4 Appendix: details on the model, scenarios and sources

This document is a complement to the report *Energy Union Choices,* aimed at clarifying the assumptions behind the work performed. Its aim is not to be fully exhaustive but to help the comprehension of the methodology and of the data used. Some datasets are also available on the Energy Union Choice website[1] to complement the report and this appendix.

4.1 Model and optimization process

The exposed problematics were tackled by modelling the European gas and power system at a country-level granularity, meaning that each country is represented as a node, linked to other countries through pipelines and power interconnections. Thirty two countries are explicitly represented, including EU28 except Cyprus and Malta, as well as Switzerland, Bosnia, Serbia, Macedonia, Montenegro and Norway, which are part of the ENTSOs perimeters. While the European power system is considered isolated in itself, gas and LNG imports from major external commercial partners, such as Russia, Algeria, Libya, Ukraine or Turkey, were taken into account in the gas model.

At each node, every gas and power demand and supply are represented at an aggregated level. At every time step considered, the total supply in gas (respectively power) is directly balanced with the total demand in gas (respectively power), taking into account the flows between nodes. National internal market constraints and limitations are not represented. Assets considered in the model are summed up in the following tables. More details on their model is given in the next sections.

Table 1: Assets modelled in the gas system

	Supply	Demand
Gas System	LNG terminals Pipelines (imports) Storage/Reserve (withdrawal) Demand response (reduction of demand) Internal production	Internal demand Gas consumption for power generation Pipelines (exports) Storage (injection)

[1] http://www.energyunionchoices.eu

Table 2: Assets modelled in the power system

	Supply	Demand
Power System	**Thermal generation:** Nuclear, Coal, Lignite, CCGT, OCGT, other thermal fleets **Renewable generation**: Wind onshore, Wind offshore, Solar PV, Hydro Run-off-river, Biomass, other renewables (including Tidal, Geothermal energy) **Hydro storage:** Seasonal storage**,** Pumped storage (generation) Interconnections (imports)	Internal demand Pumped storage (pumping) Interconnections (exports)

The simulations performed aim at minimizing the overall cost of the system for the entire year, taking into account the operational costs of the system, that is to say, the series of actions among production, imports, cross-border exchanges and storage that allows to balance consumption and supply in every zone, at each hour, at the lowest total cost (including fuel costs, CO2 emissions costs and loss of load penalties).

Equivalently, the energy market behaviour that is simulated is one of a perfect market, whose outcome is therefore supposed to be social-welfare maximizing. In a security-of-supply perspective, maximizing the social welfare can be assimilated to minimizing the global supply cost, under the constraint of meeting the energy consumption demand.

The model also allows to perform capacity expansion planning, as is done in section 2.2 of the report, where investments in LNG terminals, pipelines, storages, and power interconnections in the integrated approach, are optimized simultaneously to operation costs. In this case, installed capacities of these assets become variables of the optimization problem instead of inputs. A new infrastructure asset will then be built by the model only if its investment cost and the operating cost of using it, combined, are less than the costs of alternative options. Those can be: using already installed capacities and pay the associated operational cost only, investing in another asset and pay the correspondent investment cost plus the operational cost of using it, or failing to supply the demand (if already installed infrastructure are insufficient) and pay loss of load penalties. In this aspect, this model consists in establishing the best trade-off between investment costs and savings in operations cost (as previously described) induced by those investments.

4.2 Gas assets modelling

4.2.1 Consumption

Gas consumption is represented at an hourly time step for each node in the model. It includes two parts: the consumption of gas for power generation (G2P), and the consumption of gas for other usages.

Gas consumption outside of G2P is modelled as a contract of gas that has to be supplied to customers, respecting a daily consumption curve. It includes notably industry consumption and gas consumption for residential and commercial heating. The yearly volume that has to be provided depends on the scenario used. The consumption profiles are based on ENTSO-G data. Analysis of the dependence to temperature of these profiles have been performed to be able to generate adequate profiles for 50 years of temperature, thus correlated between countries. The standard and cold years were selected using among these 50 years.

