy
Capacity (GW)	2030	122	98	133	119
	2050	346		506	401
Generation (TWh)	2030	502	409	533	488
	2050	1.414		1.942	1.512

	2030		2050	
	Balmorel	TYNDP	Balmorel	TYNDP
Austria	0	0	0	0
Belgium	4	5	6	8
Czech	0	0	0	0
Denmark	8	12	26	52
Estonia	0	1	0	2
Finland	2	9	2	17
France	9	18	61	90
Germany	30	26	50	80
Great_Britain	40	36	86	128
Italy	5	3	21	15
Latvia	1	1	1	2
Lithuania	1	1	1	3
Luxembourg	0	0	0	0
Netherlands	15	12	75	59
Norway	0	3	5	14
Poland	6	6	6	24
Sweden	1	3	7	12
Switzerland	0	0	0	0
Total	**122**	**135**	**346**	**506**

Legend	Minimum level enforced
	Maximum level binding
	Installed capacity not bound by limits
	Maximum capacity of the TYNDP-scenarios

Solar PV buildout

Towards 2030, buildout of solar PV is higher than any of the TYNDP scenrios. While minimum levels are binding in Germany (based on the governments targets) a few other regions show levels above minimum buildout or even bindings from maximum levels.

Towards 2050, total buildout is almost double of the buildout in TYNDPs Global ambition scenario. In all countries, buildout is either optimised by the model or limited by maximum restrictions, showing that assumptions on potential are defining the buildout levels.

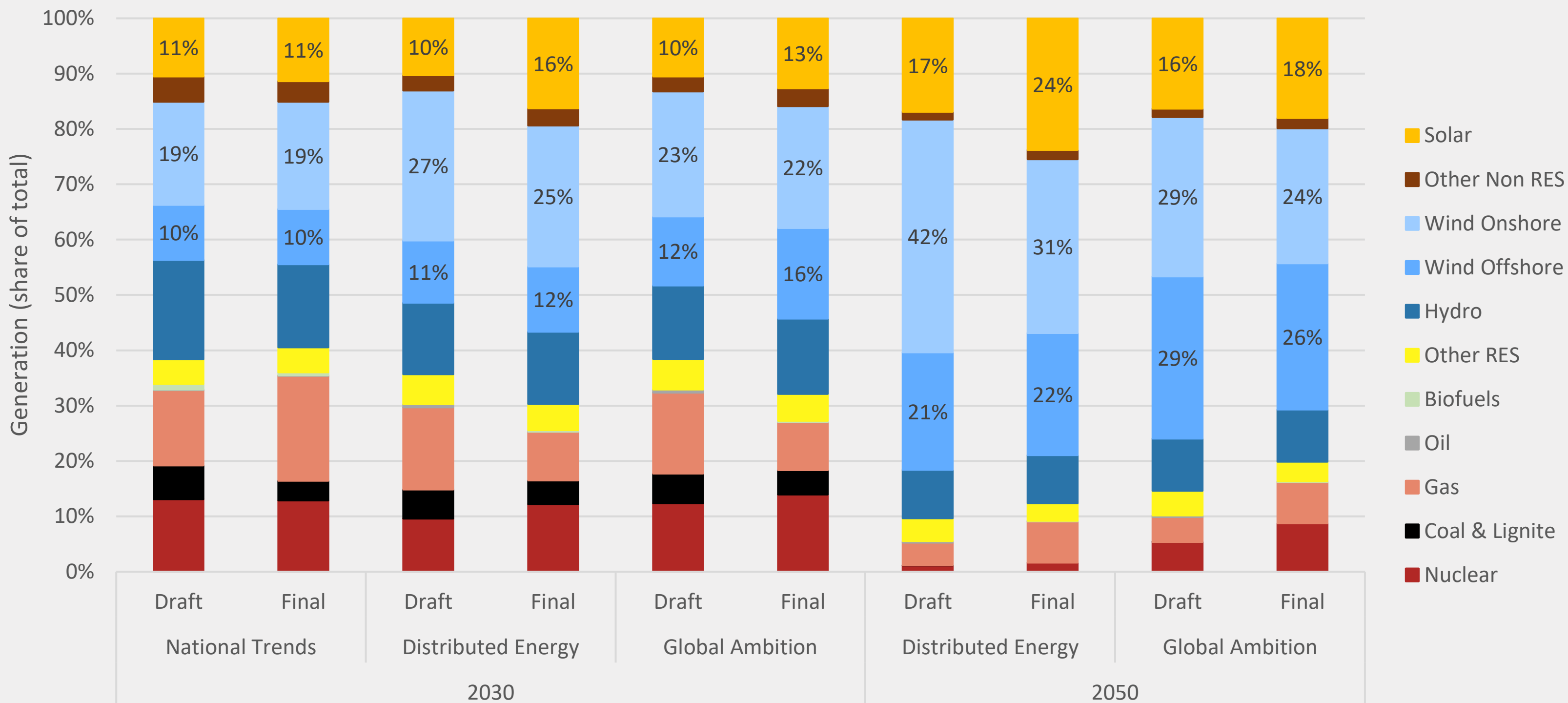
		Balmorel	National Trends	Global Ambition	Distributed Energy
Capacity (GW)	2030	450	305	311	326
	2050	1.343		697	832
Generation (TWh)	2030	479	337	331	344
	2050	1.471		725	823

	2030		2050	
	Balmorel	TYNDP	Balmorel	TYNDP
Austria	15	12	46	24
Belgium	14	17	24	25
Czech	6	7	46	20
Denmark	7	7	33	11
Estonia	0	1	6	3
Finland	1	5	13	16
France	80	43	381	196
Germany	150	96	212	124
Great_Britain	23	29	151	95
Italy	72	57	217	130
Latvia	0	1	2	3
Lithuania	1	3	3	6
Luxembourg	0	1	1	0
Netherlands	27	42	27	51
Norway	1	1	2	0
Poland	36	18	143	85
Sweden	5	18	19	33
Switzerland	9	10	16	11
Total	**450**	**368**	**1.343**	**832**

