Annex II
Methodology

Scenario Report

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ANNEX II: Methodology

Contents

1. Scenario building methodology

The scenarios presented within the report have all been subject to various processes in order to collect, develop and create input and output datasets. The following section details the methodologies used in order to offer stakeholders insight and transparency into the process.

1.1. Assumptions for fuel and carbon prices

Fuel and carbon prices are key inputs to the development process. The ENTSOs have used the information provided by the IEA World Energy Outlook (WEO), which considers the global context and development that influences commodity prices.

The storyline for each scenario is used to map the World Energy Outlook scenario to the respective ENTSOs counterpart. The majority of the data used reflects that of the World Energy Outlook 2016 report, which has the scenarios of Current Policies, New Policies and the 450 Scenario. In order to reflect the storylines the CO_2 prices were increased for Distributed Generation.

Following the draft scenario report public consultation, the Sustainable Transition 2030 scenario was mapped to World Energy Outlook 2016 New Policy Prices with an adjustment in Carbon Price to set the merit order to Gas before Coal. The change was due to feedback received from stakeholders and to retain consistency in the approach to merit order setting between TYNDP cycles and CBA project assessments. The Low Oil Price Scenario from WEO 2015 retained for Sustainable Transition 2040 since the Identification of System Need report studies have already been carried out with these fuel prices.

Further insight into these changes, plus the effects and usage of prices can be found within the annex supporting this report. The fuel prices for the EUCO 2030 scenario are provided directly by DG ENER.

For power generation, these inputs determine the marginal prices of each thermal power unit depending on its efficiency and emissions. Each unit is linked to one fuel price depending on its type.
Gas price will be used as the reference price for gas supplies during the TYNDP assessment.

The following table provides a summary of the fuel prices used within the scenario building framework. All prices should be considered as expressed in real terms, values shaded with a grey background are based on the WEO 2016 prices in €2015. Nuclear, Lignite and Oil Shale prices are derived through comparison of various sources, please refer to individual sections for further information. A particular case is made for biofuel powered units where the possibility to specify a price for biofuel for each country was possible (defined by each of the TSOs).

		Fuel & CO_2 prices								
	Year	**2020**	**2025**	**2025**	**2030**	**2030**	**2030**	**2040**	**2040**	**2040**
	Scenario	**Expected Progress**	**Coal Before Gas**	**Gas Before Coal**	**Sustainable Transition**	**EUCO**	**Distributed Generation**	**Sustainable Transition**	**Global Climate Action**	**Distributed Generation**
€/net GJ	**Nuclear**	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
	Lignite	1.1	1.1	1.1	1.1	2.3	1.1	1.1	1.1	1.1
	Hard coal	2.3	2.5	2.1	2.7	4.3	2.7	2.5	1.8	2.8
	Gas	6.1	7.4	7.0	8.8	6.9	8.8	5.5	8.4	9.8
	Light oil	15.5	18.7	15.5	21.8	20.5	21.8	17.1	15.3	24.4
	Heavy oil	12.7	15.3	12.7	17.9	14.6	17.9	14.0	12.6	20.0
	Oil shale	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
€/ton	**CO_2 price**	18.0	25.7	54.0	84.3	27.0	50.0	45.0	126.0	80.0
	Main Fuel Price Source (Rows shaded Grey)	*WEO 2016 New Policies*	*WEO2016 New Policies*	*WEO 2016 450*	*WEO 2016 New Policies with Higher Carbon Price*	Fuel Prices Provided by DG Energy	*WEO 2016 New Policies with higher CO_2*	*WEO 2016 New Policies Fuel Prices adjusted to create a "Low Oil Price Scenario"*	*WEO 2016 450*	*WEO 2016 New Policies with higher CO_2*

Table 1: Fuel & CO_2 Price Assumptions

This section is structured in three parts:

- Fuel prices that are considered as constant over the time and scenarios;
- Prices that are changing with the time and scenarios;
- Prices used for TYNDP 2018 storylines and adjustments made to WEO prices or reference from DG Energy for EUCO 2030 scenario.

All prices should be considered as expressed in real terms (in this case as they are based on the WEO prices), in €2015.

1.1.1. Fuel prices that remain constant over all the scenarios

Nuclear price

The nuclear fuel price is assumed constant over the whole time horizon and all scenarios.
This price includes the following components:

- U_3O_8 price
- Conversion price
- Enrichment price
- Fuel fabrication

The final nuclear fuel price is calculated by summing the four components mentioned. A number of expert sources are referenced in the chart below, the final price for nuclear is determined by taking an average of the costs. Therefore the market models are using a price of 0.47 €/GJ for the nuclear fuel.

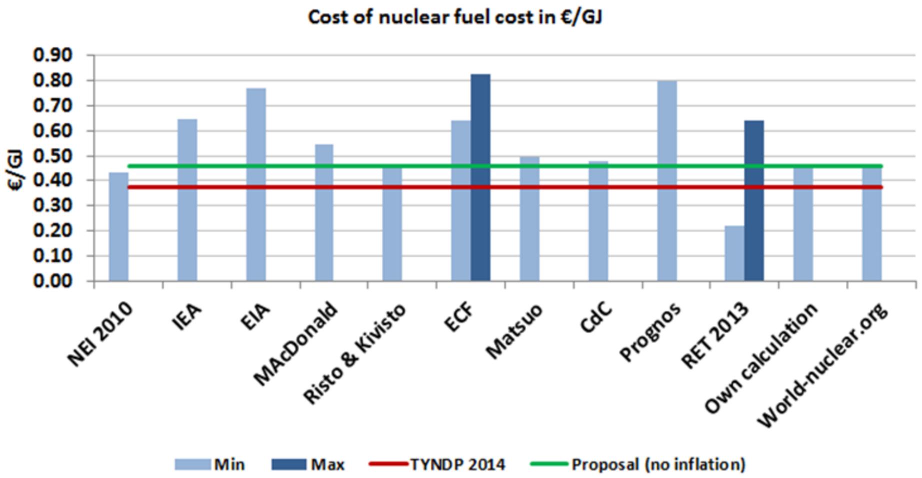


Figure 1: Nuclear price

The nuclear fuel price is set by the world demand and supply and is affected in a very limited way by the drivers identified in the storylines, therefore the nuclear fuel price is assumed to be the same for all the scenarios, including the EUCO scenario.

The proposal for TYNDP 2018 is to use the same price across all scenarios set at 0.47 €/GJ.

Lignite price

The cost of extraction and the calorific value of the lignite drive the prices. The following chart presents lignite prices from various references. For TYNDP 2018 an average lignite price of 1.1 €/GJ is calculated from the data identified. Since lignite is consumed locally (due to its low calorific value), it can be considered as stable for the future.

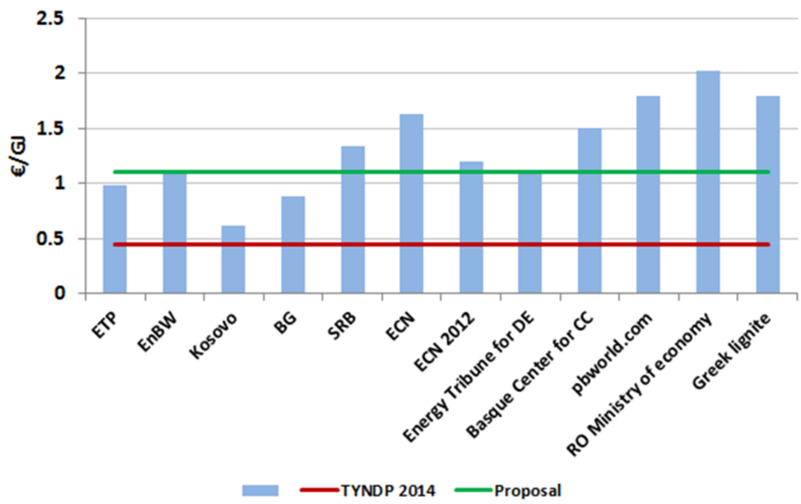


Figure 2: Lignite price

The proposal for TYNDP 2018 is to keep the same price of 1.1 €/GJ for all the countries and time horizons.
Exception:
The lignite price for the EUCO scenario was provided by DG Energy the cost provided was 2.3 €/GJ.

Oil shale price

Oil shale is only present in Estonia at the moment. The oil shale price is set to 2.3 €/GJ and is constant for all scenarios.

The proposal for TYNDP 2018 is to use the same price as for the TYNDP 2016 of 2.3 €/GJ.

1.1.2. Fuel prices that change depending on the scenario

World energy fuel prices for oil, gas and coal are typically hard to predict. The IEA World Energy Outlook provides an annual report on the possible future energy trends and the associated fossil fuel and carbon prices for the 2020 to 2040 time frame.

The World Energy Outlook does not provide the price of commodities in the format for the market study tools. The World Energy Outlook does, however provide conversion tables to calculate the fuel prices in €/GJ.

The following conversion tables are extracted from the WEO2016:

General conversion factors for energy

Convert to:	TJ	Gcal	Mtoe	MBtu	GWh
From:	multiply by:				
TJ	1	238.8	2.388×10^{-5}	947.8	0.2778
Gcal	4.1868×10^{-3}	1	10^{-7}	3.968	1.163×10^{-3}
Mtoe	4.1868×10^{4}	10^{7}	1	3.968×10^{7}	11 630
MBtu	1.0551×10^{-3}	0.252	2.52×10^{-8}	1	2.931×10^{-4}
GWh	3.6	860	8.6×10^{-5}	3 412	1

Note: There is no generally accepted definition of boe; typically the conversion factors used vary from 7.15 to 7.40 boe per toe.

Table 2: WEO 2016 conversion factors for energy

The World Energy Outlook provides fuel prices in USD dollars, so for the purposes of modelling the European power market it is necessary to use the appropriate exchange rate, see following table:

Currency conversions

Exchange rates (2015 annual average)	1 US Dollar equals:
British Pound	0.65
Chinese Yuan	6.23
Euro	0.90
Indian Rupee	65.20
Indonesian Rupiah	13 435.88
Japanese Yen	121.04
Russian Ruble	60.70
South African Rand	12.75

Table 3: WEO 2016 currency conversion

The World Energy Outlook 2016 provides fuel prices for 2015, 2020, 2030 and 2040, see extracts from report for fuel prices and carbon prices. To derive the fuel and carbon prices for 2025 a linear interpolation is necessary.

Table 1.4 ▷ Fossil-fuel import prices by scenario

		New Policies Scenario			Current Policies Scenario			450 Scenario		
Real terms ($2015)	2015	2020	2030	2040	2020	2030	2040	2020	2030	2040
IEA crude oil ($/barrel)	51	79	111	124	82	127	146	73	85	78
Natural gas ($/MBtu)										
United States	2.6	4.1	5.4	6.9	4.3	5.9	7.9	3.9	4.8	5.4
European Union	7.0	7.1	10.3	11.5	7.3	11.1	13.0	6.9	9.4	9.9
China	9.7	9.2	11.6	12.1	9.5	12.5	13.9	8.6	10.4	10.5
Japan	10.3	9.6	11.9	12.4	9.9	13.0	14.4	9.0	10.8	10.9
Steam coal ($/tonne)										
OECD average	64	72	83	87	74	91	100	66	64	57
United States	51	55	58	60	56	61	64	53	52	49
European Union	57	63	74	77	65	80	88	58	57	51
Coastal China	72	78	86	89	79	92	98	73	72	67
Japan	59	66	77	80	68	84	92	61	59	53

Notes: MBtu = million British thermal units. Gas prices are weighted averages expressed on a gross calorific-value basis. All prices are for bulk supplies exclusive of tax. The US price reflects the wholesale price prevailing on the domestic market. The China and European Union gas import prices reflect a balance of LNG and pipeline imports, while the Japan import price is solely LNG.

Table 4: WEO 2016 Fossil fuel import prices

Table 1.1 ▷ CO_2 price assumptions in selected regions by scenario

$2015 per tonne	Region	Sectors	2020	2030	2040
Current Policies Scenario	European Union	Power, industry, aviation	18	30	40
	Korea	Power, industry	18	30	40
New Policies Scenario	European Union	Power, industry, aviation	20	37	50
	Chile	Power	6	12	20
	Korea	Power, industry	20	37	50
	China	Power, industry	10	23	35
	South Africa	Power, industry	7	15	24
450 Scenario	United States, Canada, Japan, Korea, Australia, New Zealand	Power, industry	20	100	140
	European Union	Power, industry, aviation	20	100	140
	China, Russia, Brazil, South Africa	Power, industry	10	75	125

Table 5: WEO 2016 CO_2 price assumptions

The storylines for each ENTSO scenario is used to map the World Energy Outlook scenario with to the respect ENTSO counterpart. The WEO 2016 report, which has three scenarios (Current Policies, New Policies, 450 Scenario) which are described in further detail below. The fuel prices for the EUCO 2030 scenario are provided directly by DG Energy.

	Fuel & CO_2 prices								
Year	**2020**	**2025**	**2025**	**2030**	**2030**	**2030**	**2040**	**2040**	**2040**
Scenario	**Expected Progress**	**Coal Before Gas**	**Gas Before Coal**	**Sustainable Transition**	**EUCO**	**Distributed Generation**	**Sustainable Transition**	**Global Climate Action**	**Distributed Generation**
Key Fuel Price Source (Rows shaded Grey)	*WEO 2016 New Policies*	*WEO2016 New Policies*	*WEO 2016 450*	*WEO 2016 New Policies with Higher Carbon Price*	Fuel Prices Provided by DG Energy	*WEO 2016 New Policies with higher CO_2*	*WEO 2016 New Policies Fuel Prices adjusted to create a "Low Oil Price Scenario"*	*WEO 2016 450*	*WEO 2016 New Policies with higher CO_2*

Table 6: Fuel & CO_2 price assumption scenario alignment

[taken from IEA website]

*- **New Policies Scenario** of the World Energy Outlook broadly serves as the IEA baseline scenario. It takes account of broad policy commitments and plans that have been announced by countries, including national pledges to reduce greenhouse-gas emissions and plans to phase out fossil-energy subsidies, even if the measures to implement these commitments have yet to be identified or announced.*

*- **Current Policies Scenario** assumes no changes in policies from the mid-point of the year of publication (previously called the Reference Scenario).*

*- **450 Scenario** sets out an energy pathway consistent with the goal of limiting the global increase in temperature to 2°C by limiting concentration of greenhouse gases in the atmosphere to around 450 parts per million of CO_2.*

Scenarios that are directly mapped to World Energy Outlook 2016 or DG Energy fuel prices

1) 2020 Expected Progress
2) 2025 Expected Progress Coal before Gas
3) 2025 Expected Progress Gas before Coal
4) 2030 EUCO mapped directly to DG Energy
5) 2040 Global Climate Action

Scenario where WEO2016 scenarios are adapted to fit with the ENTSOs Storylines

1) 2030 Sustainable Transition
   a. Based on WEO 2016 New Policies
   b. Carbon Price adjusted to set merit order Gas before Coal
2) 2040 Sustainable Transition
   a. A "Low Oil Price" Scenario generated from WEO2016 New Policies
   b. Setting the Merit order to Gas Before Coal
3) 2030 & 2040 Distributed Generation
   a. Based on WEO2016 scenario New Policies, carbon price adjusted to create an investment signal that enables developments in distributed generation technologies.

1.1.2.1. Fuel Price setting for 2040 Sustainable Transition

Creating the 2040 Sustainable Transition fuel prices is a two-step process:

Step 1 Creating the "Low Oil Price" Scenario

A "Low Oil Price" scenario, and therefore low gas price, was developed for Sustainable Transition 2040 in order to reflect the storyline. The agreed process uses the methodology employed in the World Energy Outlook 2015 report. The WEO 2015 report uses scaling factors to adjust the New Policiesnew policies scenario for coal, gas and oil prices to create a Low Oil Price scenario.

	Conversion from New Policies to Low oil fuel prices	"Low Oil Price" Scenario 2040
Hard Coal	90%	2.5 € /GJ
Gas	80%	7.8 € /GJ
Light Oil	70%	17.1 € /GJ

Table 7: Conversion factors for Sustainable Transition prices

Step 2 Setting the Merit order to Gas before Coal

The next step for alignment of the fuel prices to the Sustainable Transition 2040 storylines is to set a Gasgas before Coalcoal merit order. The method decreases the gas price in order that New CCGT Gas appears before Hard Coal New in the merit order.

Horizon	Gas Adjustment Ratio to Achieve Gas before Coal	Final Gas Price for Merit order adjustment
Gas Price 2040	70%	5.5 € /GJ

Table 8: Conversion factors for Sustainable Transition merit order

Note: For the scenario re-run of Sustainable Transition 2040, this approach was retained, to ensure consistency with the results presented in the TYNDP18 Identification of System Needs Report

1.1.2.2. Fuel Price setting for 2030 Sustainable Transition

The fuel prices for Sustainable Transition 2030 are based on the World Energy Outlook 2016 New Policies scenario.

The carbon price for the scenario is increased to €84.3/Tonne, to set the merit order to Gas before Coal.

Note: For the scenario re-run of Sustainable Transition 2030, this approach was approved, to ensure consistency with the methodology used in Vision 3 of ENTSOE TYNDP16.

1.1.2.3. Fuel Price setting for 2030 & 2040 Distributed Generation

The fuel prices for Distributed Generation 2030 and 2040 are based on the World Energy Outlook 2016 New Policiespolicies scenario.

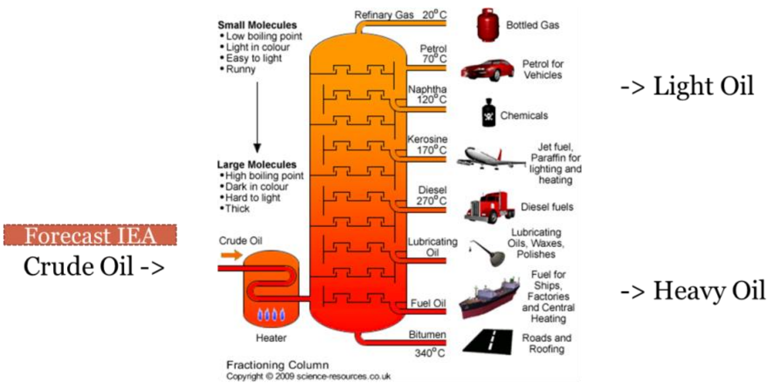
The carbon price for the scenario is increased to €50/Tonne, in order that during the RES-E optimisation and Thermal reduction process the correct investments signals are created to invest in distributed generation technologies

1.1.2.4. Converting World Energy Outlook Fuel Prices to Power Market Fuel Prices

Oil (Light Oil and Heavy Oil)

Light and Heavy oil categories are thermal units used within the ENTSO-E power market tools. The reference Oil price is obtained from the World Energy Outlook scenarios. The €/GJ price for the Light and Heavy oil categories are calculated in accordance with conversion ratios that are linked to the oil fractioning process.