Gas consumption for power is, depending on the simulation an input or an output of the model. In the gas-only simulations presented in section 2.1 of the report, gas consumption for power is an input characterized by an hourly profile. This hourly profile has been obtained from simulation of the optimal dispatch of the power system for the corresponding scenario. As the power consumption also depends on temperature, the gas consumption for power also depends on the considered year. In the joint gas and power simulations, presented in section 2.2.2 of the report, as gas-based power generation is optimized at the same time than gas and power dispatch, gas consumption for power becomes an output of the model.

In the integrated approach, **gas demand response** is modelled. In this case, 30% of the industry consumption, included in the gas consumption outside of G2P, can be switched to oil consumption, and thus not supplied with gas. This figure is a result of a study on existing oil back-up capacities in the industry, conducted by Element Energy**.** As scenarios do not provide details on the gas consumption across all sectors, it has been assumed that the share (excluding G2P) of gas consumption for industries is the same than today in % (source Eurostat).

4.2.2 Internal production

Internal gas production of represented countries is modelled as a constant gas injection over time, at nodes standing for producer-countries. The injection levels are set to the national capacities, which depend on the considered scenario. No cost is associated to that production. In this light, the model always prefers local gas production rather than imports from outside of Europe.

In the On track and Current trends scenario, production declines in almost all countries, including in the Netherlands and in the United-Kingdom which are the two main current

European producers. In the High demand scenario, it also decreases in most countries, but stays constant in the United-Kingdom due to the extraction of shale gas.

4.2.3 Gas imports and pipelines

Gas imports from countries outside of Europe are also considered in the model. Since those countries are not explicitly modelled, imports from there are represented as direct injections of gas to countries linked to the supplier. The annual imported energy volume is optimized and limited only by the existing capacity of the pipeline. Gas imports cost in €/MWh is based on scenario data.

Gas can be transferred between nodes of the model through **pipelines**. They have limited unidirectional capacities, which can be fully exploited all-year-long. The flow transiting through each pipeline at each time step is a result of optimization.

The pipeline capacity can also be optimized in the capacity optimization runs (section 2 of the report), with an investment cost of 59.8 k€/MW/100km for both new infrastructures and reinforcement, and 8% of this cost (4.7 k€/MW/100km) for reverse flows. A pipeline capacity of 1 bcm/yr would cost 73.8 million € (5.8 million € for reverse flows).

This data comes from calculations based on historic data for the US[2].

4.2.4 LNG terminals

LNG terminals in each country can also be used to supply part of the demand. In the model, an LNG terminal is a combination of a terminal, a storage facility and a converter. LNG imports are optimized and supposed constant during the whole year. A small storage capacity is present at each LNG terminal giving the three assets a small flexibility, allowing to increase the production temporarily if needed.

In the capacity optimization runs, LNG terminals can be built in every coastal country. The investment cost of 113 k€/MW has been used for both new LNG terminals and existing LNG terminals reinforcements. In this case, the storage capacity is assumed to be of 197h of discharge[3]. A LNG capacity of 1bcm/yr would thus cost 140 million €.

4.2.5 Storages

Existing **gas storage** are characterized by their injection/withdrawal capacity and their storage capacity. Storages injections of gas into the storage or withdrawals of gas from their storage to supply the system are optimized. Gas storage level must be equal at the beginning and at the end of each year, which means that it is impossible to empty the storage completely to face an exceptional disruption. Storage also has a reduced installed

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[2] Source: https://www.eia.gov/todayinenergy/detail.cfm?id=10511#, EIA

[3] Source: report on unit investment cost indicators and corresponding reference values for electricity and gas infrastructure, ACER, 2015

capacity for withdrawal (respectively injection) when the storage becomes empty (respectively full), to take into account pressure constraints.

In capacity expansion simulation, **Gas reserves** can be added to the model. These storages, characterized by a withdrawal capacity and a storage capacity (corresponding to 1175 hours of withdrawal) are supposed to start full at the beginning of the year, and can be used only for security of supply purposes. In particular, they can be used for imports disruptions but not under poor weather conditions. These reserves can be installed at any node of the model, at the investment cost of 59 k€/MW[4] meaning that a withdrawal capacity of 1 bcm/year would cost 72.9 million€.