Legend	
	Minimum level enforced
	Maximum level binding
	Installed capacity not bound by limits
	Maximum capacity of the TYNDP-scenarios

Final TYNDP-scenarios

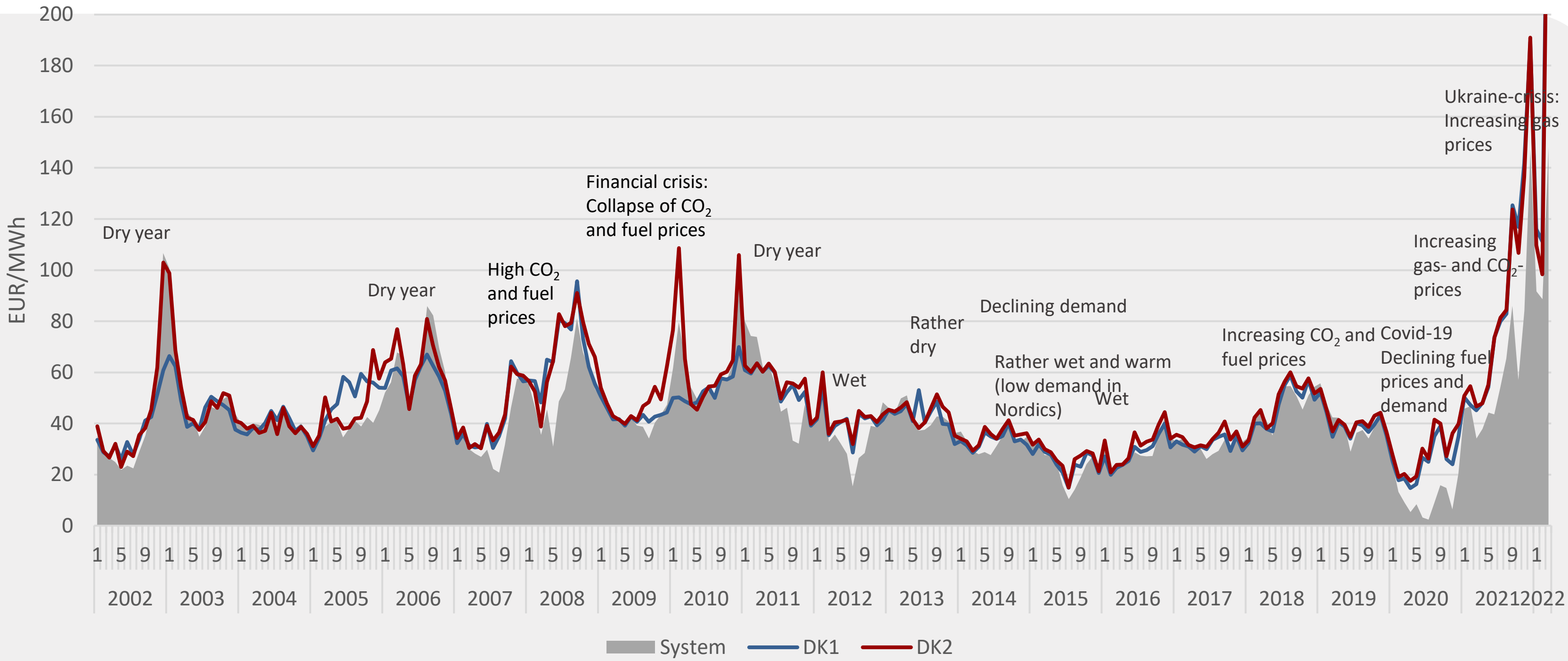
In April 2022, ENTSO-E published the final version of the scenario dataset. The results of the final dataset are not included in the modelling or the comparisons. However, comparing the draft and final dataset shows a move towards higher shares of solar power, which was one of the main differences to the Balmorel results. Total contribution from wind & solar power has not increased, and the additional solar power is replacing mainly onshore wind.



Statistical Review

ELECTRICITY MARKET

Historical Spot Price in Denmark



Source: Energinet and ENSTO-E transperancy platform. Real 2021-prices.

Hydrological conditions have a significant impact on the Nordic price formation.

- In dry years, Sweden, Finland and Norway increase net-imports to compensate for lack of hydro generation.
- In wet years abundance of hydro allows plant owners to lower the prices of their supply offers.

Besides the availability of hydro power, the main historic driver of short-term movements in the power price are fuel prices and the price of CO_2.

Average Prices by generator type in Western Denmark

Captured prices vary by generation technologies

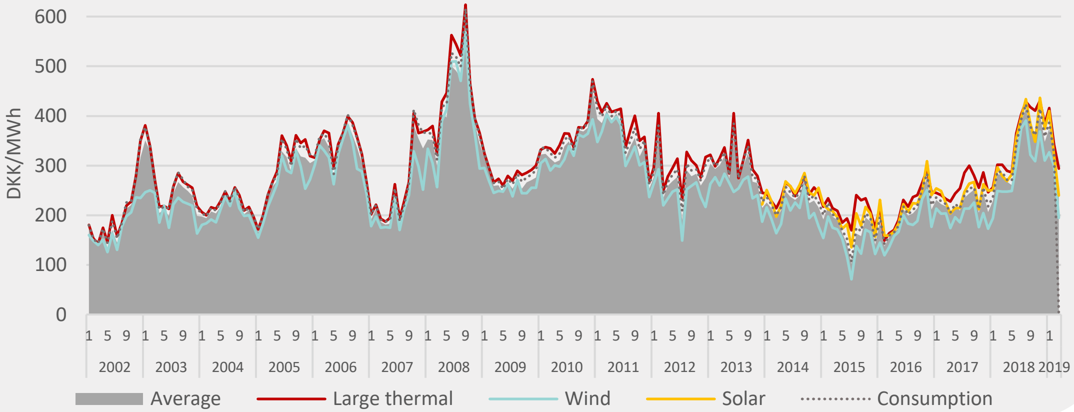
Simple time-weighted averages of Nord Pool spot prices provide a first indication of the market potential for various generation technologies to capture prices, but since wholesale prices vary hour-by-hour, average quarterly and yearly prices differ between technologies.