<u>Conversion factors from Crude Oil to light oil and heavy oil:</u>



Source: science-resources.co.uk

Figure 3: Crude oil conversion

<u>Crude Oil -> Light Oil</u>
Historic average. +28% between crude and gasoline (Light Oil).
Source: https://www.eia.gov/dnav/pet/pet_pri_spt_s1_m.htm

<u>Crude Oil -> Heavy Oil</u>
Historic average. +5% between crude and heating oil (Heavy Oil).
Source: https://www.eia.gov/dnav/pet/pet_pri_spt_s1_m.htm

Gas:

Gas prices are taken from the WEO. The MBTu to GJ conversion used is the one specified by the World Energy Outlook table of energy conversion.

Hard Coal:

Hard coal prices are taken from the WEO or DG Energy assumptions.

The coal calorific value of 25 GJ/ton is taken as conversion from the WEO prices. This is the calorific value used in Europe (CIF ARA 6000 NAR).

https://www.platts.com/IM.Platts.Content/methodologyreferences/methodologyspecs/european_power_methodology.pdf
https://s3-eu-west-1.amazonaws.com/cjp-rbi-icis-compliance/wp-content/uploads/2013/08/Carbon-Emissions.pdf

1.1.2.5. CO_2 price

		CO_2 prices								
	Year	**2020**	**2025**	**2025**	**2030**	**2030**	**2030**	**2040**	**2040**	**2040**
	Scenario	**Expected Progress**	**Coal Before Gas**	**Gas Before Coal**	**Sustainable Transition**	**EUCO**	**Distributed Generation**	**Sustainable Transition**	**Global Climate Action**	**Distributed Generation**
€/ton	**CO_2 price**	18.0	25.7	54.0	84.3	27.0	50.0	45.0	126.0	80.0
	Fuel Price Source	*WEO 2016 New Policies*	*WEO2016 New Policies*	*WEO 2016 450*	*WEO 2016 New Policies with Higher Carbon Price*	Fuel Prices Provided by DG Energy	*WEO 2016 New Policies with higher CO_2*	*WEO 2016 New Policies Fuel Prices adjusted to create a "Low Oil Price Scenario"*	*WEO 2016 450*	*WEO 2016 New Policies with higher CO_2*

Table 9: CO_2 prices by scenario

For most of the scenarios, CO_2 prices are mapped to the World Energy Outlook 2016 or DG Energy Carbon prices:

1) 2020 Expected Progress
2) 2025 Expected Progress Coal before Gas
3) 2025 Expected Progress Gas before Coal
4) 2030 EUCO mapped directly to DG Energy
5) 2040 Sustainable Transition
6) 2040 Global Climate Action

Scenario where WEO2016 scenarios were adapted to fit with the ENTSOs Storyline

1) 2030 Sustainable Transition (to set the merit order between gas and coal), 2030 & 2040 Distributed Generation (price to create an investment signal in distributed generation technologies)

Biofuel:

Biofuel is either imported or taken from a local market. Subsidies in several countries exist leading to price differences between biomass/biofuel in Europe. As done in TYNDP 2016, the possibility of LAC to provide Biofuel data was made. The result in this collection is the following:

<table>
<tr><th rowspan="2">Fuel type</th><th>2020</th><th>2025</th><th>2025</th><th>2030</th><th>2030</th><th>2030</th><th>2040</th><th>2040</th><th>2040</th></tr>
<tr><th>Expected Progress</th><th>Coal Before Gas</th><th>Gas Before Coal</th><th>Sustainable Transition</th><th>Distributed Generation</th><th>EUCO*</th><th>Sustainable Transition</th><th>Distributed Generation</th><th>Global Climate Action</th></tr>
<tr><td>Bio Hard coal</td><td colspan="3">3.9</td><td colspan="2">10.8</td><td>8.9</td><td colspan="3">5.5</td></tr>
<tr><td>Bio Hard coal (DK)</td><td colspan="3">8.88</td><td colspan="2">9.36</td><td>n/a</td><td colspan="3">9.8</td></tr>
<tr><td>Bio Hard coal (FI)</td><td colspan="3">6.1</td><td colspan="2">8</td><td>n/a</td><td colspan="3">9.9</td></tr>
<tr><td>Bio Oil shale</td><td colspan="3">5.7</td><td colspan="2">6</td><td>6</td><td colspan="3">6</td></tr>
<tr><td>Bio Oil shale (EE)</td><td>4.5</td><td>5.5</td><td>5.5</td><td colspan="2">6</td><td>6</td><td colspan="3">6</td></tr>
<tr><td>Bio Heavy oil</td><td colspan="3">8.33</td><td colspan="2">8.95</td><td>8.9</td><td colspan="3">8.95</td></tr>
<tr><td>Bio Heavy oil (DK)</td><td colspan="3">6.84</td><td colspan="2">7.38</td><td>n/a</td><td colspan="3">8.01</td></tr>
<tr><td>Bio Lignite</td><td colspan="3"></td><td colspan="2"></td><td>6</td><td colspan="3"></td></tr>
<tr><td>Bio Lignite (PL)</td><td colspan="3">3.9</td><td colspan="2">5.5</td><td>n/a</td><td colspan="3">5.5</td></tr>
<tr><td>Bio Lignite (SK)</td><td colspan="3">1.55</td><td colspan="2">1.55</td><td>n/a</td><td colspan="3">1.55</td></tr>
<tr><td>Bio Lignite (IE)</td><td>2.82</td><td>2.94</td><td>2.39</td><td>2.91</td><td>3.06</td><td>n/a</td><td>3.06</td><td>3.24</td><td>2.31</td></tr>
<tr><td>Bio Gas</td><td colspan="3"></td><td colspan="2"></td><td>6.9</td><td colspan="3"></td></tr>
<tr><td>Bio Gas (SK)</td><td colspan="3">6</td><td colspan="2">6</td><td>n/a</td><td colspan="3">6</td></tr>
</table>

Table 10: Biofuel prices

For DK, FI, IE, PL and SK, the prices mentioned in the table above will be used for biofuel units (if specified in the "Thermal" sheet of the PEMMDB file). The unit's characteristics are the same as the ones of the unit type where the biofuel is specified.

* For EUCO30 region specific differences in Bio-Fuel prices were not applied. (*n/a: not applicable*)

1.1.3. Scenario Merit Order Charts

The following charts provide an indication of the merit order and associated marginal costs for coal, lignite, and gas power plants for each scenario.

1.1.3.1. 2020 & 2025 scenario Merit Orders:

<u>2020: "New Policies" scenario from IEA – Coal before Gasgas scenario</u>

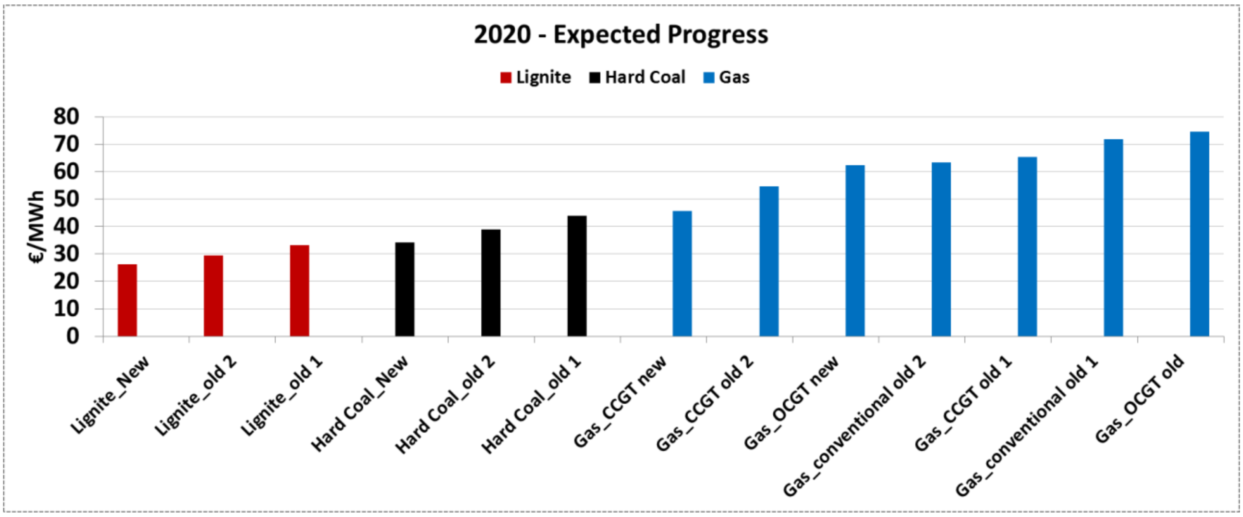


Figure 4: 2020 merit order

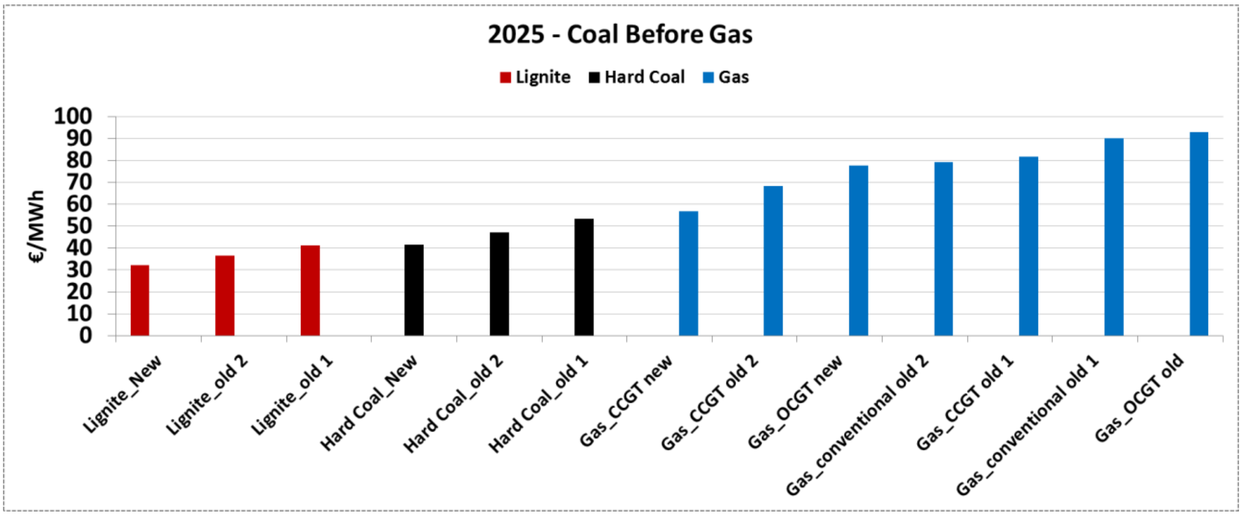


Figure 5: 2025 Coal before Gasgas merit order

<u>2025: "New Policies Scenario" – Gas before Coal (alternative)</u>

Based on the WEO2016 450 Scenario – New CCGT "Gas before Coal" scenario.

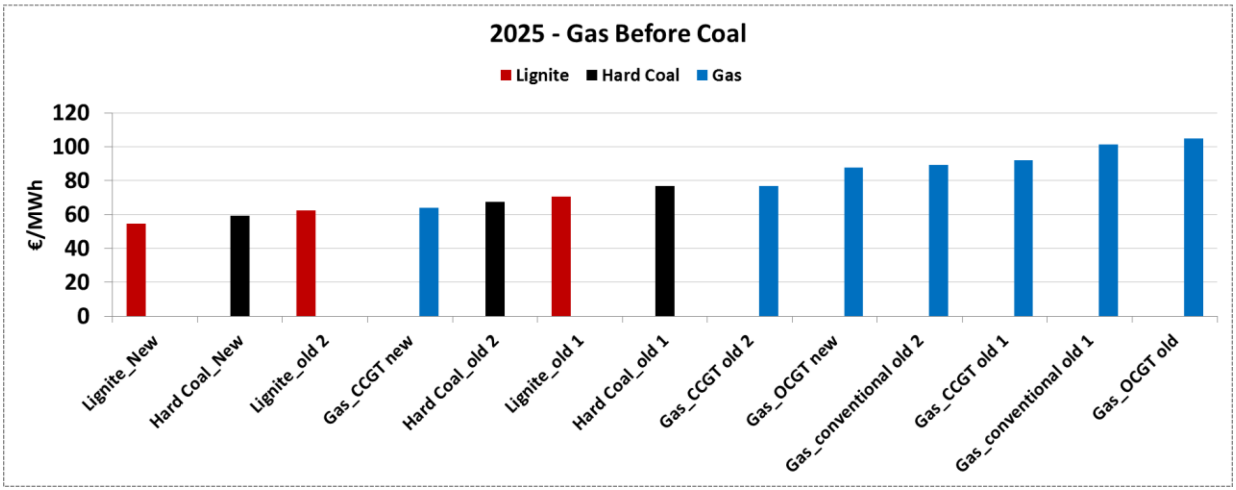


Figure 6: 2025 Gas before Coal merit order

1.1.4. 2030 & 2040 Storylines Merit Orders:

The following charts present the merit order and marginal cost for the coal, lignite and gas power plants in each scenario and time horizon.

1.1.4.1. EUCO 2030

The merit order for the EUCO 2030 scenario is set from the fuel and carbon prices provided by DG Energy used to construct the EUCO 2030 impact assessment report.

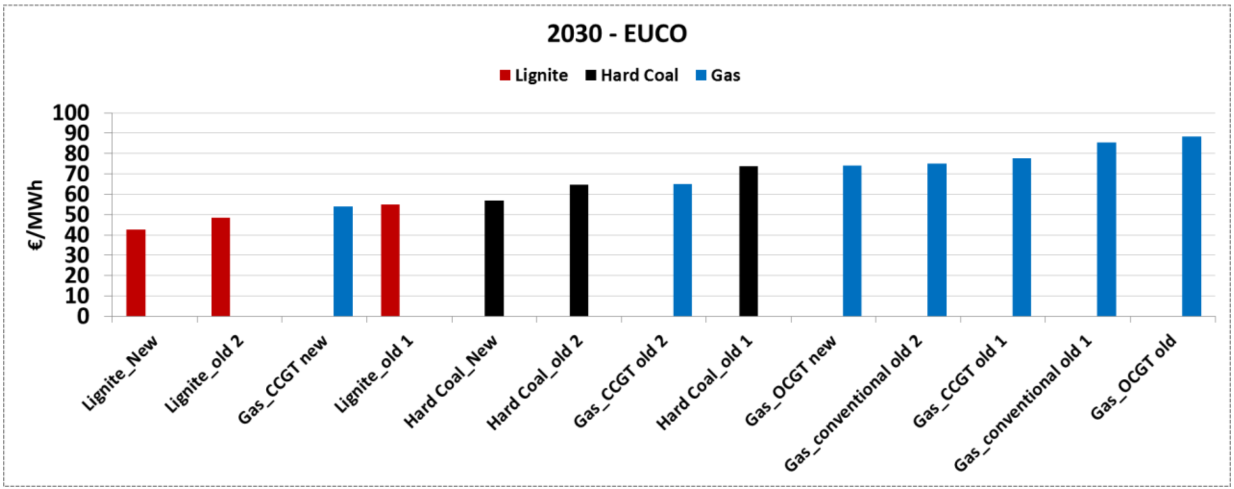


Figure 7: EUCO 2030 merit order

1.1.4.2. Sustainable Transition 2030 & 2040 – Based on a "Low oil" scenario constructed with a low gas price

<u>2030: "Sustainable Transition" – New CCGT Gas Before New Coal</u>

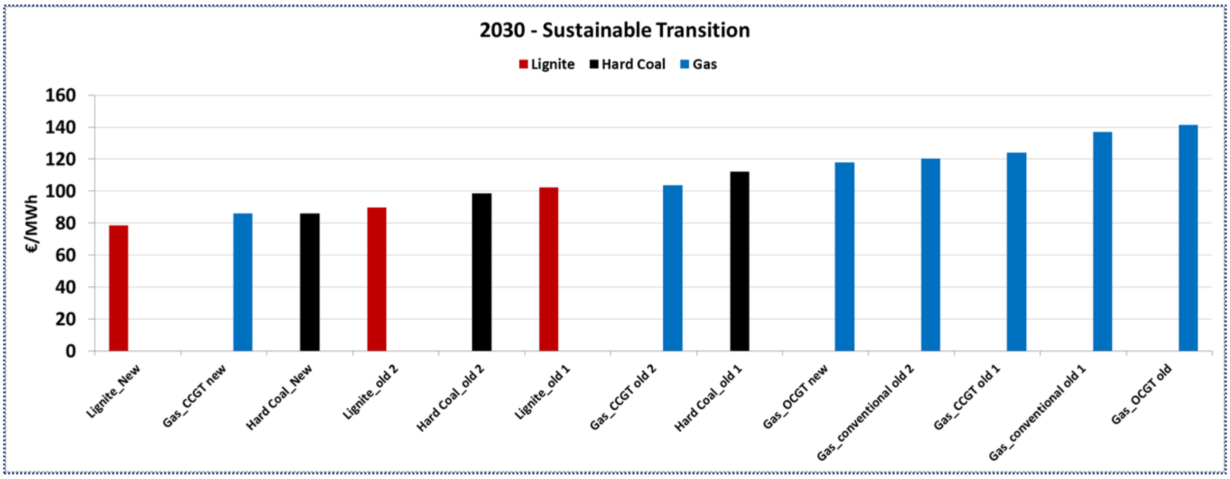


Figure 8: Sustainable Transition 2030 merit order

<u>2040: "Sustainable Transition" – New CCGT Gas Before Coal</u>

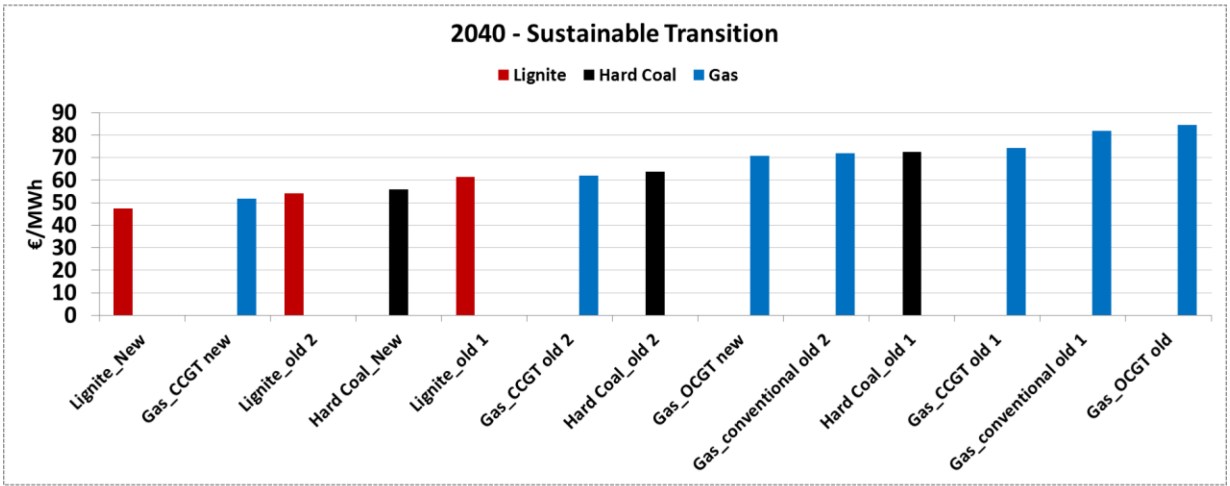


Figure 9: Sustainable Transition 2040 merit order

1.1.4.3. Distributed Generation 2030 & 2040 – Merit Order Charts

A higher CO_2 price is set in order to match the storyline with the investments for a decentralised generation scenario:

- A big reduction in CAPEX for 'small scale technologies'
- A medium level of support/carbon price that helps developing the technologies.