4.3 Power assets modelling

4.3.1 Consumption

Power consumption is represented at an hourly time step for each node in the model. Yearly consumption is an input of the scenario. Profiles used are based on ENTSO-E inputs, and depend on the temperature data. They are also correlated with renewables generation curves.

4.3.2 Thermal generation

In each country, **thermal generation** is represented by an asset per fuel type (including nuclear, coal, lignite, oil and other), and two assets for gas-based generation (OCGT and CCGT). The generation of each of these assets is optimized at each hour, depending on its installed capacity (based on the scenario data) and its availability (based on TSO historic data). Generation costs depend on its efficiency as well as fuel costs, based on the scenario. CO2 emissions costs are also included and depend on the ETS price, based on the scenario, as well as CO2 emission rates of each fuel.

In capacity expansion simulations, CCGT and OCGT can be added or optimized, at the cost of 76.9k€/MW/year and 44.3 k€/MW/year respectively, including investment and maintenance costs.

4.3.3 Renewables generation

In each country, **renewable generation** is represented by an asset per type of generation, including wind onshore, wind offshore, solar PV, hydro run-off-river, biomass and other renewables (including tidal, geothermal energy). The generation of each one of these assets is based on its installed capacity as defined in the scenario, and on its generation profile, based on historical generation data.

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[4] Source: report on unit investment cost indicators and corresponding reference values for electricity and gas infrastructure, ACER, 2015

4.3.4 Hydro storages

Two types of hydro storage are also represented in the model. **Seasonal storage** (big dams), characterized by a high storage capacity and usually use for seasonal trade-offs, are represented by an installed capacity, a storage capacity and a water inflow curve. Its generation is optimized, taking into account that its storage capacity has to stay at each time above a guide curve, representing its typical usage. **Pumped hydro storage** is characterized by a lower storage capacity and usually does daily or weekly trade-offs. It is defined by its installed capacity, specified by the scenario, its storage capacity and its efficiency. At each hour, the pumped hydro storage can either produce or consume electricity, as decided by the optimization.

4.3.5 Interconnections

Electricity can be exchanged from node to node using **interconnections**. Each interconnection is considered bidirectional, and can be used at each time step in one direction, up to its installed capacity (NTC values).

In capacity expansion simulation, power interconnections can be added or reinforced, at the cost of 8.8 k€/MW/100km/year[5].

4.4 More detail on scenarios

4.4.1 Overview

As introduced in section 1, a set of three 2030 scenarios was chosen to assess infrastructure needs in various contexts. A fourth 2050 scenario was chosen to assess the risk of stranded assets as Europe meet his Climate and energy targets. This section focuses on the three 2030 scenarios.

Table 3 : Scenarios data sources

Scenario 2030	Source	Model used	Year
On Track	European Commission – EE30 scenario	PRIMES	2014
Current trends	European Commission – Reference scenario[6]	PRIMES	2013
High demand	ENTSO-E vision 3[7] and ENTSO-G Green[8]		2014 / 2015

[5] Source: ECF power perspective 2030

[6] Source: http://ec.europa.eu/transport/media/publications/doc/trends-to-2050-update-2013.pdf

[7] Source: https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2014/Pages/default.aspx

Figure 1 shows gas and electricity demand for all European countries. Note that for the PRIMES scenarios "On track" and "Current trends", data was only provided on European Union member states. It has been completed by ENTSO-E/G data from scenario V1-Grey which reflects few evolutions the European mix by 2030.

- The "On track" includes higher levels of overall electrification of the economy (mainly in heating and transport sectors) and was computed to assess the revised targets.
- The "Current trends" scenario undershooting the 2030 targets for greenhouse gases (GHG), renewable energy sources (RES) and energy efficiency (EE)
- The "High demand" scenario assumes a high development of RES in the power system, but it does not attain to 2030 energy efficiency and GHG targets. It also shows an increase of the gas consumption as it models a significant coal to gas switch in the power sector in the next 15 years.