- Dispatchable generation with high short-run marginal costs capture higher (albeit fewer) prices on average.
- Technologies with low short-run marginal costs capture lower prices but have more operating hours.
- Intermittent generation generally captures lower prices, particularly when the resource (e.g. wind) is simultaneously abundant across a wide region. Solar power generally has an advantage of coincidence between generation and high demand. This will erode with a significant increase in penetration.

Western Danish power generators are primarily large power stations, decentralised CHPs and wind turbines. Recent years have also seen an increase in distributed solar PV.

Since 2002, monthly prices captured by generators in Western Denmark have relative to the monthly average hourly price been:

- Central power stations +8%
- Wind power -9%
- Solar power +8%
- Consumption +4%



Source: Based on data from Energinet.dk. Nominal prices.

Power price modelling

THE BALMOREL MODEL

BALMOREL
Energy system model

Balmorel energy system modelling tool

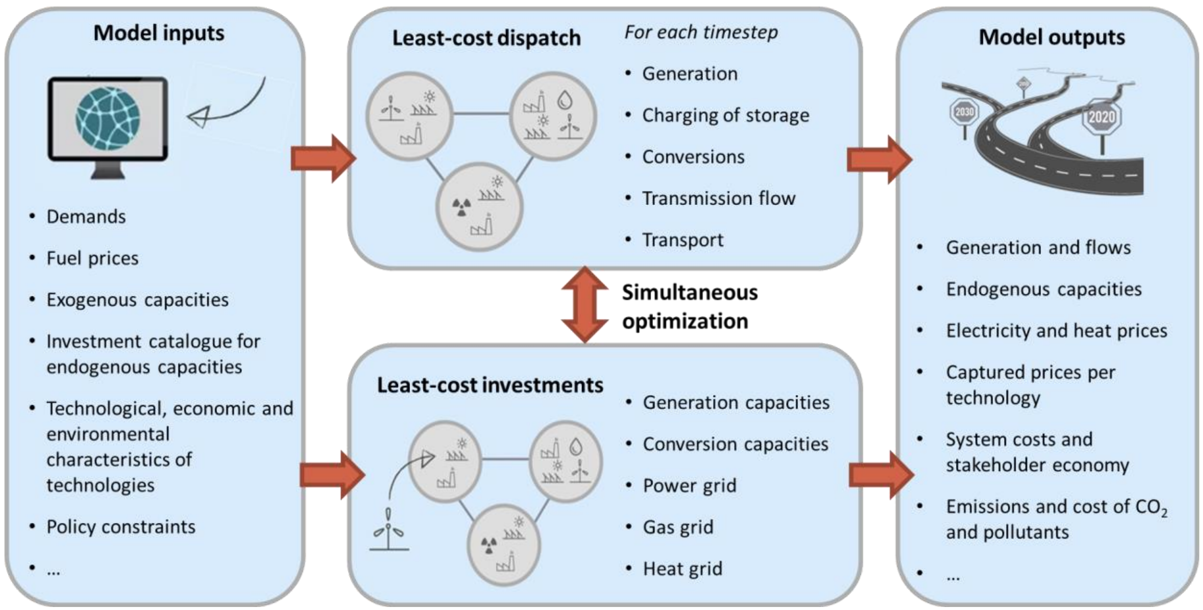
Model developed to support **technical and policy analyses** of power systems.

Optimization of **economical dispatch and capacity expansion solution** for the represented energy system.

Characteristics: open-source, customizable, scalable, transparent

Balmorel is a fundamental partial-equilibrium model of the power and district heating system. The model finds least-cost solutions based on assumptions such as the development of fuel prices, demand development, technology costs and characteristics, renewable resources and other essential parameters.

The model is capable of **simultaneous investment and dispatch optimisation**, showing optimal solutions for **power generation and interconnector capacity, dispatch, transmission flow and electricity prices**. Prices are generated from system marginal costs, emulating optimal competitive bidding and clearing of the market.

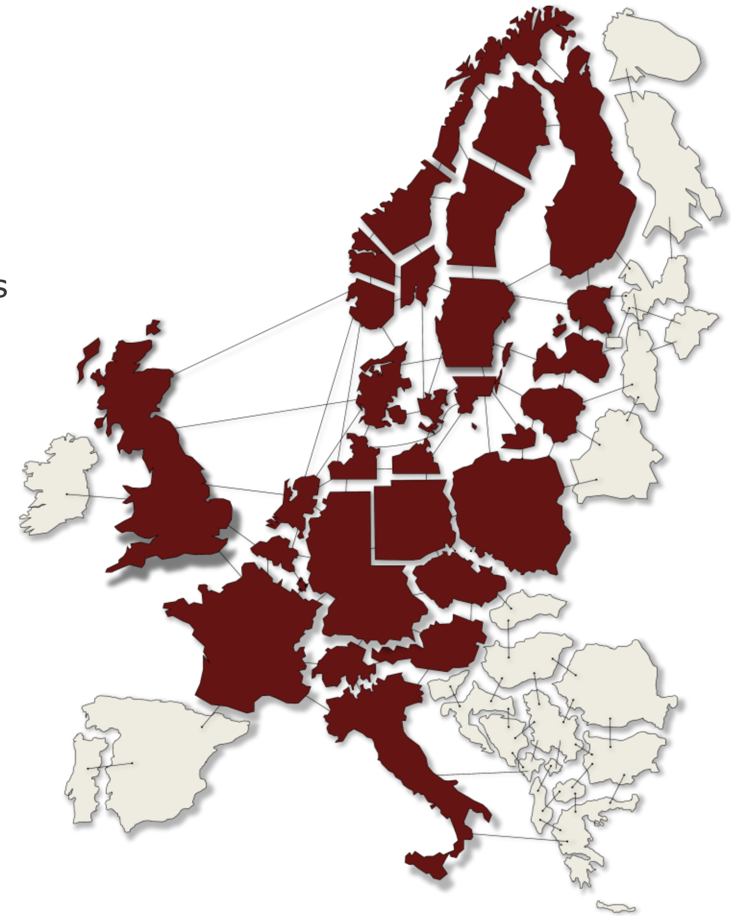


Model dimensions

Main evaluation measures
- Power prices and market values
- Generation & capacity balances
- CO2 and pollutant emissions
- Socio-economic system costs