<u>2030: "Distributed Generation"</u>

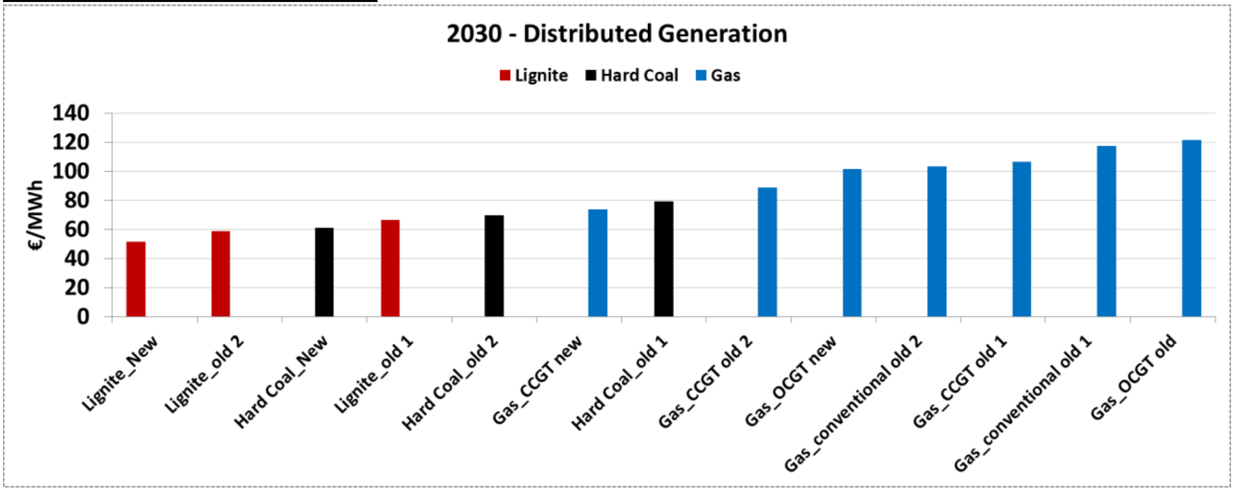


Figure 10: Distributed Generation 2030 merit order

<u>2040: "Distributed Generation"</u>

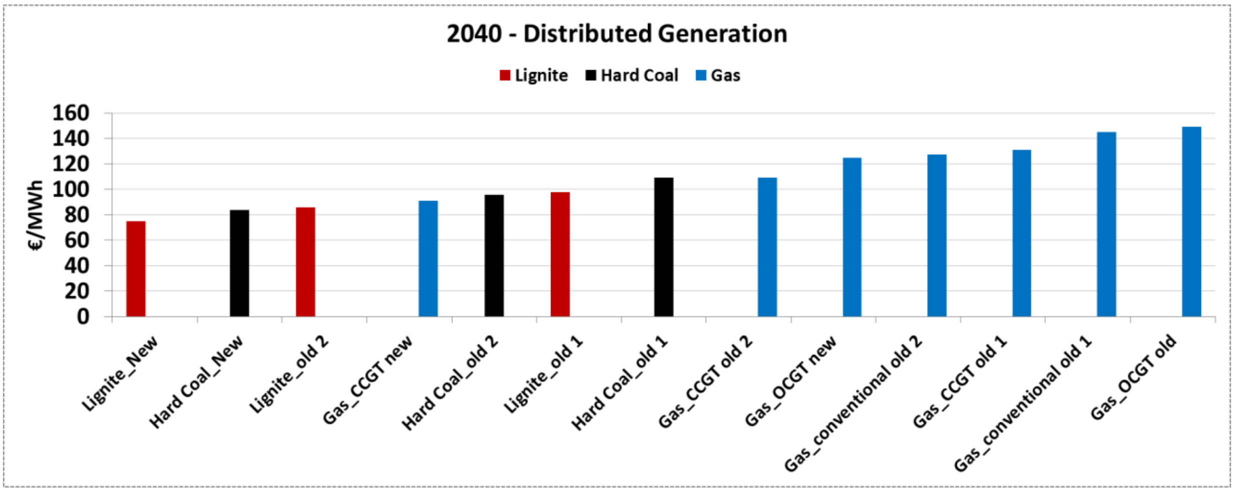


Figure 11: Distributed Generation 2040 merit order

2040 Global Climate Action – "450" scenario

Fuel and carbon prices from the "450" scenario from the WEO are taken. No changes are applied to fuel or carbon prices.

2040: "Global Climate Action"

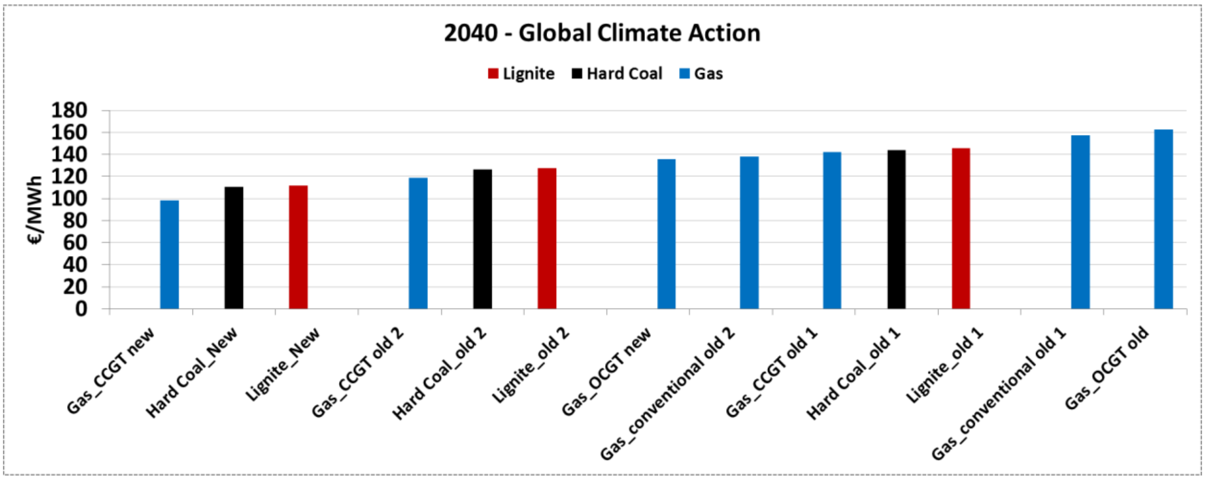


Figure 12: Global Climate Action 2040 merit order

1.2. EUCO30 External Scenario

The ENTSOs have taken input data from the EUCO30 scenario for use within the scenario building process. These inputs were then used to create the granularity of output data necessary in order to develop comparisons between all scenarios.

Wherever possible, data has been directly ported for use, however a key example of where output data will not match the original EUCO30 scenario is in terms of the power generation mix which is determined by the market models used for scenario development by the ENTSO-E.

Further details to the stages of processing this input data is detailed in the following sections.

1.2.1. EUCO30 Electricity installed capacity and generation

For the EUCO30 scenario the source data was provided by the European Commission based on the EUCO30 EC policy scenario. Although the source data contained the basic information needed for modelling the power system, the granularity, the resolution and the definitions of the input data for ENTSO-E tools differed from the source data and thus a methodology to transform the data is necessary which is described in the following section.

Demand data

The source data contained final annual energy demand including electric vehicles and heat pumps. ENTSO-E applies hourly load time series for its electricity system modelling and for the TYNDP 2018, the load time series for different climatic conditions based on three different years (1982, 1984 and 2007) as reference were used as input.

The ENTSO-E market models require multiple climatic demand profiles, in order to build the the country by country annual demand time series there are a number of steps:

1. Native country demand profiles based on a historical normalised hourly profiles for 2015
2. The number of EV and Heat pumps was provided in the EUCO30 data. The annual demand for electric vehicles and the number of heat pumps was estimated using demand profiles applied by ENTSO-E.
3. Next, the hourly demand time series for 34 climate years were generated using an ENTSO-E load profile tool. Part of this process takes into account the temperature sensitivity of the load.
4. As a last step the load time series was calibrated, so that the average annual electricity demand corresponded of 34 climatic years (1982 to 2015) corresponded to the the electricity demand of the EUCO30 data.

Generation capacities:

1. Renewable Generation Sources:
    - The installed generation capacity of RES, especially wind and solar was directly extracted by the source data.
    - For biomass units, there were two categories
        i. Units were modelled as flexible if the must-run share was below 50%.
        ii. If the must-run share was above 50% the units have been considered with an infeed times series corresponding to the must-run capacity.
2. Conventional Power Plants

- The categories for conventional thermal units of the source data have been mapped to categories for thermal power plants applied by ENTSO-E. The splitting of the total generation capacity into blocks has been made using typical block sizes. For must run obligations it was assumed that there are no seasonal patterns.

3. Hydro Generation Plants
    - For Hydro generation patterns the climatic conditions (especially inflow) play an important role. In order to be compatible with the ENTSO-E methodology with regard to consideration of different climatic reference years, the hydro data of the source data was compared to the datasets available for the other ENTSO-E scenarios and it was concluded that the hydro generation data of Sustainable Transition 2030 was closest to the source data of EUCO.

4. Data Mapping Non-EU28 Countries
    - For countries with no source data for the EUCO scenario that are part of the EU28+ scope of the electricity TYNDP2018, the data collected for Sustainable Transition 2030 is used.

1.2.2. EUCO30 Gas demand

The gas demand for power generation data is an output of the ENTSO-E modelling results that were generated applying the methodology detailed in section 1. As with the other scenario modelling output, this electricity net generation has a calculation applied in order to obtain the gas required as fuel input, further details of this can be found in section 1.4.4.

Final demand is determined on a country. level basis from the data provided by the EUCO30 modelling output. This is achieved by removing the demand classified as Power & CHP from the Gross Inland Consumption. Representation of sectoral data has been included for the final scenario report despite the potential differences in the categorisation between those displayed in the EUCO technical report appendix and that of the TYNDP data collection process. Transport is directly reflected, Residential & Commercial and Industrial is split based on percentages determined by TSO input, using data collected for Global Climate Action 2030. Ktoe consumption data has been converted to Gross Calorific Value TWh or GWh in order to provide a direct comparison between datasets.

For countries not represented within the EUCO scenario that are part of the EU28+ scope of the gas TYNDP 2018, data collected for Global Climate Action 2030 will be used as substitute.

1.2.3. EUCO30 Gas supply

As with other scenarios, all potential gas supplies from outside EU are treated independent to the storylines. Supply potentials provide ranges to the assessment model where the supply mixes are assessed during the TYNDP simulations stage to then obtain the final supply mixes results. The same applies to the EUCO30 assessment. Please refer to Annex I: Section 1.2.3 and Annex II: Section 1.4.1 for the details on the supply potentials to be used by ENTSOG for TYNDP 2018 assessment.

1.3. ENTSO-E Processes

The following describes how the input data for TYNDP18 scenarios power market models are derived from the storylines. The storylines have previously been published following stakeholder engagement. The market models are used in the TYNDP to calculate optimal power plant dispatch. From this power market flows, electricity prices, emissions from electricity production and fuel usage from electricity production can be derived. The scenarios are not only used for TYNDP but also for the electricity Mid-term Adequacy Forecast (MAF). The MAF 2017 assesses electricity adequacy at Pan European level at the horizons 2020 and 2025.

Electricity scenarios for the TYNDP 2018 consist of two kinds of scenarios: TOP DOWN scenarios and BOTTOM UP scenarios. BOTTOM UP scenarios are scenarios that are derived with numbers provided from each TSO. TOP DOWN scenarios are derived from the BOTTOM UP scenarios using a combination of rules and different kinds of optimisation.[1] Rules define direct changes to the scenario. E.g.: % change in installed RES capacity, new fuel prices, demand, etc.

1.3.1. Scenario Building Phases

The Scenario process consists of a number of phases:

1) The Definition of Storylines.
    a. Consultation on the Joint ENTSO scenario storylines
2) The construction of the Scenarios. (See Section 1.3.4).
    a. Definition of TYNDP 16 Reference grid (See Section 1.3.3).
3) The use of the Scenarios within modelling frameworks:
    a. MAF
        i. 2020 and 2025 Adequacy Studies
    b. TYNDP
        i. Long Term 2040 System Planning Studies; Identification of System Need
        ii. Determination of TYNDP CBA reference grid
4) Consultation on draft quantified scenarios for ENTSO TYNDP processes (See Section 1.3.2).
    a. Opportunity for Scenario Refinement through TSO & wider stakeholder feedback process
5) The scenario re-run
    a. 2025 & 2030 Scenarios.
    b. Update of Reference grid based on TYNDP18 data collection (See Section 1.3.3).
        i. Scenario outcomes updated in the final scenario report.
        ii. Scenarios passed into the TYNDP18 CBA project Assessments.
    c. 2040 Scenarios
        i. Update of Reference grid based on TYNDP18 Identification of System Need Studies (IoSN) (See Section 1.3.2).
        ii. 2040 Scenario Outcomes updated in final scenario report.

[1] See section 1.2 of the Scenario Report: "Improvements for TYNDP18"

1.3.2. Scenario Re-run Window: Consultation on draft quantified scenarios

The Scenario re-run window provides TSOs with an opportunity to refine the scenarios for the CBA assessment phase in the TYNDP cycle. The following issues could be handled during this re-run process:

d. Additional market nodes are included in the 2025 and 2030 scenarios. The additional market information is important to improve the quality of some CBA project assessments. New nodes include:
    i. Crete (GRO3)
    ii. Corcisa (FR15)
    iii. Iceland (IS00 [Generation data included])
    iv. Israel (IL00)
    v. Tunisia (TN00)
e. Minor corrections on technical information in the generation portfolio, such as must-run requirements, installed capacities, number of units reports, hydro storages etc.
f. Corrections to demand profiles
    i. Updates for new block demand, such as data centres
    ii. Updates for number of electric vehicles or heat pumps
g. Opportunity for market areas to provide feedback on the RES distribution phase
    i. Upper boundaries were included for market areas that had not provided information during the data collections
h. New TYNDP18 Reference Grid available for electricity market simulations
i. New TYNDP18 IoSN grids available for electricity market simulations

The process involved direct feedback from the TSOs long term adequacy correspondents. Each request was dealt with individually, where a correction was requested this was in general approved. If a request was made to change outcomes from the RES distribution or the thermal optimisation phases a consistency check with the storyline was assessed and a response for acceptance or rejection was issued.

1.3.3. Definition of the Reference grid

To construct the ENTSO scenarios a reference network grid is required to enable electricity market simulations to be performed to distribute renewable generation sources and thermal plants where there is a market opportunity for investment. There are number of reference grids involved in the ENTSO scenario building process:

1) The TYNDP 2016 reference grid. Used as a starting point for TYNDP18 scenario building
    - The scenarios are built using a reference grid adapted to its year (all scenarios within one year use the same grid). For the initial release of scenarios, ENTSO-E used the TYNDP 2016 reference grid, which is the most recent data available. This reference grid includes the current network plus all TYNDP 2016 projects which have a commissioning date earlier to the year considered, and which are included in National Development Plans.

2) The TYNDP 2018 reference grid. Used in the final scenario report to show the impact of the project data collection for TYNDP18

- ENTSO-E completed a data collection for TYNDP 2018 interconnection projects to be included in the reference grid at the end of 2017. In its effort to constantly improve the TYNDP and scenarios methodologies, ENTSO-E has decided to modify the selection criteria by making them more restrictive. The next TYNDP reference grid will only include interconnection projects able to prove that they have already started the permitting phase, which indicates that significant investments have already succeeded in planning and designing the project.
- For the production of the final scenario report, ENTSO-E has rerun the scenario models with the new TYNDP 2018 reference grid.

3) The TYNDP 2018 IoSN reference grids. There are three IoSN grids, one for each of the 2040 scenarios. These grids are used to show how the developed scenarios influence the outcomes from the Identification of System Needs studies
    - For the production of the final scenario report, ENTSO-E has rerun the 2040 scenario models with their respective IoSN 2040 reference grid.

1.3.4. How the joint ENTSO scenarios are quantified

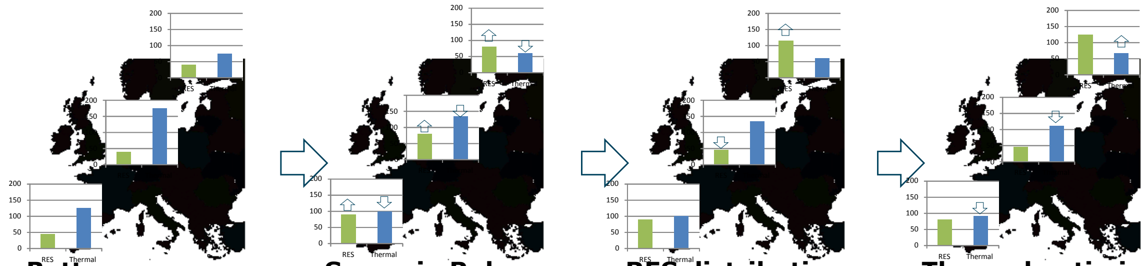
This section details the HOW in the joint ENTSO scenario building process. The following sub-sections provide detailed explanations on the steps and methodologies involved in quanitfiying the scenarios:

- 1.3.5 Step-by-step scenario building
- 1.3.5.1 Annual average electricity demand
- 1.3.6 Forecast of 2030's and 2040's electricity consumption
- 1.3.6.1 Heat pump diffusion
- 1.3.7 Electric vehicles

Figure 13 illustrates the high level steps involved in the development of the "Top-down" scenarios. The ENTSO "Top-Down" Scenarios rely heavily on the Bottom up TSO data. The steps involved are as follows:

- **Bottom up**: this step refers to the process of data collection from TSO Long-term Adequacy Correspondents (LACs). This data captures the national trends such as renewable development, underlying GDP etc. and impact of national developments plans.
- **Scenario Rules:** this step involves application of rules specific to each storyline, for example, removal of thermal units due to decommissioning by a certain time horizon, applying fuel prices, setting RES Targets for the scenario.
- **RES distribution:** this process uses mathematical optimization to distribute surplus Renewable Energy Sources (RES) based on simulated power market price signals.
- **Thermal Optimizaton:** the process is used to assess whether there is thermal units that are no longer economic following the RES distribution process.