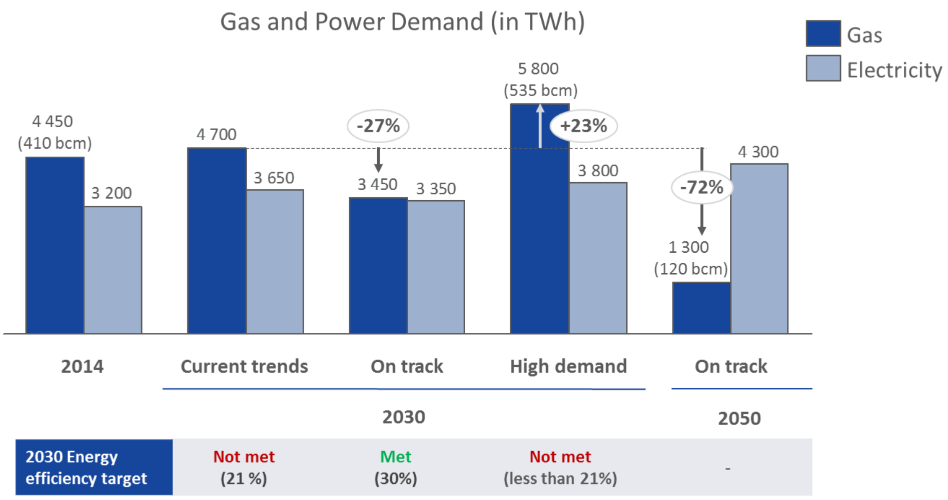

Figure 1 - Gas and electricity demand in Europe

4.4.2 Relevant data

Figure 2 shows the sectoral split for energy consumption by sector. This split is not available for the High demand scenario. It also gives a view on what are the expected evolution to 2050.

[8] Source: http://www.entsog.eu/publications/tyndp#ENTSOG-TEN-YEAR-NETWORK-DEVELOPMENT-PLAN-2015

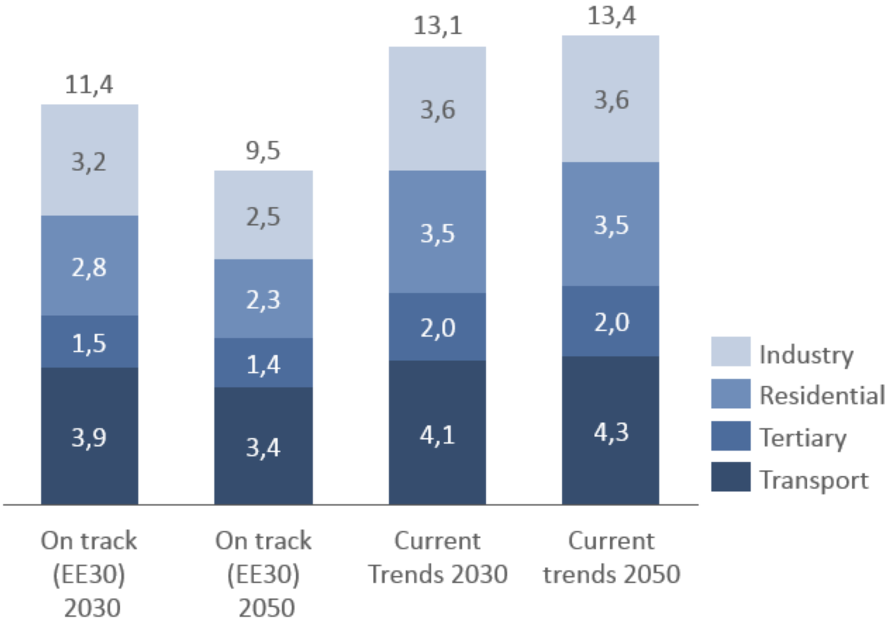

Figure 2: Energy demand – split by sector (in thousands of TWh)

Figure 3 shows the different power generation mixes. One can see that the high demand scenario has the highest renewable share in electricity production (47% vs 37% and 34% for the on track and Current trends scenarios, respectively).