Temporal scope
- Selected optimization years
- Time aggregated investment optimization
- Hourly dispatch optimization

Geographical scope
- Scandindavia (bidding zones)
- Germany (4 regions)
- Baltics
- Central Europe, UK and Italy



Variable renewable generation

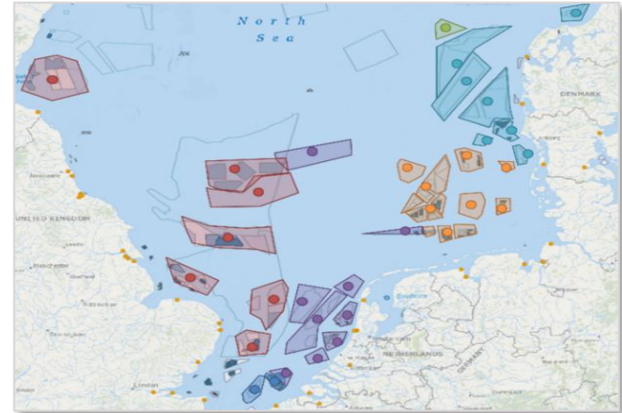
Generation profiles from wind and solar power influence power price patterns and captured prices – depending on generator type and geography

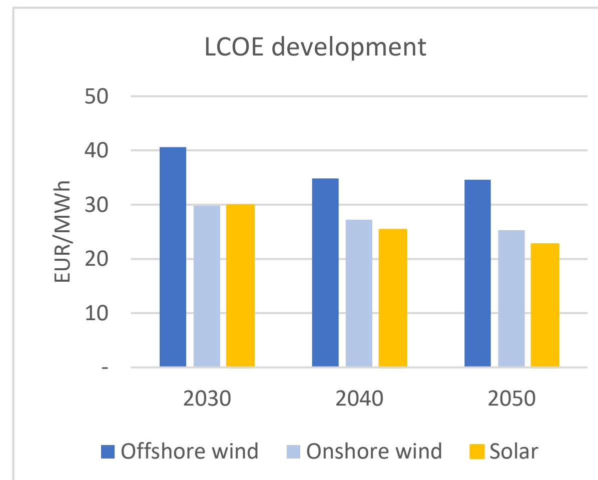
- **Generation profiles** for wind and solar power are based on reanalysis-weather data, ensuring consistency across the modelling region

- Wind turbine and solar panel **technology developments** and their effect on generation profiles are considered

- Future offshore deployment in different countries is based on **site-specific modelling** and includes national plans

- Potential for buildout of onshore wind and solar PV is **dependent on local conditions and public acceptance**, and therefor subject to significant uncertainty, which a pure technical modelling of resource potentials would not account for.

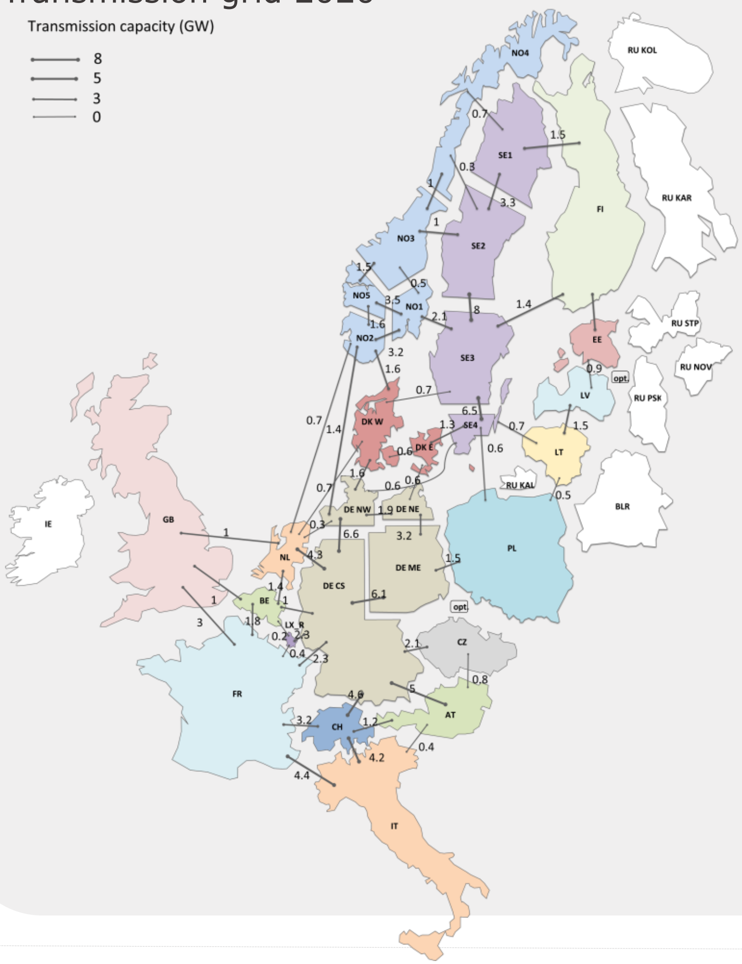




LCOE shown using WACC of 5% and an economic lifetime of 25 years. Actual cost are site dependent. Development shown shows LCOE for modelled buildout in Denmark.

Representation of the international power market

Transmission grid 2020



Modelling power transmission and price areas

Development in the international and interconnected power and energy system has significant implications on the development in any singular price area.