(*Further information on scenario building process is found in Section 1.3.5.1*):



Bottom up
Demand 500
RES 125 TWh
CO_2 30 €/ton
Fuel 5 €/GJ

Scenario Rules
Demand 520 TWh
RES 250 TWh
CO_2 90 €/ton
Fuel 3 €/GJ

Remove old thermal

RES distribution
Demand 520 TWh
RES 250 TWh
CO_2 90 €/ton
Fuel 3 €/Gj

Changes location of new wind and PV in order to optimise value of these.

Thermal optimisation
Demand 520 TWh
RES 250 TWh
CO_2 90 €/ton
Fuel 3 €/Gj

Remove thermal with poor economy
Add thermal units with good economy
Add peak capacity

Figure 13 Illustration of scenario building steps from Bottom Up to Top Down scenario.

Year	Name	Type	Derived from
2020	2020 Best Estimate Scenario	Bottom Up	Data collection among TSOs
2025	2025 Best Estimate Scenario Coal Before Gas	Bottom Up	Data collection among TSOs
2025	2025 Best Estimate Scenario Gas Before Coal	Bottom Up	Data collection among TSOs
2030	2030 Sustainable Transition	Bottom Up	Data collection among TSOs
2030	2030 Distributed Generation	Top Down	2030 Sustainable Transition
2030	2030 European Commission EUCO	Top Down	European Commission EUCO30
2040	2040 Sustainable Transition	Top Down	2030 Sustainable Transition
2040	2040 Distributed Generation	Top Down	2030 Distributed Generation
2040	2040 Global Climate Action	Top Down	2030 Sustainable Transition

Table 11: ENTSO-E scenario types

1.3.5. Step-by-step scenario building

The scenario-building process is a process that involves market models (such as BID, Plexos, Powersym, Antares, ETC) and calculation algorithms developed by ENTSO-E.

In the example below the methodology is described step by step from 2030 Sustainable Transition as the starting scenario.

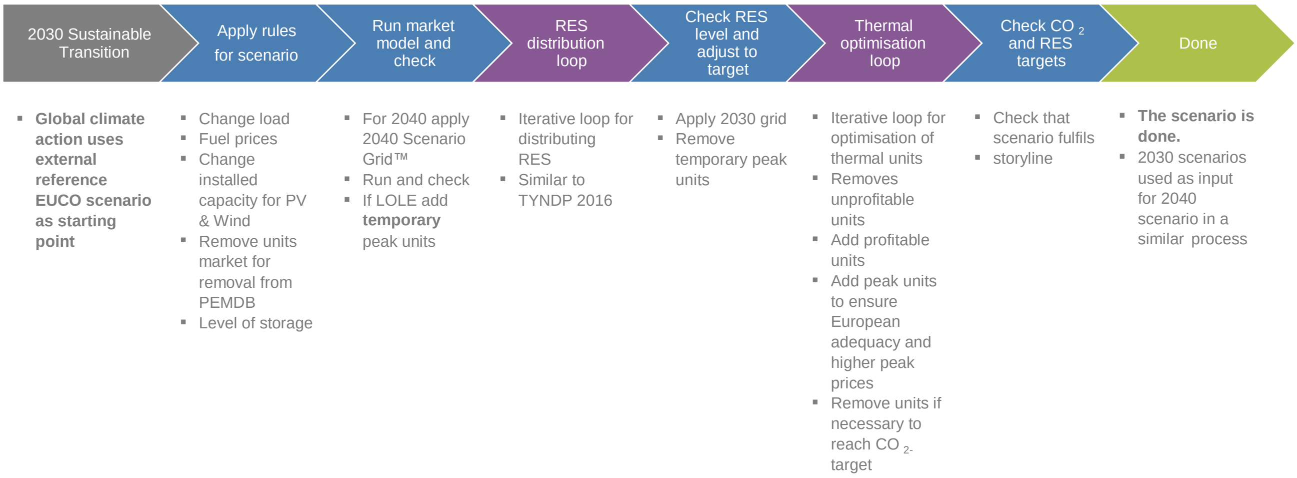


Figure 14: Scenario-building flow for deriving Top Down scenarios.

Step 1: Apply rules for scenario

ENTSO-E modelling team considers each scenario storylines and proceeds with the first data processing. They deliver for each country and according to rules defined in the storylines (based on data provided by TSOs and on targets depending on the type of scenario):

- the yearly load
- the number of electric vehicles and heat pumps
- hourly load profiles corresponding to the determined level of heat pumps and electric vehicles[2]
- installed capacity for wind and solar
- updated list of power plants
- the level of power storage per country.

Step 2: Run market model and check

Thanks to the expertise of its Members' TSOs, ENTSO-E is uniquely able to use the computational power of up to six different commercially available market modelling tools. Modelling future systems with a high level of uncertainty is indeed a precise but inexact science. The specific strength of each of the tools gives considerable room to ENTSO-E experts to consolidate the results of the scenarios.

In this step, the market modelling tools are run and results are checked for errors as well as for Energy not Served (ENS: when the generation and grid are unable to meet the demand in a zone). Peaking units are added to the nodes with too little production to prevent these situations from happening. This is a temporary step in the scenario-building process to ensure that there is no ENS during the RES-optimisation phase. The peaking units are removed before thermal optimisation.

[2] This process uses a tool developed by a separate ENTSO-E taskforce: TF Senora

Step 3: RES distribution

The purpose of the RES-distribution phase is to distribute the photovoltaic, onshore and offshore wind generation between the different zones through a market-based solution. The iterative process ensures that an efficient utilisation of renewable energy is achieved at an EU level rather than a national level. The pricing information from market models linked to external optimisation algorithms enables renewable capacities to be spread efficiently between market zones. RES optimisation also uses boundary conditions for lower and upper RES penetration per market zone.
During RES distribution a stronger grid is used in order to drive a higher share of RES in areas with good conditions for RES.

Step 4: Thermal optimisation

Thermal optimisation is another iterative process involving the market model and external market analysis algorithms. The outputs from the market models are passed through a CAPEX and fixed cost profitability algorithm, which provides indication on what power plants are not economically viable. A second phase in the process evaluates whether new power plants, according to the scenario investment costs, are viable. Temporary peaking units are included at the beginning of the process to ensure adequacy. The methodology does not consider retrofitting or fuel switch of existing power plants.

Step 5: Check and finish optimisation

Run model and check for errors and check that the overall RES-target and climate targets for the scenario is reached. After this the scenario is done and the scenario data is output to the required database format.

Step 6: Scenario Re-Run

The Scenario re-run is a quality check on the scenarios, it provides the TSOs with an opportunity to review the scenario outcomes and provide feedback. The re-run of the scenarios is used to update the scenario reference grids, after the ENTSOE project collection window closes, and the Identification of System Needs study is completed. Once the scenario re-run is ended the final scenarios are passed into the ENTSO's TYNDP CBA project assessment phases.

1.3.5.1. Annual average electricity demand

The following tables represent the demand datasets.
In general the load in the top-down scenarios is constructed using a re-scaling of the national bottom-up load curves of the Sustainable Transition 2030 scenario driven by:

- energy efficiency measures
- introduction of electric vehicles
- introduction of (hybrid) heat pumps
- development of (battery) storages and demand side response

Other assumptions such as demographic and economic growth are also taken into account.

	2020BE	2025BE	2030ST	2030DG	2030EU	2040ST	2040DG	2040GCA
AL	7502	8451	9469	10297	9316	11694	12072	11679
AT	73137	74618	76552	80701	77174	79959	91338	80503
BA	13380	14330	15448	16896	15614	18184	19933	18212
BE	86553	87661	88777	88713	95903	90176	92271	91520
BG	40623	41663	42427	45772	33882	43980	53996	43871
CH	62054	60178	58278	58067	72153	56228	62977	57935
CY	5118	6212	7619	7972	4930	9015	9104	9503
CZ	68676	69254	70858	75868	71471	73992	86574	76433
DE	564663	546924	547275	557532	576235	552456	589809	575865
DKe	15121	16090	16863	18193	15330	18361	21783	20577
DKw	0	29226	30097	32016	23968	31720	36102	33200
DKkf	26245	0	0	0	0	0	0	0
EE	9005	9536	10125	10714	9308	11394	12093	11406
ES	268347	279980	281764	292882	272687	282705	317327	290330
FI	90035	92429	94293	94544	90478	96300	98756	102274
FR	481459	470779	463966	471883	497975	447145	493505	468618
FR15	0	2633	2775	2775	2775	0	0	0
GB	327914	321835	321501	334062	372706	312784	370918	340888
GR	56686	57662	59397	64279	50921	70119	82482	69645
GR03	0	3472	3735	3735	3735	0	0	0
HR	19070	21101	22121	24186	18125	24201	28612	24779
HU	42867	45135	47420	51278	42301	51823	60588	52074
IE	31134	33599	36177	38084	29961	38250	40336	40699
IL00	0	95225	115366	115366	115366	0	0	0
IS00	18307	18330	18330	20291	18330	0	0	0
ITcn	34495	36652	38380	40040	33606	42368	45197	42985
ITcs	48799	51856	54660	57110	48024	61050	65247	61741
ITn	186256	197471	206551	215337	180017	227588	241787	230851
ITs	28950	30677	32089	33370	28585	35254	37351	35684
ITsar	8624	9109	9571	9945	8621	10592	11070	10671
ITsic	18993	20118	21057	21928	19140	23184	24716	23495
LT	11625	12469	13246	14511	11496	14799	17437	15472
LUb	256	264	264	264	264	264	264	258
LUf	1248	1248	1248	1248	1248	1248	1248	1256
LUg	5935	8346	9541	9555	6630	9880	10079	6747
LV	7541	7961	8415	9271	8867	9365	11268	9956
ME	4228	4773	5394	5678	5196	6630	6315	6626
MK	9397	10567	11822	12882	11134	14376	15355	14839
MT	2617	2777	2947	3175	2634	3287	3684	3287
NI	9290	9452	9997	10619	11770	10407	12188	10663
NL	115048	116215	118534	129791	118482	122451	147848	136607
NOm	26896	26735	28063	28171	27417	28259	28601	28260
NOn	19956	21806	23156	23220	22681	24060	23480	24061

NOs	89501	94723	98707	99271	102161	91100	101549	95771
PL	163363	184681	206679	219303	185088	252851	234788	251304
PT	50559	51850	53145	58984	49225	55670	69883	57990
RO	57639	60939	63826	70756	60824	70466	84787	73213
RS	42146	43322	43945	47437	43325	45178	55644	45272
SE1	10053	10033	10177	9955	11503	10211	9588	10318
SE2	17340	17283	17525	17151	19722	17555	16562	17783
SE3	89421	88940	89914	88280	100747	89152	86593	91766
SE4	25297	25151	25428	24991	28128	25181	24600	25978
SI	13389	14895	16542	17553	15616	20010	20444	20501
SK	29431	31054	32750	35497	32806	36065	42065	36188
TN00	0	32828	40557	40557	40557	0	0	0
TR	329298	415007	401867	417797	401867	376723	451069	377328

Table 12: Annual demand across the scenarios (TWh)

The output from the process generates an hourly demand profile for each market node across all scenarios. This report summarises demand in terms of the annual energy (TWh) for each market node as described in the following sections 1.3.6 and 0.

1.3.6. Forecast of 2030's and 2040's electricity consumption

Electricity consumption profiles per market node are an essential input to power market models. Variation in demand between scenarios provide market model outputs with valuable information on possible power flows within Europe.

The components that make up an electricity demand forecast include the following:

- Economic Growth Rates
- impact of energy efficiency measures
- new industrial demand (such as data centre demand)
- decarbonisation policies
  - the impact of electrification of transport
  - the impact of electrification of the heating sectors.

The base market node estimates for annual load (TWh) and annual consumption peak (GW) for 2030, are collected from TSOs.

TSOs provide the following data for 2030:

- normal/average annual load (TWh) and annual demand peak (GW)
- the number of Electric Vehicles
- the number of electric and hybrid heat pumps
- new industrial demand (TWh).

The scenario hourly demand profiles are created using a load profile building tool, which builds node-by-node load profiles for 34 climate years.

Sector	Scenario	Qualitative prediction
Residential and commercial sector	Sustainable Transition	Stable
	Global Climate Action	Moderate growth
	Distributed Generation	Moderate growth
Industrial sector	Sustainable Transition	Stable
	Global Climate Action	Stable
	Distributed Generation	Moderate growth

Table 13: Electricity consumption scenario assumptions

As the market model input data does not distinguish between residential and industrial demand the above table has been translated to:

Scenario	Qualitative prediction
Sustainable Transition	Low or negative demand growth
Global Climate Action	Lower growth than Distributed Generation
Distributed Generation	Moderate growth

Table 14: Aggregated electricity consumption scenario assumptions

The future energy demands for each of the top-down scenarios are computed on the basis of the TSO bottom-up data for 2020, 2025 and 2030 and is described in the following. The data used was provided from TSOs during the official data collection.

Depending on the given scenario a specific demand forecasting logic is assigned which can be found in the next table. In which energy efficiency gains are taken as an implicit factor of the estimated demand trends.

Scenario	2030	2040
Sustainable Transition	TSO data collection	Forecast based on TSO data extrapolation
Global Climate Action	-	Average value of ST2040 and DG2040
Distributed Generation	Usage of Composite Index	Usage of Composite Index

Sustainable Transition 2040 – Forecast based on TSO data extrapolation

Growth or shrinkage rates of each market nodes' electricity demand are retrieved from the TSO estimates for 2025 and 2030 and are extrapolated from 2025 to 2040 (15 years) in a second step. The reason for considering only the last 5 years lay in the buckling of many forecast curves given the TSO values provided for 2020, 2025 and 2030. For several market nodes the demand rises until 2025 and decreases afterwards (e.g. due to efficiency gains and slower EV and electrical heat pump uptake); thus it is seen unrealistically to interpolate the 2020-2030 trend which in most of these cases is still positive when averaged.

Distributed Generation 2030 and 2040 – Usage of Composite Index

The scenario Distributed Generation is estimated departing from Sustainable Transition 2030 numbers, but is tailored to regional characteristics using a Composite Index (CI). The general logic behind the CI is to amplify respectively buffer the identified demand trends between the years 2020, 2025 and 2030, as stated before. The index intends to reproduce the European variety of power sectors and their different, path-dependent evolutions.

The CI consists of the average weighted factors Demand Factor and TSO Factor, which are described below.

$$Composite\ Index = \frac{Demand\ Factor + TSO\ Factor}{2}$$

Demand Factor

The national per capita electricity demand in kWh[3] is used to define average electricity demand, which is defined as the corridor between arithmetic mean (4,829 kWh) and median (7,136 kWh). The rationale behind is that Member States with below average demand are expected to grow stronger than above average countries.

[3] EUROSTAT (2016) nrg_105: data for 2014.
http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_105a&lang=en
EUROSTAT (2016) [demo_pjan]: data for 2014.
http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=demo_pjan&lang=en

Per capita electricity demand (in kWh/year/capita)	Demand Factor
< 4,829	+ 1.5
4,829 ≤ x ≤ 7,136	+ 0.5
< 7,136	- 0.5

TSO Trend

Based on the demand trend between 2020 and 2030 of the TSO collected data, the market nodes are classified according to their predicted growth/shrinkage rates in three classes and its fine-tuned demand growth rates accordingly, so that average growth is around 0.5 % as estimated for Europe in the WEO 2016.

Classification	predicted growth / shrinkage rates	TSO Trend
Shrinkage	< 0 %	- 0.5
Stagnation	≈ 0 %	+ 0.5
Growth	0 % <	+ 1.5

After allocation of the two factors, they are equally weighted and form the CI which is used to calculate the electricity demand for each market node and given time horizon.

Based on the following equations, these derived trends are extrapolated from 2025 towards 2030 respectively 2040 (for 5 and for 15 years), as seen below.

$$For\ 2030\text{: DG2030 demand}_{Node\ A} = demand\ TSO\ collection_{2025,Node\ A} * \left(1 + \left(\frac{CI}{100}\right)\right)^5$$

$$For\ 2040\text{: DG2040 demand}_{Node\ A} = demand\ TSO\ collection_{2025,Node\ A} * \left(1 + \left(\frac{CI}{100}\right)\right)^{15}$$

Global Climate Action 2040 – Average value of ST2040 and DG2040

The Global Climate Action 2040 electricity demand values are determined by averaging the specific derived electricity demand values for Sustainable Transition 2040 and Distributed Generation 2040.

$$GCA2040\ demand_{Node\ A} = \frac{ST2040\ demand_{Node\ A} + DG2040\ demand_{Node\ A}}{2}$$

1.3.6.1. Heat pump diffusion

Heat pumps can in many situations efficiently replace oil and gas boilers with electricity[4] both as large scale industrial systems and on the domestic private consumer scale.

The use of domestic electrical heat pumps can have challenging effects on distribution grids. In highly temperature sensitive countries in cold winter peaks, one of the commonly proposed solutions is the

[4] http://vbn.aau.dk/files/77342092/Heat_Roadmap_Europe_Pre_Study_II_May_2013.pdf (last accessed on 01/10/2017 at 11h28 CET).

use of a combined technology using electricity in base load times and switching to a fossil source in order to meet peak loads[5]. These so called “hybrid heat pumps” (HHP) heat ambient air and water typically with gas instead of using ambient (ground)water or air temperature differences.

In the TYNDP 2018, hybrid heat pumps were only modelled for countries with extensive residential natural gas infrastructure which would allow their extensive application.

The upper boundary of growth rate of the diffusion of heat pump systems in the residential and commercial sector was set to 10%, which is closely in line with the growth rate estimations of the European Heat Pump Association until 2020[6].

Framing the uncertainty of hybrid heating pumps diffusion is much more challenging given the limited availability of past development rates. Thus, these values were derived using the upper boundary provided by Gas TSO with high penetration of gas in the heating market and detailed numbers for the development path of hybrid heat pumps within their scenarios.