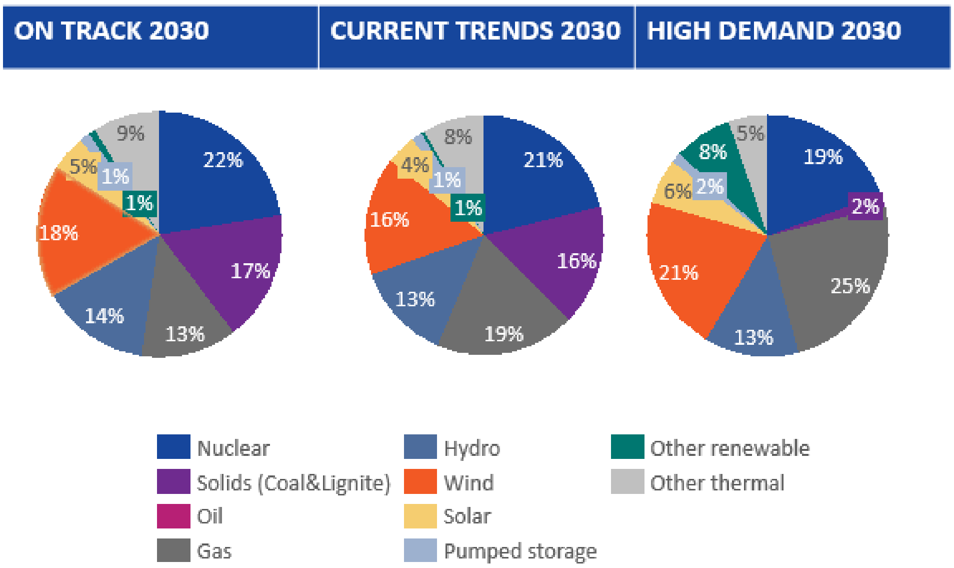

Figure 3: Power generation mix in standard cases

Figure 4 shows the split between imports and domestic production to fulfill gas demand.

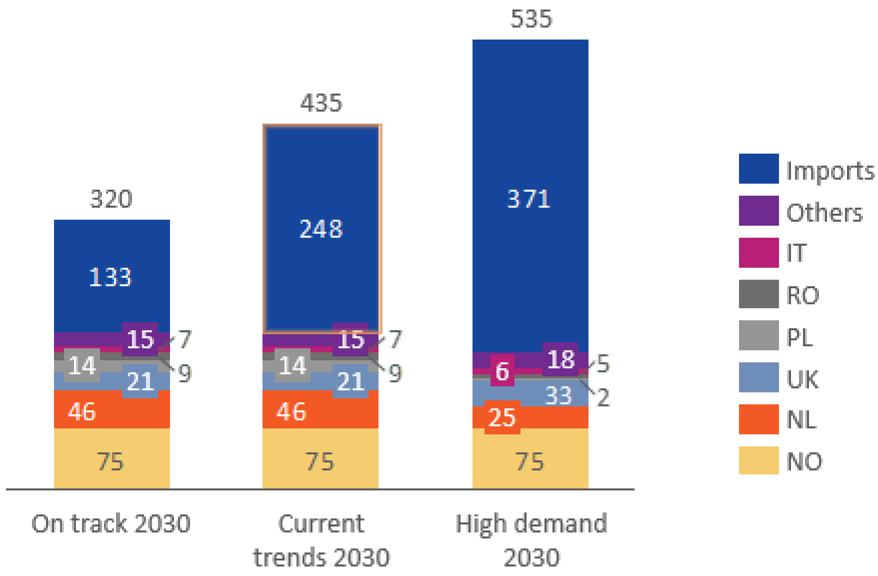

Figure 4: European gas domestic production (bcm)

		ON TRACK	CURRENT TRENDS	HIGH DEMAND
POWER	Total Electricity demand (TWh)	3350	3573	3830
	% RES in power generation	37%	34%	47%
	% RES overall	28%	24%	
GAS	Total gas demand (bcm)	320	435	535
	Of which are imports (%)	132.6 (41%)	247.6 (57%)	370.5 (69%)
	Of which are domestic production (incl Norway)	187 (59%)	187 (43%)	164 (31%)
EU 2030 Targets	EE (27-30%)	31%	21%	Not met
	RES (27%)	28%	24%	50% RES in power generation
	GHG (40%)	40%	32%	Not met