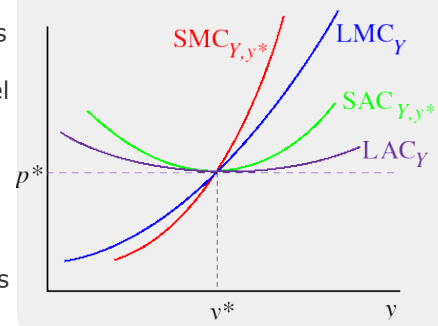
- The analysis includes calculations in the regions shown in color on the map. The included countries are hereafter called the 'Entire system'.
- Individual countries are subdivided into regions, between which the most significant power transmission congestions occur.
- In the Nord Pool countries, these regions coincide with the price zones in Nord Pool.
- The German power market has one price zone (together with Austria), in spite of congestions in the internal grid. In the model however, Germany consists of four price zones interconnected by transmission links. The model takes the internal bottlenecks into account in order to have a better representation of the actual operation of the German power system.

Electricity price and marginal production costs

Balmorel output includes marginal values of each of the many constraints in the model. The marginal value of the equation ensuring that power supply is equal to power demand in each power price regions at each point in time, can be interpreted as the wholesale electricity market price. This relies on the assumption of perfect competition. The level derives from the equilibrium with the marginal production costs, which emulates market actors' incentive for bidding in the market, as well as the market clearing mechanism.

If the model is allowed to make new investments, the prices which arise satisfy equilibrium conditions with the long-run marginal costs of the capacity installed by the model. Thereby, at certain times the prices will exceed the short-run marginal costs.

Model result interpretation



- Calculations with investments
  - Power prices in equilibrium with long-run marginal costs of production.
- Calculations with given capacities
  - Power prices in equilibrium with short-run marginal costs of production in at any time.

In a market with adequate demand response or sufficient variable cost intensive technology options, the long-run and short-run marginal costs converge towards the same equilibrium.

Investment runs to hourly prices

- Power prices in model runs without endogenous investments are typically lower than runs with endogenous investments, assuming the generation capacity mix is the same. Thereby, it is possible to get model results with lower prices, but with the same overall costs.
- Model determined investments in generation and/or transmission capacity can be transferred to a model without endogenous investments. The two models will result in the same dispatch and only slightly different power prices all else being equal.
- Endogenous investments are computationally taxing and therefore it is a common approach to determine the capacity mix first using an aggregate representative representation of time and transfer the capacity mix to an hourly simulation without investments.

Hydro power

Hydro power reservoirs work as an energy storage. Bidding of hydro generation capacity depends on the expectations for future earnings possibilities, which thereby creates and equilibrium over time.

Linkage options for investment and hourly simulations:

- Fixed generation quantity: The price equilibrium for hydro determined in the investment run is shifted. This may consequentially yield an prices which cannot be said to represent the long-run equilibrium expectation.
- Fixed bidding prices for hydro power: This may result in minor changes in hydro power output, but the prices are more in line with the long-run equilibrium.

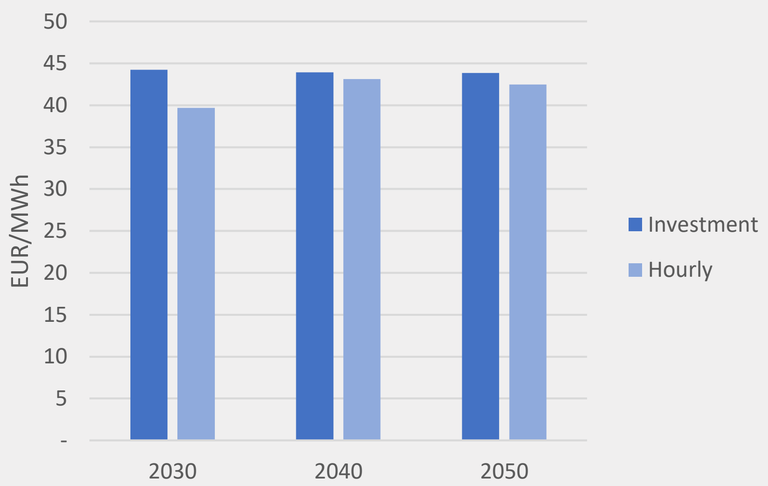
Long term equilibrium prices

Modelling of the European power market is based on the assumption, that the Energy only market will be the main driver for investments. Therefore, market driven investments are assumed to be able to recover their cost from power market income, and subsequently the long term market prices are closely linked to assumptions on LCOE for wind and solar power, which make up 85% of the market in 2050.

However, investment optimization in power market modelling is computationally heavy, and therefore based on aggregated time resolution. While full recovery of cost for new investments is ensured in the investment optimization, market prices and thereby market income can differ slightly in the subsequent hourly simulations.

Differences in average prices are especially related to cost recovery for peak generation investments, which only affect wind captured prices to a low degree. In practice, business cycles will lead to year with both lower and higher prices, than the estimated averages.

Apart from the results shown here, the price forecast results are based on the hourly simulations.



Detailed model simulation setup

- Investment run (26 seasons, 12 timesteps each)
  - Investment optimization, full foresight entire year
- Weekly run (52 seasons, 12 timesteps each)
  - Dispatch optimisation, full foresight entire year, allocation of hydro generation and storage to weeks
- Hourly run (52 seasons, 168 timesteps each)
  - Dispatch optimisation, full foresight within one week

Power transmission capacities

Transmission grid expansion based on TYNDP 2018 and 2020 until 2030. After 2030, transmission expansion is subject to model optimization.

Overall development
Between 2020 and 2030 the transmission system is expanded by 55% according to ENTSO-Es plans. Between 2030 and 2040, further buildout is restricted to 3 GW pr. transmission corridor.