Technology	Scenario	Qualitative prediction	Deployment rate estimated
Heat pumps (HP)	Sustainable Transition	Low growth	5%[7]
	Global Climate Action	High growth	10%
	Distributed Generation	Moderate growth	8%

Table 15: Heat pump growth rates

[5] https://setis.ec.europa.eu/sites/default/files/reports/Background-Report-on-EU-27-District-Heating-Cooling-Potentials-Barriers-Best-Practice-Measures-Promotion.pdf (last accessed on 01/10/2017 at 11h32 CET).
[6] http://www.ehpa.org/technology/heat-pumps-and-eu-targets/ (last accessed on 01/09/2017 at 10h18 CET).
[7] As the Sustainable Transition scenario represents a bottom-up scenario grounded on TSO estimates, the chosen value (5%) was calculated with the Compound Annual Growth Rate (CAGR) in-between 2020 and 2030 horizons.

Technology	Scenario	Qualitative prediction	Max share of heat pumps being hybrid
Hybrid heat pumps (HHP)	Sustainable Transition	Moderate growth	35 %
	Global Climate Action	High growth	43 %
	Distributed Generation	Very high growth	85 %

Table 16: Maximum share of hybrid heat pumps in total installed heat pumps

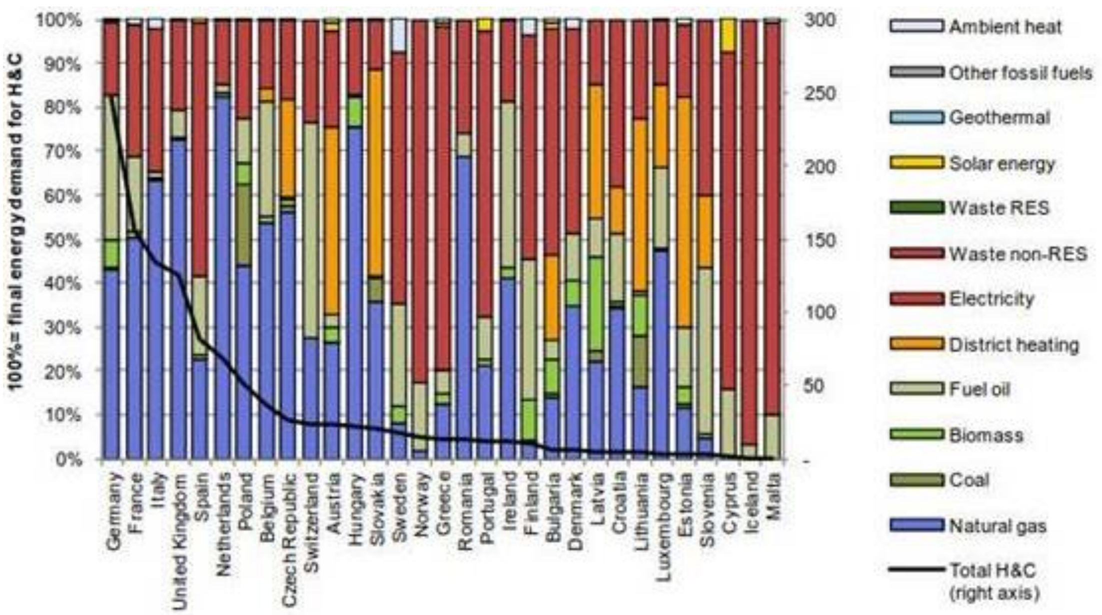


Figure 15: Share of energy carriers to cover H/C demand per country. On the secondary axes (right) the total demand per country is shown in TWh (2012)

1.3.7. Electric vehicles

The electric vehicle numbers for the scenario obtained as follows

- Sustainable Transition 2030 are collected from the TSO estimations.
- EUCO 2030 is based on figures provided by DG Energy.
- All of the other scenarios are based on the projections from the IEA EV-Outlook 2016.

The following table maps the IEA EV outlook to the 2030 and 2040 scenarios.

Scenario	Growth in EV	IEA EV-Outlook numbers
Sustainable Transition (2040)	Moderate	2040 Low
Global Climate Action (2040)	High	2040 Mod
Distributed Generation (2030 & 2040)	Very High	2030 and 2040 High

Table 17: Electric vehicle scenario alignment with IEA EV-Outlook

For Sustainable Transition 2040 the EV forecast is based on the reported numbers for 2030 and a projection of the growth after 2030 from IEA-Low.

For Distributed Generation (2030/2040) and Global Climate Action 2040 the values are set by IEA numbers, given that the TSO reported EV market share from Sustainable Transition 2030 is not higher than this.

In thousands of EVs	Sustainable Transition		Distributed Generation		Global Climate Action
	2030	2040	2030	2040	2040
Albania	24.9	57.4	29.1	70.2	47.7
Austria	537.1	1009.1	629.5	1278.6	914.7
Belgium	390.9	900.8	456.9	1102.1	748.9
Bosnia	49.8	114.8	58.2	140.4	95.4
Bulgaria	192.0	442.4	232.8	561.6	381.6
Croatia	20.0	46.1	145.9	351.9	239.1
Czech Republic	161.3	371.7	611.2	1474.4	1001.8
Denmark	86.6	131.5	198.3	334.1	253.1
Denmark	129.9	197.3	297.5	501.3	379.7
Estonia	40.0	92.2	46.7	112.8	76.6
Finland	250.0	576.1	269.4	650.0	576.1
France	3694.0	6146.8	6349.1	11667.4	8575.4
FYR of Macedonia	21.8	50.2	70.4	169.9	115.4
GB Northern Ireland	92.6	163.4	172.8	334.5	241.9
Germany	2640.0	5647.6	5400.0	12200.0	8450.0
Great Britain	4706.1	8309.9	4759.3	9212.6	10067.6
Greece	423.3	975.4	494.7	1193.4	810.9
Hungary	175.0	403.3	246.0	593.5	403.3
Ireland	168.0	296.6	313.6	607.0	439.0
Italy	470.7	1180.6	686.7	1759.3	1180.6
Italy	811.3	2034.9	1183.7	3032.4	2034.9
Italy	2287.3	5737.0	3337.2	8549.3	5737.0
Italy	355.8	892.3	519.1	1329.8	892.3
Italy	95.6	239.9	139.5	357.5	239.9
Italy	259.0	649.6	377.8	968.0	649.6
Latvia	24.0	55.3	93.1	224.6	152.6
Lithuania	34.0	78.3	117.8	284.1	193.1
Luxembourg	46.0	46.0	46.0	110.0	110.0
Norway	129.0	204.7	160.8	278.6	204.7
Norway	75.0	119.0	93.5	162.0	119.0
Norway	660.0	1047.4	822.6	1425.2	1047.4
Poland	1900.0	4378.3	0.0	0.0	4378.3
Portugal	84.5	144.1	694.8	1305.1	953.0
Romania	57.0	131.3	552.9	1333.8	906.3
Serbia	110.0	253.5	154.6	373.0	253.5
Slovak Republic	152.4	351.2	238.9	576.4	391.7
Slovenia	149.3	344.1	209.9	506.4	344.1
Spain	1000.0	1325.0	2425.0	5850.0	3975.0
Sweden	16.7	28.5	24.8	46.7	34.2
Sweden	34.0	58.1	50.6	95.2	69.7
Sweden	323.2	552.1	481.5	904.9	662.5
Sweden	106.8	182.5	159.2	299.1	219.0
Switzerland	814.6	1877.1	1145.2	3305.6	1877.1
The Netherlands	736.1	1383.0	1013.1	1852.1	1472.2
Montenegro	8.3	19.1	9.7	23.4	15.9

Table 18: Number of electric vehicles (1000s)

1.4. ENTSOG Processes

1.4.1. Reference Grid

The gas transmission grid in the TYNDP is categorised over time by a number of infrastructure levels based on existing infrastructure and projects at different maturity statuses. The reference grid for the purpose of developing TYNDP 2018 scenarios is considered to be the Low Infrastructure Level from TYNDP 2017, consisting of existing infrastructure and projects with Final Investment Decision (FID) Status. Capacity data of the infrastructure levels is provided as part of the supporting information included in the release of the Final Scenario Report.

Any gas demand that represents newly gasified areas enabled by future projects, is classified as gasification demand. This demand is not included in the baseline of the scenarios developed, and is only factored into TYNDP assessment when the applicable project exists, which in turn is dependent on the commissioning date and relevant infrastructure level.

The TYNDP 2018 Project Collection process took place during Q1 2018 and a TYNDP 2018 Project List will be issued in May 2018.

1.4.2. Natural gas indigenous production and extra-EU supply potentials

This section provides a more detailed description of the various supply sources considered in the report. It is important to remember that, except for National Production, these results don't represent fixed supply mixes in relation the main scenarios but only the range in which the different supply mixes will be assessed as part of the TYNDP simulations in order to achieve the final outcome.

1.4.2.1. Indigenous production

Indigenous production covers the national production of gas from EU countries including conventional sources and also from renewable gases including biomethane and power to gas.

1.4.2.2. Conventional sources

Conventional gas production in Europe has constantly decreased between 2010 and 2016. The evolution was not homogeneous and even if indigenous production increased slightly in some countries, the decreases observed in the Netherlands and the UK accounted for the majority of the decline in the EU over the period. The situation in the Netherlands is not only caused by depletion of gas reserves, but is also the result of several ongoing restrictions on the production of the Groningen field, introduced by the Dutch Government since 2014, in response to the earthquakes in the Groningen area.

Regarding the latest news concerning the production in The Netherlands, NL potential will be adapted for the TYNDP assessment as soon as any new official decision from the correspondent authorities is taken about Groningen, as long this one is issued in a timeline still compatible with the TYNDP 2018 deadline.

The information on EU indigenous production has been collected from TSOs. The EU indigenous production is expected to continue decreasing significantly over the next 20 years. This decrease could be slightly mitigated with the development of production fields in the Romanian sector of the Black Sea and Cyprus[8]. Next figure shows EU conventional production as foreseen by TSOs, including the one coming from Non–FID projects. Overall production could decrease by more than 60% by 2040 or even further if Non-FID developments are finally not commissioned.

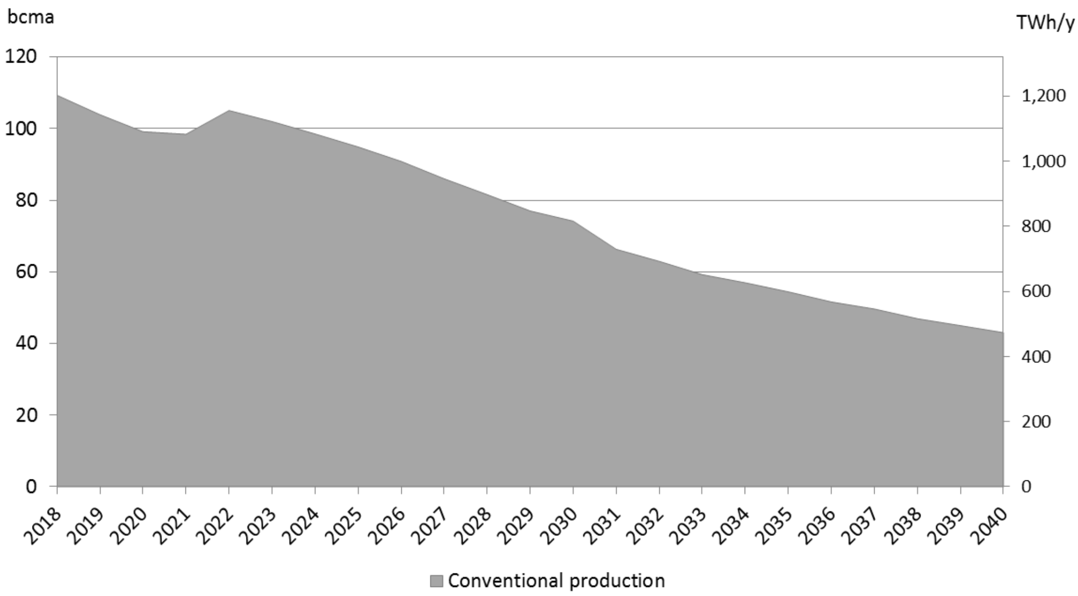


Figure 16: Potential of EU conventional production 2018-2040 (incl. Non-FID)

COUNTRY	2020	2025	2030	2040
AT	9.3	9.3	9.3	9.3
BG	6.1	15.3	15.7	15.7
CY *	0.0	116.8	116.8	116.8
CZ	1.0	0.6	0.6	0.6
DE	60.9	36.5	23.6	9.9
DK	46.9	27.8	12.2	1.4
HR	10.1	5.8	0.9	0.0
HU	6.5	4.6	4.4	3.9
IE	20.9	15.9	7.5	0.0
IT	59.0	46.5	36.6	22.7
NL	414.3	345.7	307.8	179.1
PL	27.7	27.7	27.7	27.7
RO	76.8	48.3	32.0	15.0
RO *	23.6	93.7	62.9	23.1
SK	0.7	0.1	0.0	0.0
UK	338.2	233.7	145.7	41.2
Total	**1,102.1**	**1,028.4**	**803.9**	**466.4**

* New non-FID production

Table 19: Potential EU conventional production 2018-2040 (incl. Non-FID), TWh/y

Apart from Groningen, the main uncertainties related to the evolution of the European conventional production are related to the development of the necessary infrastructures to connect new gas fields to the rest of the European gas system.

[8] *Cyprus does not have a domestic market. It is assumed that a large proportion of Cyprus production will be delivered to Europe. As it is located far from European markets there is uncertainty whether the gas will flow either as pipe or LNG.*

1.4.2.3. Renewable gases

Renewable gases include biomethane, hydrogen and synthetic methane produced with power-to-gas (P2G) technologies. They represent carbon neutral energies that can be produced continuously and injected or stored in the existing gas infrastructures.

1.4.2.3.1. Biogas

Biogas is the result of biomass degradation achieved by bacteria under anaerobic conditions, a process taking place spontaneously in nature. The biogas itself is a mixture of gas, mostly methane (from 50 to 75%) and CO_2 (25 to 50%), but also water and oxygen, with traces of sulfur and hydrogen sulfide. After drying and desulfurisation, biogas is converted to electricity and heat in cogeneration units (Combined Heat and Power – CHP) in biogas plants. The produced electricity is sold to the electricity grid, while the heat can be used on-site or transmitted to a local district heating system. The biogas production process also creates digestate, a stabilised organic matter rich in nutrients commonly used as an organic fertiliser in agriculture. The biogas production process is robust and accepts numerous substrates from animal by-products to household biowaste via energy crops and commercial waste.

The biogas industry is a mature and widespread market in Europe, with 17,662 installations distributed across the continent. The development of the industry was kick-started in the beginning of the 90s, with a gross electricity production going from biogas of 915 GWh in 1990 to 62,704 GWh in 2016. The same year, Europe included a total installed electric capacity of 9,985 MW.

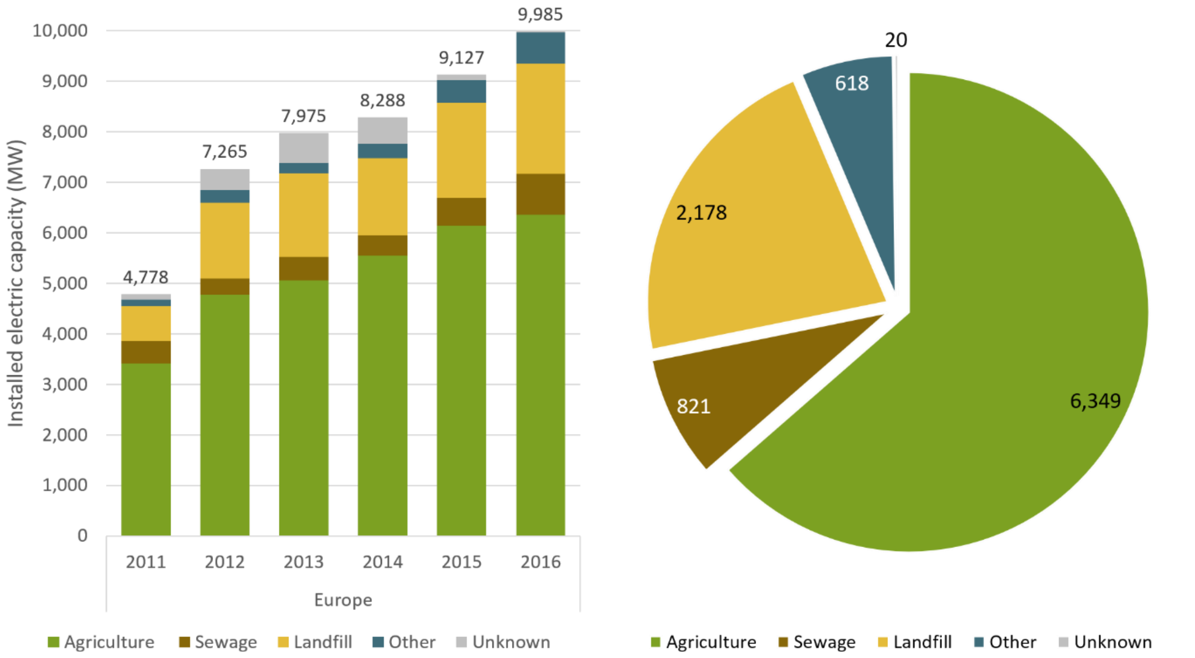


Figure 17: Evolution of the installed electric capacity per feedstock in the biogas sector (left) and its distribution in 2016 (right) in Europe

The development of the biogas sector has been exponential since the beginning of the 90s, but the number of biogas installations and the electricity production from biogas is slowly stabilising since 2012, with the addition of only 223 installations (+1%) in 2016 in Europe. This is usually for legal reasons, such as the shift to stricter environmental and climatic performances for new biogas installations within national legislations, the end of existing support schemes, or the cessation of legal support for the construction of new plants. Numerous forecasts however estimate that the biogas sector has much space to grow in Europe. Growth to achieve these technical potentials is expected to originate from new feedstocks made available to anaerobic digestion (such as cover crops), as well as from the development of the biomethane (injection into the gas grid, use as a fuel) and syngas industries.

Innovative technological pathways such as biomass gasification (syngas) and power-to-methane (e-fuel) are also expected to lead the way for the biogas industry. Biomass gasification is a technology already proved at large scale, and numerous forecasts estimate a high syngas potential, such as the recent Gas for Climate initiative[9]. The rise of power-to-methane technologies is expected to integrate the wind/solar and biogas industries by transforming renewable electricity surpluses into easily storable and injectable gas, smoothing the variations of the renewable electricity production.

1.4.2.3.2. Biomethane

Biogas can also be upgraded, a process in which the share of methane is increased to natural gas grade, in order to be injected as biomethane in the gas grid and used in natural gas applications. The total European biomethane production was 17,264 MWh in 2016, for 503 installations. A map of European biomethane installations was developed by GIE and EBA and released in January 2018, of which you can order a copy online.