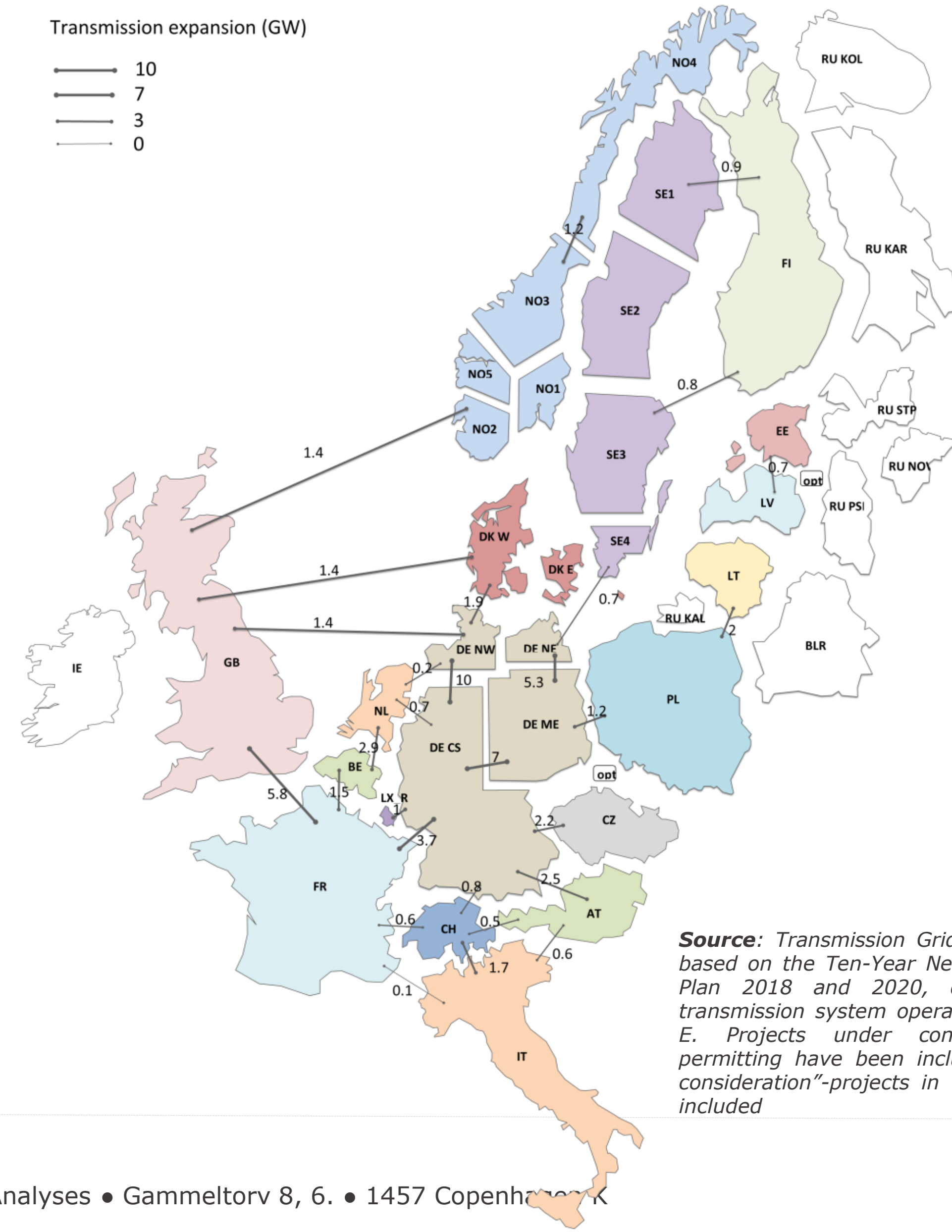
Significant changes for Denmark

Viking Link: 1.4 GW (DK-GB) by 2023

German internal grid: based on the TSOs' grid development plan (NEP2017), scenario B.

Energi-Ø Bornholm: Adding 1 GW transmission capacity between Eastern Denmark and Germany

Input transmission expansion between 2020-2030



Source: Transmission Grid developments are based on the Ten-Year Network Development Plan 2018 and 2020, developed by the transmission system operators within ENTSO-E. Projects under construction and in permitting have been included, while "under consideration"-projects in the TYNDP are not included

Core assumptions

PROJECTION OF PRICE DRIVERS

Future electricity prices: main drivers

- ***How will fuel prices develop?***
- ***What climate targets will the EU and its member states pursue beyond 2030?***
  - ***How will the EU ETS system develop?***
  - ***What role will RE subsidies play in the market?***
- ***How will technological development influence power markets?***
  - ***Cheaper solar PV and offshore wind***
  - ***New storage technologies***
  - ***Flexible electricity demand and smart grids***

Secondary drivers

- General development in electricity demand
- Grid development and market integration
- Development of nuclear power, particularly in Sweden and Finland
- Acceptance of CCS technology
- Introduction and design of capacity mechanisms

In addition, electricity prices are subject to the impact of weather variations, in particular variations in hydro inflow, wind and solar production and business cycles affecting fuel prices and electricity demand.

Assumptions for main drivers

The base case is our best guess of the power system development towards 2050.

A main driver for the base scenario is the reform of the ETS-system towards 2030 and the suggested European vision for a carbon neutral energy system in the EU in 2050.

Key factors	Our best estimate
How will fuel prices develop?	Climate policies and technological development will dampen the demand for fossil fuels. Hence, current forward prices will converge toward the IEA's Sustainable Development scenario from World Energy Outlook 2021
What climate targets will the EU and its member states pursue for 2030 and beyond?	The EU will pursue an active climate policy, also beyond 2030. Towards 2050 ambitions of 90% reduction of greenhouse gas emissions are assumed.
Will renewable energy technologies mainly be supported through subsidies or indirectly by means of a carbon price?	The future climate policy will involve a combination of renewable energy support and carbon pricing in the short term. Beyond 2030 carbon pricing will be the main driver. Also in the shorter term (2020-2025) onshore wind and solar power will be competitive without subsidies at the best sites.
How will technological development influence power markets? • *Cheaper onshore and offshore wind as well as solar PV* • *New storage technologies* • *Flexible electricity demand and smart grids*	Investment cost of renewable energy technologies will decrease to the extent that their production profile and local acceptance become the major barrier for further market uptake. New storage technologies and smart grid technologies will not have major deployment towards 2030, but can gain increasing importance towards 2050. The main source of technical and economic data for new plants, both for the electricity and the district heating sector, is the Technology catalogue from the Danish Energy Agency.

Danish policy drivers

While the power price in Denmark is heavily dependent on international market development, national policies influence both demand and generation.

Key factors	Our best estimate
How will demand develop?	The governments target of reducing greenhouse gas emissions by 70% will lead to ambitious electrification measures, increasing national demand[1]. However, the 70% target is ambitious, and the exact measurements to achieve it, are yet to be defined.
What new types of demand will be introduced?	Four major types of new demand are assumed. • Electrification of transport • Electrification of individual heating and phaseout of natural gas and oil boilers. • P2X • Industrial electrification
Electricity and district heat	A number of policies are assumed for the national electricity and district heating sector • Coal phaseout by 2030 • Expansion of offshore wind capacity • Introduction of energy Islands • Introduction of PtX

[1] The development includes both fast electrification pathways and application of new technologies and is therefore very uncertain by nature. Whether or not the assumed development within power demand will support a 70% reduction pathway will also depend on other sectors.

Capacity investments and decommissioning

The capacity in the power system develops according to the least cost optimization of the Balmorel model. The model invests in generation capacity if it is profitable, and decommissions capacity if it is not, from a power system perspective. The model both invests and decommissions myopically, i.e. only based on the information of the given year, not taking into account estimates for the future. This applies to parameters such as fuel and CO_2 prices.

- **Investments:** The model invests in a technology when its projected annual revenue can cover all costs including capital costs, fixed O&M.
- **Decommissioning:** The model decommissions a technology when the revenue can no longer recover fixed O&M. Exogenous capacity is kept constant (except if better data for expected decommissioning year is available) unless it is decommissioned by the model.

The model is not allowed to invest and decommission freely, however, as there is additional information available on capacity developments and technology restrictions from a variety of sources. The main restrictions include:

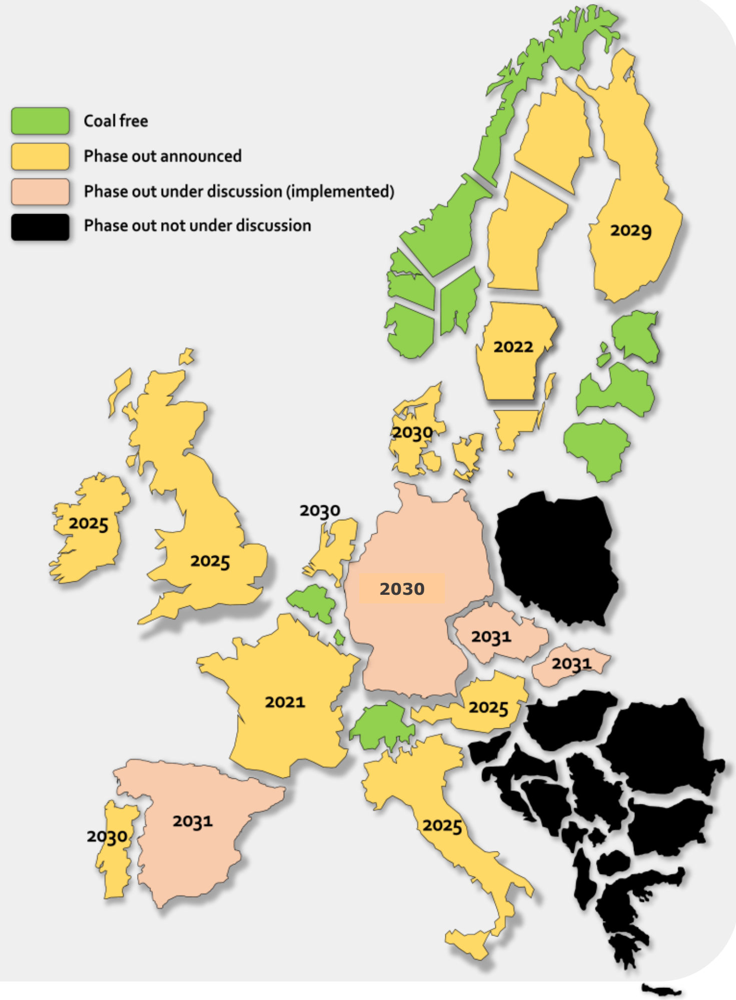
- A minimum roll-out of RE capacity in the short- and medium term.
    - Based on best estimates from a variety of sources.
    - The model is allowed to invest in RE above enforced minimum levels.
- A maximum roll-out of RE capacity
    - Maximum deployment of solar power and onshore wind will not be limited by the technical potential, but local acceptance and planning constraints. Therefore maximum limits are used to represent limitations in pace and maximum acceptable levels.
- Restricted fossil fuel investments
    - No new coal fired capacity in Europe (except Greece and Poland) after 2020 as outlined by Eurelectric.
- No nuclear investments. Instead, nuclear capacity developments are fed into the model based on best estimates.

Exogenous capacity development

Development of the existing generation capacity is subject to uncertainty. Similar to new investment, the lifetime of existing capacities is subject to economic optimization and thus dependent on the development of electricity prices. However, other factors, which are harder to reflect in model optimizations also play a role: National policies, environmental legislation on emissions effectively ruling out older power plants; various national subsidies to support certain power plants or type of power plants due to either concerns about the security of supply or national priorities (e.g. importance of power plants for regional economy and labour), optimization of fixed cost as a result of changing operational patterns.

The overall approach to the development of existing capacities is, that known and certain phase outs are implemented exogenously, while the remaining capacity is held constant, and the lifetime is subject to economic optimization (power plants have to recover fixed cost). Some exceptions are mentioned below. Wind and solar capacity have relatively low fixed operational cost, and are therefore assumed to be decommissioned after the end of the technical lifetime.