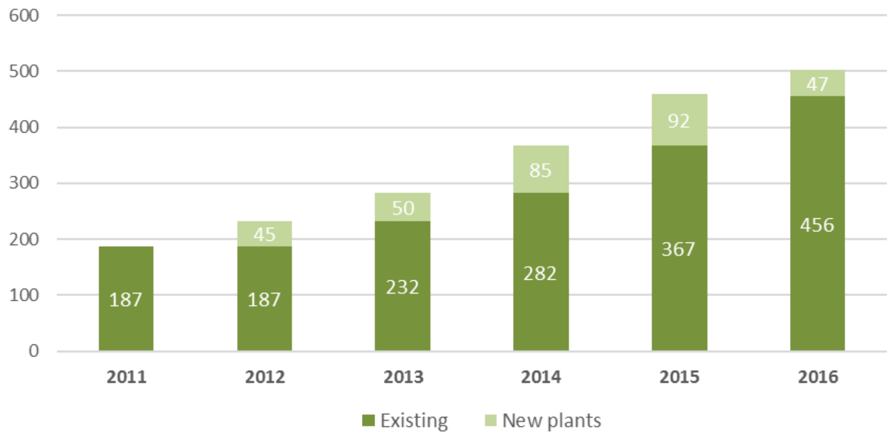


Figure 18: European biomethane plants 2016 (EBA)

Biomethane is currently rapidly increasing in Europe, going from 750 GWh to 17,000 GWh per year between 2011 and 2016. This is the result of ambitious development targets in leading EU countries such as France (252 projects being developed, for an expected production increase of 5 TWh) and the UK. A clear trend to use biomethane as a fuel to aid the energy transition in the sector is also clear in Europe, such as in Scandinavian countries, Estonia and Italy. The latter enjoys the largest EU CNG cars fleet and updated its biomethane decree in 2017 which unlocks subsidies for 1.1 bcm of biomethane a year. Other countries, such as Switzerland and Austria, are looking into upgrading the existing biogas installations to switch the national production from biogas to biomethane, leading the way for other EU countries.

[9] https://gasforclimate2050.eu/

> Biomethane supply potentials

Biomethane potentials only cover the share of biogas upgraded to biomethane as only this proportion can be injected into the distribution or transmission grids. According to the TSO estimates in the Distributed Generation scenario, the largest share of biomethane injection in 2040 will take place in Italy, France, United Kingdom and the Netherlands, accounting for around 90% of biomethane supply in Europe.

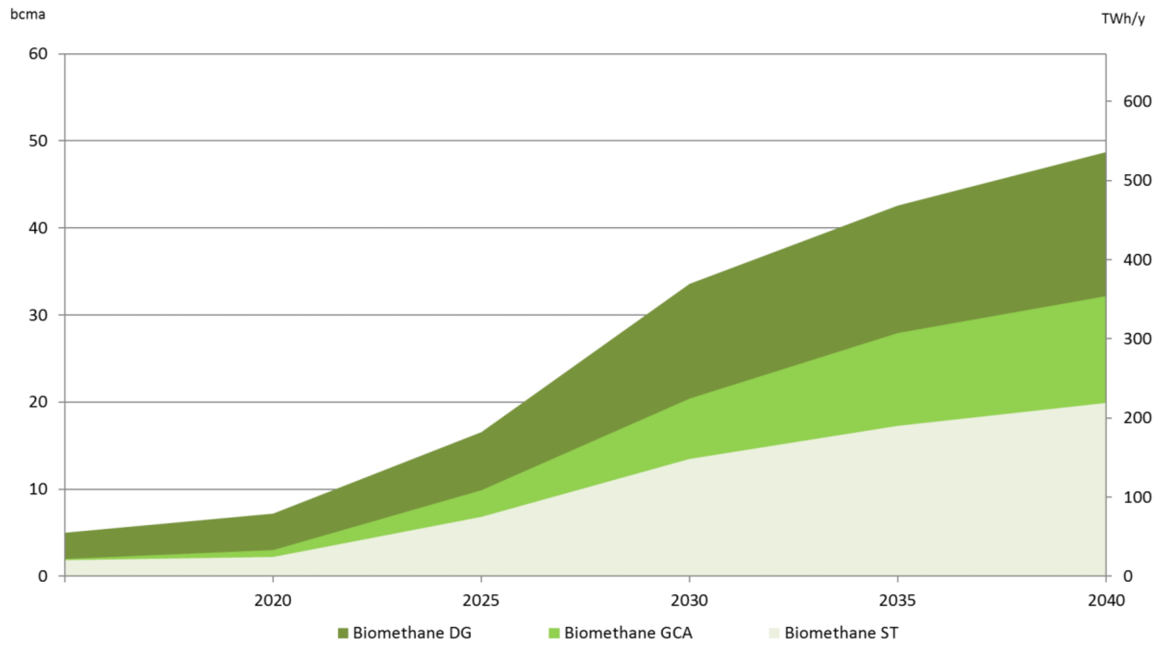


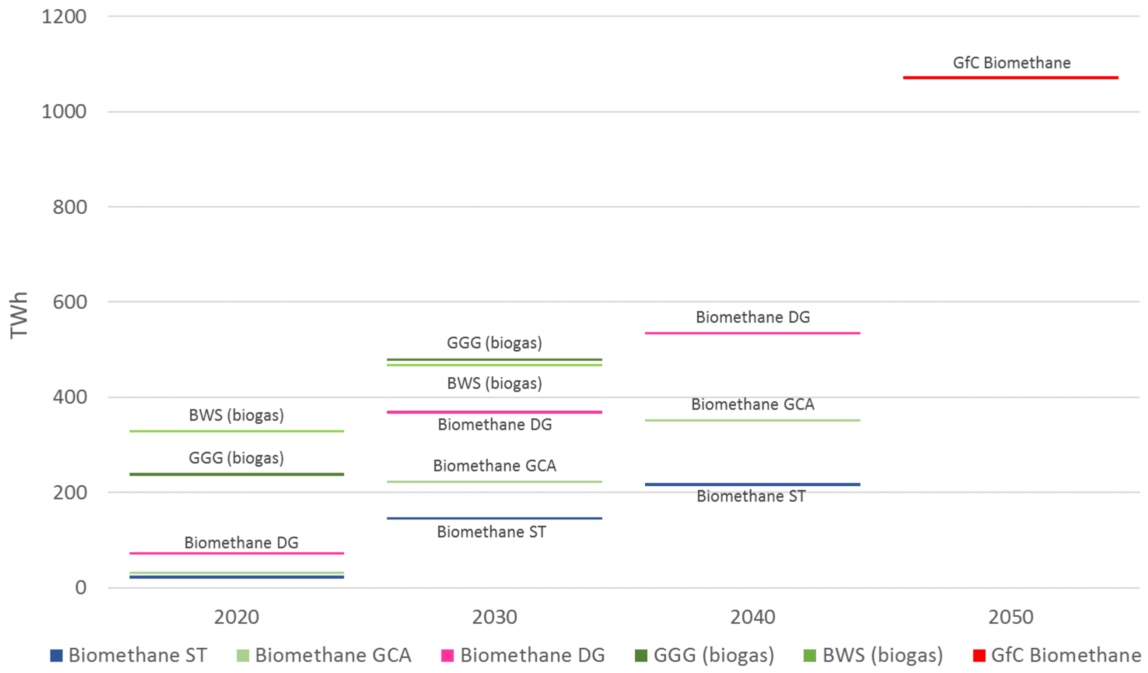
Figure 19: Potential EU biomethane production 2018-2040

TWh/y	2020	2025	2030	2040
Biomethane DG	79,4	181,7	369,4	536,3
Biomethane GCA	33,1	108,7	224,6	353,8
Biomethane ST	24,7	75,1	148,3	219,2

Table 20: Potential EU biomethane production 2020-2040 Global Climate Action, TWh/y

The three biomethane scenarios have been updated in the Final Scenario Report following input received during the draft scenario report workshop and public consultation feedback.
Firstly, ENTSOG collected additional data from TSOs along with the clarification that the levels of biomethane development should cover production and injection at both the TSO and DSO grid level.
For countries unable to provide production values lower than TSO level, a top-down methodology was created by ENTSOG, based on publicly available information on the current national development and future perspective and potential level assumptions of biomethane in the EU.

Comparison between ENTSOG scenarios and other sources forecasts and projections:



Biogas and biomethane forecasts for Europe in 2020, 2030, 2040 and 2050

Legend: ENTSOG: TYNDP 2018 Scenarios Report, GGG: Green Gas Grids final report (2014), BWS: Biogas Waste Streams – CE Delft 2017, GfC: Gas for Climate initiative (Ecofys) (2018)

1.4.2.3.3. Power-to-gas

Power-to-gas (P2G) is the name for a technology and process that converts electrical power into a gaseous energy. Through this process, the excess production of renewable electricity which would normally be curtailed or low lost electricity, can be used to produce hydrogen by electrolysis. This hydrogen can also go through a methanation process, using a source of CO2 to create synthetic natural gas (SNG) which can be injected into the transmission without any new requirements or modifications to the existing infrastructure. Production figures for P2G within TYNDP18 are of such a level that the energy could relate to SNG or hydrogen without any impact to the gas transmission system. Studies are currently being completed regarding hydrogen levels within gas networks which will be factored into future scenario processes if or when P2G plays a greater role. The EBA estimate that using the CO_2 produced based on the current biogas production levels, roughly 210 TWh of renewable electricity could be turned to hydrogen and then 'methanised' and injected into the natural gas grid.

P2G does not only offer the possibility to store renewable energy but also to transport it over long distances by using the gas infrastructure. This source of green gas can be used to decarbonise sectors that will struggle to move to electrification. It also has the potential to provide a demand side balancing mechanism to the power system, plus could enable the installed capacity of renewable power generation to increase, along with the overall usage of renewable sources in the energy mix. P2G (power-to-gas including by hydrogen or methane injection) is a technology allowing to foster the convergence of energy systems, utilising the respective strengths of each.

Methodology: Based in the P2G figures provided to ENTSOG by GRT Gaz for France and Energinet for Denmark, P2G potential technical capacities were estimated for the other countries by assessing the P2G capacity in the assumptions for the solar and wind capacities estimated and fixed in 2030 and 2040 for GCA and DG. The production per country is estimated taking into account the outcome of the electricity curtailment and the marginal price output in 2030 and 2040 of GCA and DG scenarios.

The potential for P2G has been based on the output of the ENTSO-E market models. Further optimisation loops would be required in order to fully assess the full impact of P2G capacity on the respective networks. When assessing the GCA generation using the 2030 Reference Grid results in curtailed energy which could be utilised by P2G installations. However, part of this curtailment could be avoided with additional electricity interconnectors.

Another aspect involves taking into account the price of natural gas and CO_2, producing renewable gas as a product for less than 30 eur/MWh, which could provide a business case for P2G if sites can be operated for 3,000 hours per year.

General assumptions:

- efficiency AC power to synthetic CH4: 65%
- average running hours: 3,000
- production electricity price under 30 eur/MW.

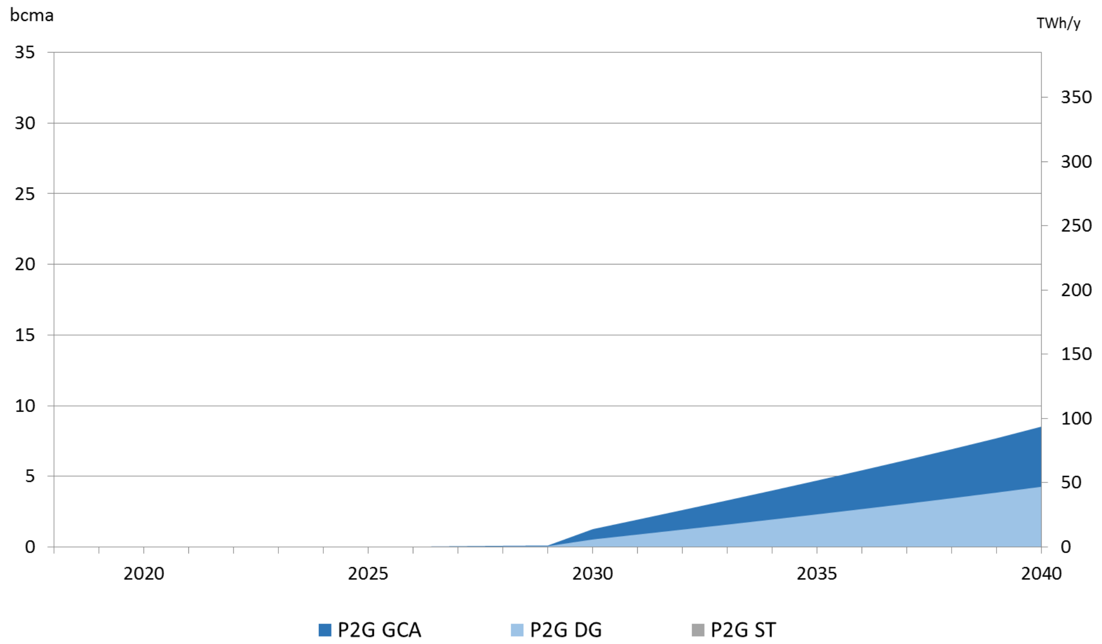


Figure 20: Potential EU power-to-gas production 2018-2040

TWh/y	DG	
COUNTRY	2030	2040
AT	0.1	0.9
BE	0.1	1.2
BG	0.0	0.4
CH	0.1	0.9
CZ	0.1	0.7
DE	1.4	9.4
DK	0.1	1.0
EE	0.0	0.2
ES	0.7	4.3
FI	0.0	0.6
FR	0.7	5.7
UK	0.6	4.9
GR	0.1	1.5
HR	0.0	0.4
HU	0.1	0.5
IE	0.1	0.6
IT	0.5	5.6
LT	0.0	0.3
LU	0.0	0.0
LV	0.0	0.2
NL	0.3	1.5
PL	0.3	3.3
PT	0.1	0.9
RO	0.1	1.2
SE	0.1	1.0
SI	0.0	0.2
SK	0.0	0.3
Total	5.9	47.8

TWh/y	GCA	
COUNTRY	2030	2040
AT	0.3	1.0
BE	0.4	3.3
BG	0.2	0.4
CH	0.0	1.3
CZ	0.1	0.6
DE	4.1	22.5
DK	0.1	1.3
EE	0.0	0.7
ES	1.8	11.5
FI	0.1	1.3
FR	1.4	11.3
UK	1.4	7.7
GR	0.4	3.8
HR	0.1	0.3
HU	0.1	0.5
IE	0.1	0.9
IT	1.4	7.7
LT	0.0	0.7
LU	0.0	0.1
LV	0.0	0.1
NL	0.4	6.5
PL	0.4	2.3
PT	0.2	2.6
RO	0.3	3.9
SE	0.4	2.2
SI	0.1	0.2
SK	0.0	0.2
Total	13.9	95.1

Table 21: Potential power-to-gas production 2030-2040 DG and GCA

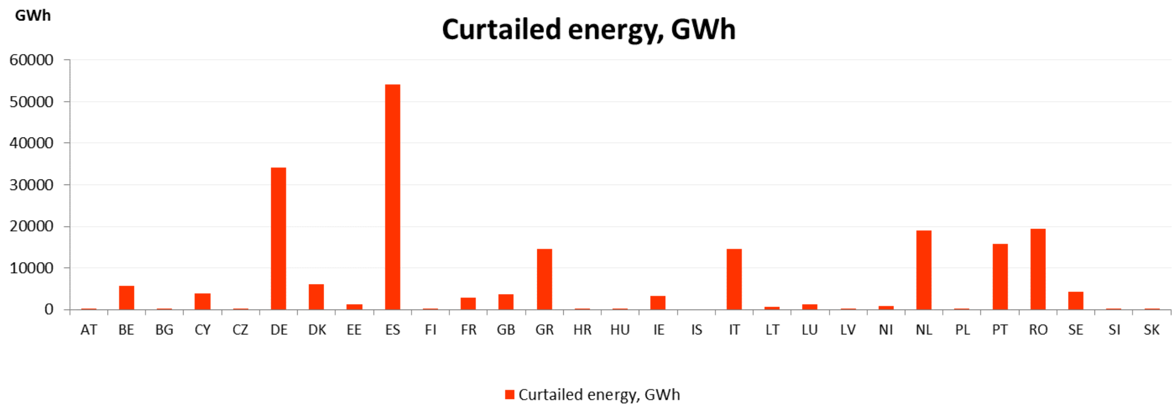


Figure 21: Curtailed energy 2040 GCA

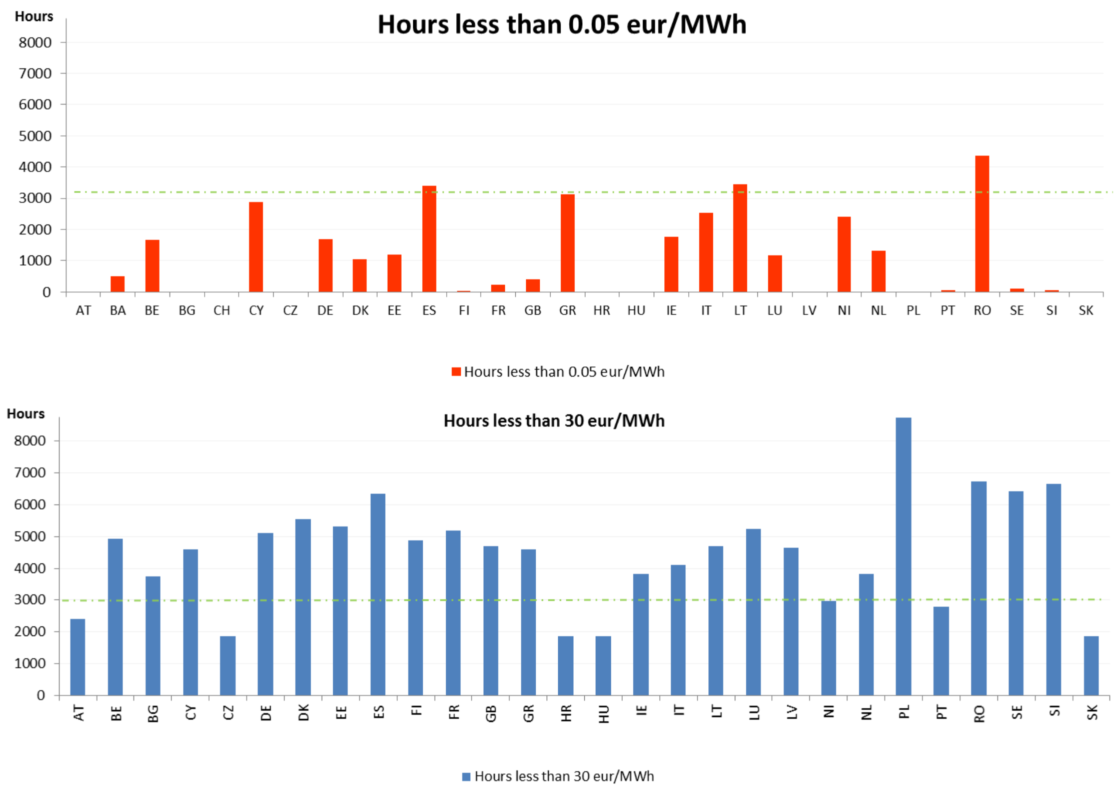


Figure 22: Number of hours marginal price under 0.05 and 30 eur/MW 2040 GCA

The trend lines of this data, along with a recently published study Gas for Climate (Ecofys 2018) which assesses the potential P2G produced across the EU, are displayed in figure 23. Other sources not represented in the graph go even further and estimate a very high P2G potential in the long term. In particular, "Innovative Gas" scenario from the Primes Scenario Study conducted for Eurogas (2016) considers a very high volumes of P2G production in 2050[10].

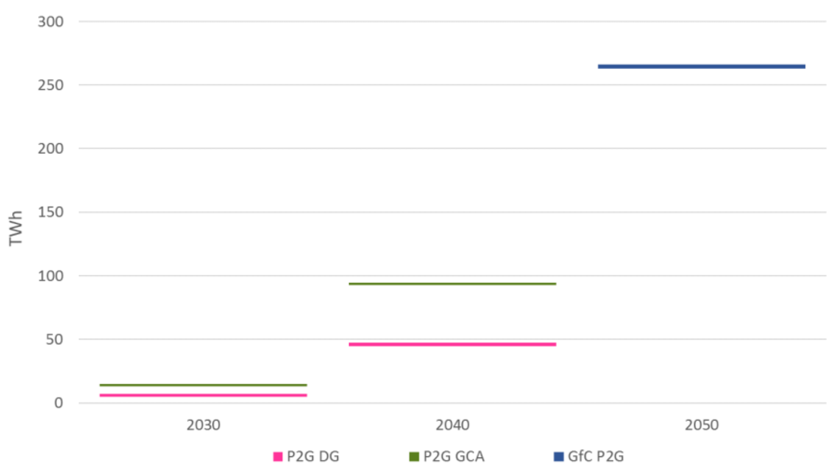


Figure 23: Power-to-gas forecasts for Europe in 2030, 2040 and 2050
Legend: ENTSOG: TYNDP 2018 Scenarios Report, GfC: Gas for Climate initiative (Ecofys) (2018)

10 https://www.entsog.eu/public/uploads/files/publications/Events/2017/tyndp/EUROGAS%20Renewable%20Gas%20Policy.pdf

1.4.2.4. Russia

The Russian Federation is currently the main gas supplier of the EU, providing by pipeline 143 bcm (1,573 TWh) in 2016[11], more than 30% of EU supply share. It is expected to remain a major import source over the whole time horizon of this Report.

> **Reserves**

Russia has the second largest proven gas reserves in the world, behind Iran, with 32,271 bcm at the end of 2016[12], increasing by around 14% between 2000 and 2016. According to Gazprom most of the production and reserves are located in the Ural Federal District, with significant reserves also in the continental shelf.

> **Production**

Russia has been the second largest natural gas producer of the world in 2016 behind the United States of America with 579.4 bcm.

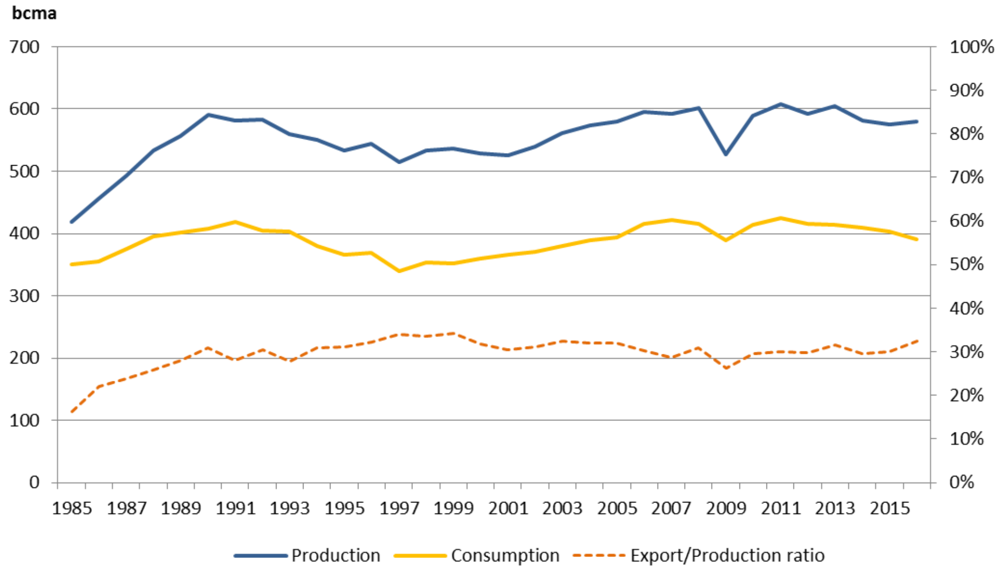


Figure 24 - Natural gas production and demand of Russia (source BP statistical review 2017)

In the period 2005-2016 the natural gas production of Russia has remained relatively stable, except for in 2009 with a decrease that could be linked to the economic down-turn and the Ukraine transit disruption, reaching even more than 600 bcm some years. Russia has its own domestic demand that can influence its export potential. This internal demand of Russia has remained above 400 bcma since 2011 but with a stable descending trend down to 391 bcm in 2016.

> **Exports**

Gas is exported to Europe through three main pipelines[13] :

- The Ukrainian route is the largest gas pipeline route from Russia to EU (enter IPs to Slovakia, Hungary, Poland, Romania) transiting through Ukraine. The total annual capacity is around

[11] *BP statistical review of world energy 2017*
[12] *BP statistical review of world energy 2017*
[13] *Source: Gazprom Export website*

150 bcma[14]. The Urengoy-Pomary-Uzhgorod pipeline, which is a part of the route, entered into operation in 1967.

- Yamal-Europe I: Entered in operation in 1994 and transmits gas along 2,000 km to Poland and Germany via Belarus. Its annual capacity is around 33 bcma.
- Nord Stream: Twin offshore pipeline across the Baltic Sea with the first line established in 2011, and the second one in 2012. It transmits gas along 1,220 km between Vyborg (Russia) and Greifswald (Germany) with two lines of 27.5 bcma each.

On April 2017 the financing agreements for the Nord Stream 2 gas pipeline project was signed. Similar to the first two strings, the new ones will be laid from the Russian coast via the Baltic Sea to Greifswald. The capacity of the new gas pipeline will reach another 55 bcma and it is expected to enter service by the end of 2019.
Also, TurkStream construction commenced on May 2017 in the Black Sea, near the Russian coast. The offshore part of the pipeline will reach a maximal depth of 2,000 metres and a length of 910 kilometres to supply Turkey and neighbouring EU region with 31.5 bcma.

Other export gas pipelines of Russia bring gas to other non-EU markets:

- Blue Stream: A 1,210 km-long gas offshore pipeline directly connecting Russia to Turkey across the Black Sea. It came on line in 2003 and its annual capacity is around 16 bcma.
- North Caucasus: Carries Russian gas to Georgia and Armenia and its annual capacity is around 10 bcma.
- Gazi-Magomed-Mozdok: It traverses 640 km through Russia and Azerbaijan. Initially this pipeline was used to export Russian gas to Azerbaijan, but it has been reversed and from 2010 it can carry 6 bcma of gas from Azerbaijan to Russia.

The largest recipients of Russian gas via pipeline in the European Union are Germany and Italy. In 2016, these two countries imported almost half of the Russian gas exports into the EU. Outside the European Union the largest recipients of Russian gas were Turkey (23.2 bcm) and Belarus (16.6 bcm).

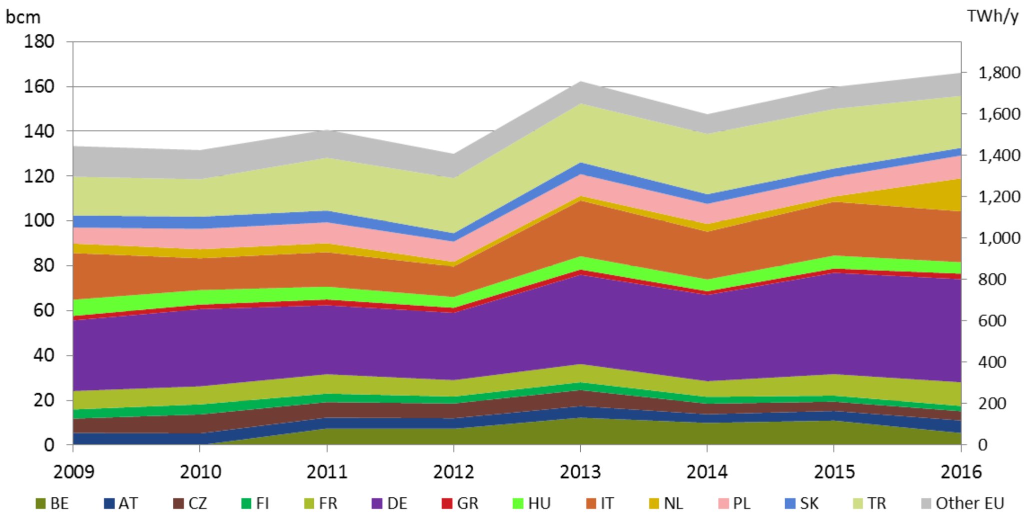


Figure 25 – Russian natural gas trade movements by pipeline, source BP statistical reviews 2010-2017)

[14] *Source:* UTG.ua

Russia is extending its interest also to eastern markets and signed a supply contract with China to deliver 38 bcma of natural gas as of 2020 via the 4,000 km long Power of Siberia pipeline that runs to the Russian-Chinese border with the design capacity of 61 bcma.

Besides the gas exports via pipeline, Russia is also an exporter of LNG. The Sakhalin liquefaction plant was commissioned in 2009 and in 2016 Russia exported 14 bcm of LNG, the majority of which was exported to Japan and South Korea. However, it is still a small amount in comparison to the EU pipeline-bounded gas exports. The Yamal LNG plant could increase the LNG exports of Russia to Europe; it will be built in three phases which are scheduled from start-up in 2017 to 2019. The project will be able to produce around 22.6 bcma of LNG which will be probably shipped to Asia-Pacific and European markets.

The future of EU imports of Russian gas will basically depend on the European demand level, on the competition from other big consumers in Asia to import Russian gas and the amount of investment in the upstream sector.

1.4.2.5. Norway

Norway is currently the second largest gas supplier of the EU and in 2016 provided gas deliveries via pipeline of 110 bcm (1,210) TWh. It is expected to remain a key import source. Contrary to Russia, Norway has no domestic demand that could influence its export potential, however, there is still uncertainty over the volume of Norwegian gas that can be produced from existing fields which are in decline. This means that new exploration, production and upstream pipeline investments are required to maintain the volumes produced currently. The potential for this development may also vary depending on market conditions.

As shown in the next table, Norwegian gas is exported via a well-developed offshore pipeline network that connects to Germany, UK, France, the Netherlands and Belgium.

Pipeline	Country	Capacity (M sm3/d)
Europipe	Germany	46
Europipe II	Germany	71
Franpipe	France	55
Norpipe	Germany, The Netherlands	32
Tampen Link	UK	10-27
Vesterled	UK	39
Zeepipe	Belgium	42
Langeled	UK	72-75
Gjøa Gas Pipeline	UK	17

Table 22 - Export capacity of the GASSCO offshore system (source GASSCO website)

In addition to the direct import countries shown in table 3 above, the Norwegian gas is also transited through the pipeline network across Europe (as shown in next figure).

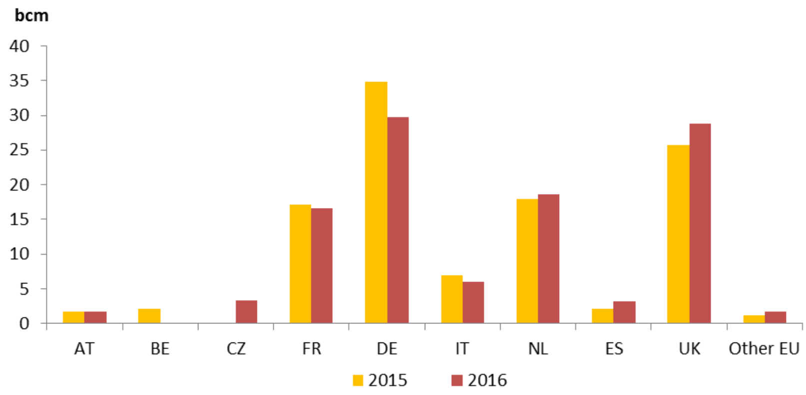


Figure 26 Norwegian pipeline exports by destination in 2015-2016 (source BP Statistical Review 2017)

> **Reserves**

Norway has been supplying natural gas to Europe for more than 40 years since production began in the early 1970s. Since then, the development of new fields has enabled the continuous increase of gas volumes exported by Norway. However for the past decade the sold and delivered volumes have increased faster than new discoveries have progressed (Reserves and contingent resources[15]). Roughly half of the reserves still remain but the overall production could fall below current levels during the 20-year time horizon.

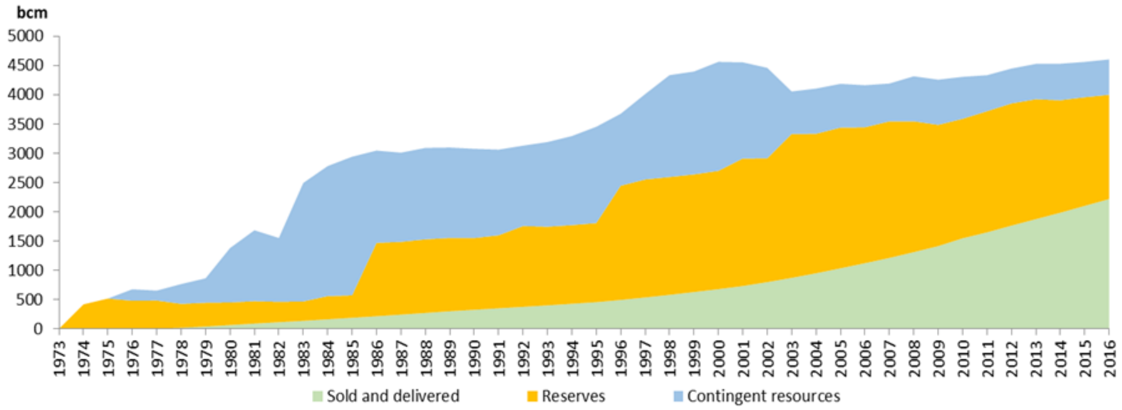


Figure 27 - Evolution of Norwegian gas reserves 1973-2016 (source Norwegian Petroleum Directorate)

One of the main challenges for Norway is to decide about the most beneficial way to export the future production. It is not decided yet whether to expand the offshore network to connect new fields to the existing grid and export this production to Europe or to export LNG globally. However, for this solution to materialise, strong signals from the European market are required.

1.4.2.6. Algeria

Algeria is one of the main producers in Africa and currently the third largest gas supplier to Europe by pipeline and also when considering both pipeline and LNG. In 2016[16] Algerian pipelines provided to Europe around 32.5 bcm (358 TWh), around 8% of the EU supply share. Algeria is expected to play an important role as gas exporter also in the future. However the availability of Algerian gas will depend

[15] *Contingent resources mean the estimated recoverable volumes from known accumulations that have been proven through drilling but which do not yet fulfil the requirements for reserves.*

[16] *BP statistical review of world energy 2017*

on future production developments and competition between pipeline gas and the global LNG market.

> Reserves

With its 4,500 bcm (49,500 TWh) of proven natural gas reserves Algeria ranks in the top ten of countries with the largest gas reserves in the world and is the second largest in Africa after Nigeria. More than half of the reserves (2,400 bcm, 26,400 TWh) are located in the centre of the country to the northwest, in the Hassi R'Mel field. The rest of the reserves come from fields situated in the Southern and South-eastern parts of the country. Besides that, Algeria holds vast untapped unconventional gas resources. According to an EIA study[17] Algeria is after China and Argentina the third-largest country worldwide with 20 Tcm of technically recoverable shale gas resources.

> Production and Consumption

Since some of the Algerian largest gas fields have begun to deplete, Algeria aims to bring new gas fields on stream but many of those projects have been postponed because of delayed governmental approval, difficulties in attracting investment partners and technical problems. Algeria's state energy producer Sonatrach Group plans to increase output of natural gas and crude oil by 20% in the next four years as new projects start up.

Project name	Partners	Output (bcma)	Start year
In Salah (Expansion)	BP/Sonatrach	14.0	2016
Touat	Engie/Sonatrach	4.3	2016
Reggane Nord	Repsol/Sonatrach/DEA/Edison	4.3	2017
Timimoun	Total/Sonatrach/Cepsa	1,8	2017
Ahnet	Total/Sonatrach/Partex	3.9	2018
Hassi Ba Hamou	Sonatrach	1.4	2018
Hassi Mouina	Sonatrach	1.8	Tdb
Isarene (Ain Tsila)	Petroceltic/Sonatrach	3.6	2018
Tinhert, Illizi basin	Sonatrach	9.3	2018
Menzel Ledjmet SE	Sonatrach	4.3	2019

Table 23– Algeria's upcoming natural gas projects, source EIA 2016, country report Algeria.

Natural gas production shows uncertainty in the short term and may recover in the mid-term. On the other hand, domestic gas consumption in Algeria is increasing and shows an ongoing upward trend that could influence its export potential.