Countries	Development
Denmark	Coal, oil, biomass gradually phased out according to expected development
All countries	Coal phaseout according to announced or discussed phaseout-plans (see map). Existing wind and solar power phased out after end of technical lifetime.



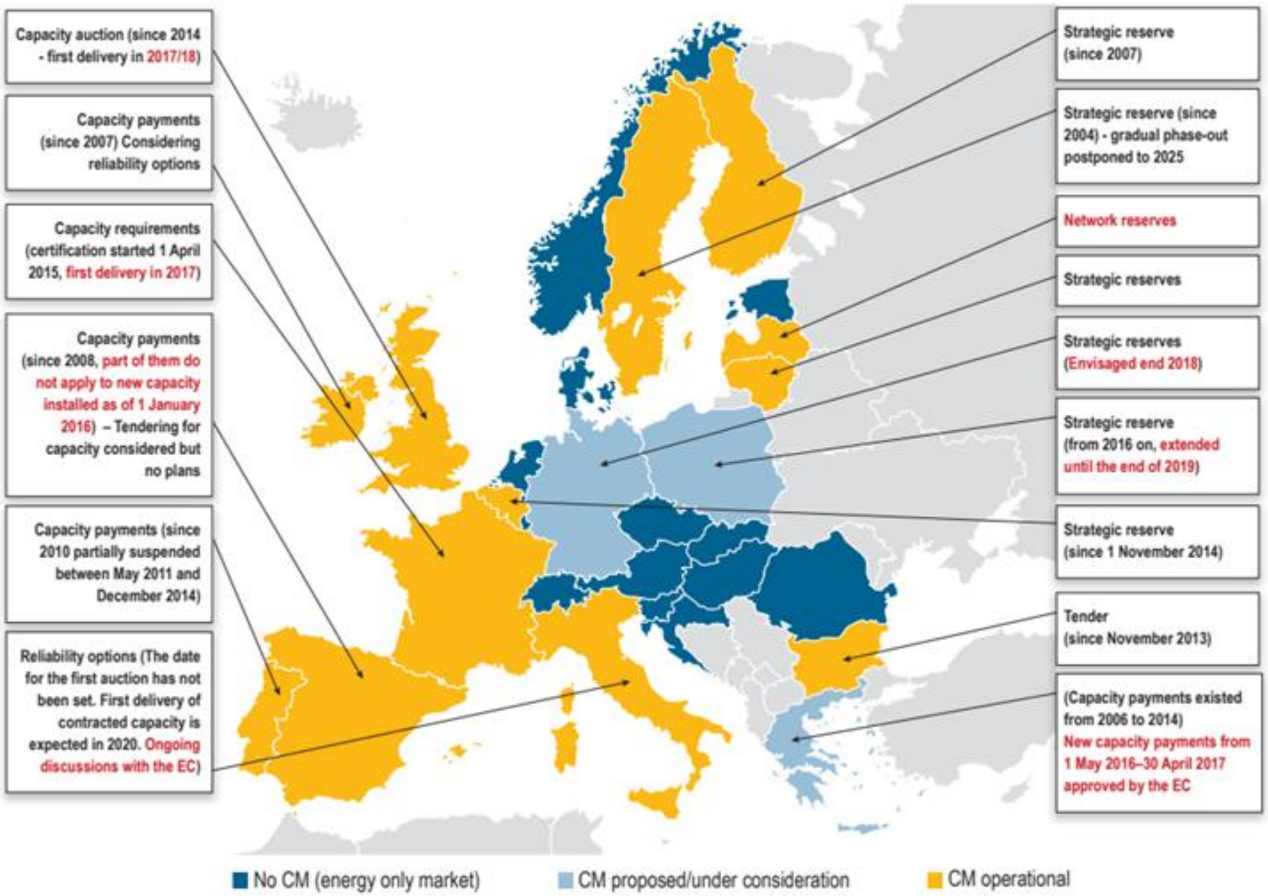
https://beyond-coal.eu/wp-content/uploads/2022/01/Copy-of-overview-of-national-coal-phase-out-commitments-13-January-2022.pdf

Capacity mechanisms

Due to a combination of issues such as the integration of high shares of renewables and an ageing electricity infrastructure, some doubt that current market structures provide sufficient incentives for investments in new power plants. As a consequence, several countries have already introduced, or plan to introduce, capacity mechanisms in order to introduce a payment to owners of generation (or demand side response) capacities in addition to those offered by the current electricity markets.

The figure to the right gives an overview of existing and planned capacity mechanisms. The Commission last year approved capacity mechanisms in Belgium, France, Germany, Greece, Italy and Poland. http://europa.eu/rapid/press-release_IP-18-682_en.htm, February 2018.

http://europa.eu/rapid/press-release_MEMO-18-681_en.htm



Source: ACERS's Market Annual Report on the Results of Monitoring the Internal Electricity and Gas Markets in 2016 (ACER, 2017). In February 2018 the EU Commission approved a market wide capacity mechanism for Poland.

Fuel and CO_2 price methodology

Competing views of fuel prices

Forward markets

Market prices are true to the extent that market participants engage in transactions at quoted prices. Forward markets quote prices several years into the future, however there is very limited trading just a few years out. This means that beyond, say five years (depending on the particular commodity), the market price is not an expression of what buyers and sellers expect to eventually pay. In the short-term, however, the forward markets are more liquid, meaning that it is with high likelihood that a transaction partner can be found to trade near the quoted market price.

Long-term equilibrium

The long-term development of fossil-fuel prices are driven by underlying factors such as the global macroeconomic development, technological development and development of resources. While highly uncertain, these factors are best taken consistently into consideration through energy system models, which calculate long-term equilibria. While we do not trust the accuracy of these projections, there is consistency between their underlying assumptions which provides an understanding of their bias.

Convergence of views

In general, the view is adopted that in the short-term the markets are right. In the long-term, the global energy system models are more likely to be right. Therefore, we adopt a gradual conversion between these views.