[17] *Technically Recoverable Shale Oil and Shale Gas Resources, September 2015*

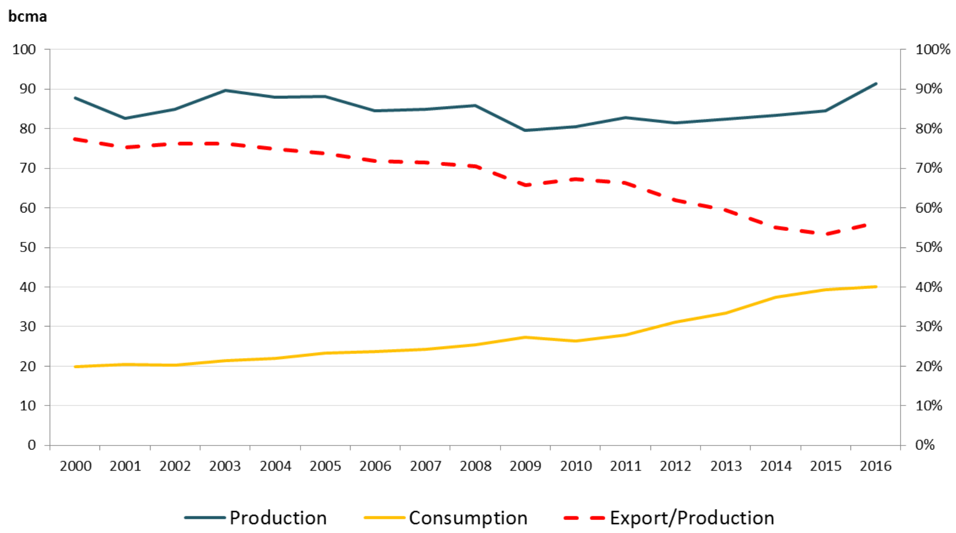


Figure 28 – Algerian dry natural gas production and consumption (source BP Statistical Review 2017)

> Exports

Pipelines

Gas is exported to Europe via three main pipelines crossing the Mediterranean Sea:

- **Pipeline Enrico Mattei** (GEM), it came on line in 1983 and transports gas along 1,650 km from Algeria to Italy via Tunisia. According to Sonatrach, its capacity is around 33 bcma.
- **MEG pipeline** came on line in 1996 and transports gas along 520 km to Spain via Morocco. Its capacity is around 13 bcma
- **MEDGAZ pipeline** came on line in 2011 and transports gas along 200 km onshore and offshore, from Algeria to Spain. Its capacity is around 9 bcma.

In 2016 Algeria exported 32.5 bcm to Europe via pipeline: 53% to Italy, 36% to Spain, and 11% to other EU countries via either Spain or Italy.

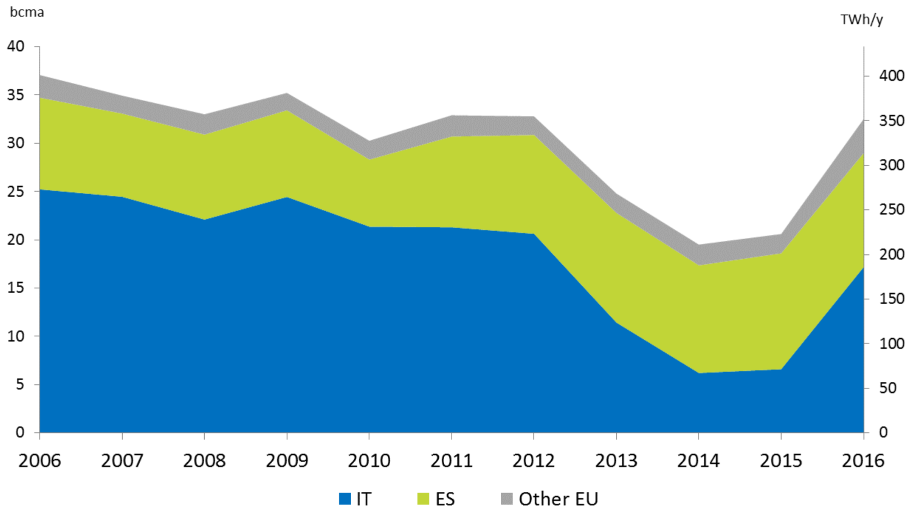


Figure 29 Algerian pipeline gas exports to Europe (2006-2016). Source BP Statistical Review 2017

With the commissioning of the MEDGAZ pipeline in 2011, Algerian exports to the Iberian Peninsula increased while flows towards Italy declined from 2013 to 2015 due to the renegotiation of long-term contracts between ENI and Sonatrach.

This represents the challenge for Algeria of developing gas production facing both national demand and export expectations.

1.4.2.7. Libya

Libya is currently the smallest gas supplier of the EU via pipeline. In 2016 it provided to Europe around 4.4 bcm (48 TWh), 1% of the supply share. This is expected to remain almost unchanged along the time horizon of this Report.

> Reserves

With its 1,500 bcm[18] (16,500 TWh) of proven natural gas reserves Libya ranks among the African countries with the largest gas reserves of the continent. Prior to the civil turmoil, which has continued since 2011, new discoveries and investments in natural gas exploration had been expected to raise Libya's proved reserves but for the moment this has not occurred.

> Production

Most of the country's production is coming from the onshore Wafa field as well as from the offshore Bahr Essalam field. Production grew substantially from 5.5 bcm (59 TWh) in 2003 to nearly 17 bcm (187 TWh) in 2010. In 2011 Libyan production was almost entirely shut down due to the civil war. Compared to 2010, more than a 50 % drop was registered, with the production decreasing to 8 bcm (88 TWh). According to BP Statistical Review, natural gas production recovered to 12 bcm in 2015 but decreased again last year to approximately 10 bcm (110 TWh/y) in 2016.

> Exports

Piped exports are transported via the Green Stream pipeline which came online in 2004. This 520 km offshore pipeline connects Libya to Italy through Sicily. This infrastructure has a total capacity of around 12 bcma.

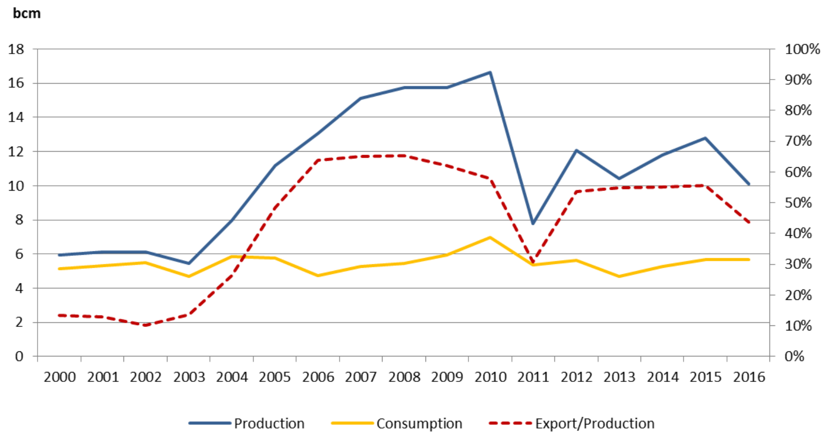


Figure 30 - Libyan gas production, consumption and export ratio 2000-2016. Source BP Statistical Review 2017.

[18] *BP Statistical Report 2017*

From March to mid-October 2011 Libyan exports to Italy were completely interrupted due to the civil turmoil. Exports soon recovered in 2012 to 6.5 bcm and stayed relatively stable the years after until last year 2016 when it dropped to 4.4 bcm.

In 1971, after the United States and Algeria, Libya became the third country in the world to export liquefied natural gas. Processed in Masra El-Brega LNG plant, LNG was mostly exported to Spain but the plant was damaged in 2011 and since then Libya has not exported LNG again.

1.4.2.8. Azerbaijan

> **Reserves**

Azerbaijan's proven reserves amount to roughly 1,100 bcm (12,100 TWh)[19]. The vast majority of these reserves come from the Shah Deniz field which turned Azerbaijan into a net exporter of natural gas in 2007. Besides that, gas is also produced from the Absheron and Umid fields. As it is shown in the next figure, domestic consumption has been stable for the past decade. Around half of the country's natural gas consumption is currently for power generation and it could further increase if Azerbaijan continues to install new gas-fired power plants.

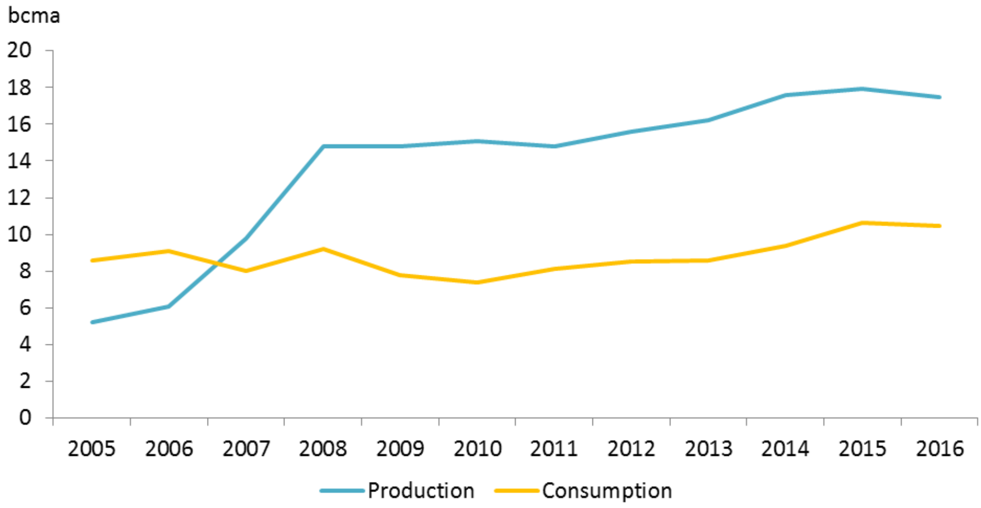


Figure 31 - Azerbaijan's dry natural gas production and consumption 2005-2016. Source BP Statistical Review 2017

Most of Azeri gas is exported to Turkey via the South Caucasus Pipeline from Baku to Erzurum as the main export pipeline. Some volumes are also exported to Russia via the Gazi-Magomed-Mozdok Pipeline and to Iran via the Baku-Astara Pipeline.

Shah Deniz Field

The potential exports of Azeri gas to Europe are closely linked to the development of this field. Discovered in 1999, it holds approximately 1,000 bcm (11,000 TWh) of natural gas reserves and its development is undertaken by a BP-led consortium. Gas production began in early 2007 and it has increased since then, reaching a production of almost 10 bcm (110 TWh/y) last year 2015[20]. Phase 2 will add another 16 bcma (176 TWh/y) of gas production with the first deliveries estimated in 2019, of which 6 bcma (66 TWh/y) are already contracted by Turkey.

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[19] *Source BP Statistical Review 2017*

[20] *EIA Country Analysis Brief: Azerbaijan, June 2016*

The additional 10 bcma (110 TWh/y) are contracted by Southern Europe countries expecting supply via Turkey through the Trans Anatolian Pipeline (TANAP) and Trans Adriatic Pipeline (TAP) projects, in combination with the extension of the South Caucasus Pipeline, which are planned to provide gas to Europe by mid-2019.

1.4.2.9. LNG

LNG enables the connection of Europe to the global market and a large number of producing countries in the Middle East, the Atlantic (including the Mediterranean) and the Pacific basins. It gives access to reliable and diversified supply offering the shippers arbitrage opportunities at a global scale between different sources and regional markets.

> **Liquefaction vs. regasification capacity**[21]

As shown in the next figure, in 2016 the regasification capacity remains more than twice that of the liquefaction capacity.

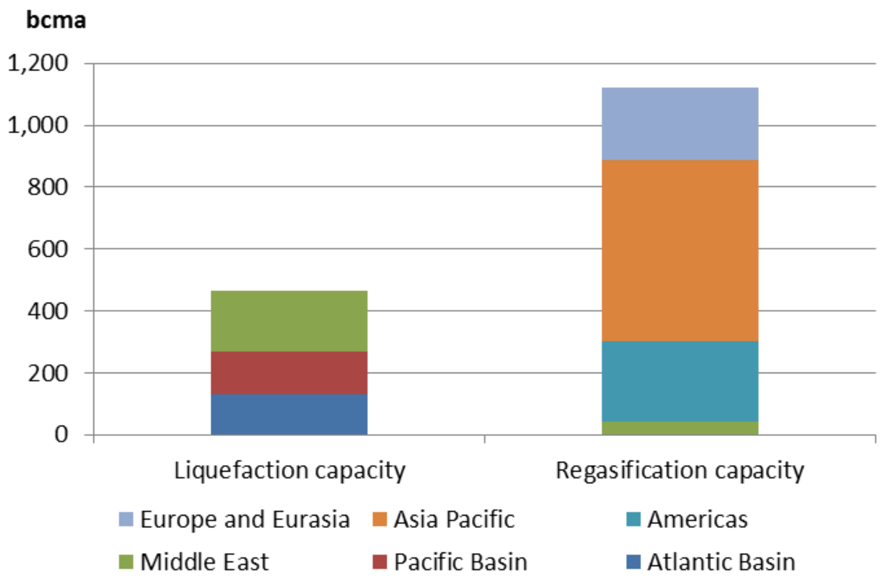

Figure 32 - Liquefaction vs. Regasification capacity. Source GIIGNL 2017

- **Regasification capacity**

The regasification capacity was expanded in 2016 by 44 bcma with eleven new terminals commissioned around the world and five expansion projects were also completed, four in Asia and one in Argentina. Additionally, there are nineteen terminals currently under construction and also seven expansion projects with a total regasification capacity of 118 bcma, 70% of which (82 bcma) are located in Asia.

[21] *Liquefaction capacities are converted from MTPA. The volume and energy content depend on the composition and the reference conditions of the LNG. The following has been considered: 1 MTPA (liquid volume) = 1.37 bcma (gas volume)*

- **Liquefaction capacity**

The existing liquefaction capacity increased by around 49 bcma in 2016 and another 148 bcma of new liquefaction capacity is currently under construction, mainly based in the United States (79 bcma) and Australia (37 bcma), demonstrating that the gap shown in the previous figure might keep on shrinking during the following years. Moreover, two new FIDs were also taken during 2016, one located in the United States, and another one in Indonesia.

> LNG production

Global production reached its historical maximum level of 342 bcm (3,762 TWh) in 2016, recovering after decreasing in 2012. Since 2001, production has more than doubled. The growth has been more significant in the Middle East where LNG production has been multiplied by four. In the same period the LNG production in the other regions grew as well but to a lesser extent.
The different evolutions followed by the three 47% market share in 2016, while Middle East and Atlantic basins shares has been reduced to 36% and 17% respectively .

Figure 33: Evolution of LNG production by basin 2001-2016 (source BP statistical reports 2002-2016)

- **Atlantic basin**

The LNG production in the Atlantic basin reached its maximum in 2010 with 83.5 bcm (918 TWh), since then it decreased by 30% to 57.3 bcm. In 2016, the biggest Atlantic basin LNG producer was Nigeria (23.7 bcm), followed by Algeria (15.9 bcm) and Trinidad and Tobago (14.3 bcm).

- **Middle East**

The LNG production in the Middle East showed a steady increase until 2009. The production increased sharply in 2010 and 2011 thanks to the commissioning of new liquefaction trains in Qatar. Since the peak of 134 bcm in 2013, the evolution of this basin has steadily decreased to 122 bcm (1,342 TWh) in 2016. The production in the Middle East has been mainly dominated by Qatar over the years, reaching a market share of 85% (104 bcm) in 2016. Other producers in the region are Oman and Arab Emirates, both with market shares below 10%.

- **Pacific basin**

The LNG production in the Pacific basin reached a maximum in 2016 with 162 bcm (1,782 TWh). Australia has experienced a substantial increase in LNG production over the last few years, reaching a market share of 35% (57 bcm) of the Pacific basin in 2016, followed by Malaysia with 20% (32 bcm) as the main LNG producing countries in the Pacific basin.

> LNG imports

The next figures show the clear dominance of Asia Pacific in the evolution of the breakdown by geographical area of LNG imports for the period 2001-2016. In this period the share of Asia Pacific in the LNG market has oscillated between 62% and 75%. Far from these shares, the second main LNG market has been Europe (including Eurasia). Their maximum share of the global LNG imports was reached in 2009 with 29% before dropping down to 17% in 2015. Since 2010 the American markets have compensated each other with a simultaneous decrease of North American imports and an increase of South American imports.

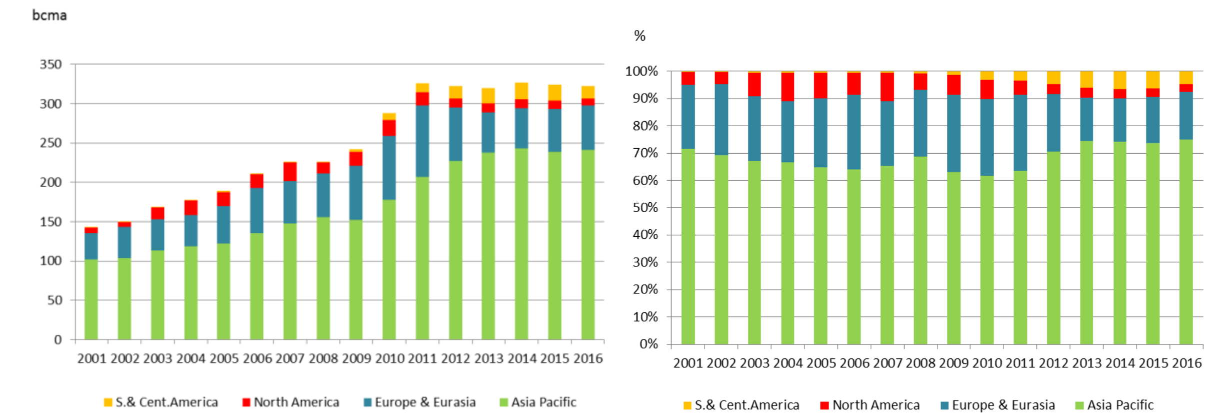

Figure 34: Evolution of LNG imports. Breakdown by geographical area, 2001-2016 (BP statistical reports 2002-2017)

- **Asia Pacific**

The Asia Pacific gas market is strongly dominated by Japan and South Korea. Japanese LNG imports grew from 2011 following the nuclear accident in Fukushima, reaching 121 bcma in 2014. In 2016 Japan showed a market share of 45% (108 bcm) followed by South Korea with 18% (44 bcm). The remaining countries in the region, like China, India and Taiwan, showed a sharp increase in consumption in the last few years, which is expected to continue in the future.

- **North America**

From 2001, the North American market was limited to the US, where strong growth was expected to be met by increasing imports. After the shale gas revolution, leading to a decrease of US LNG imports since 2007, 22 bcm dropped to 2.5 bcm last year. Mexican LNG imports started in 2006 and accounted for 68% (6 bcm) of the LNG demand of the region in 2016.

- **South and Central America**

Until 2008 only small volumes were imported to Puerto Rico and Dominican Republic. Since 2008 Chile, Brazil and Argentina have become LNG importers. In 2016 Argentina (5.2 bcm) and Chile (4.3 bcm) account together for two thirds of the market and Brazil has a market share of 19% (3 bcm).

- **EU and Turkey**

After a period of high growth, the LNG consumption fell sharply by 48% in 2016 when compared to the peak of 84 bcm in 2011. While European LNG imports fell down last year to 43 bcma, Turkish LNG imports grew to almost 8 bcma.

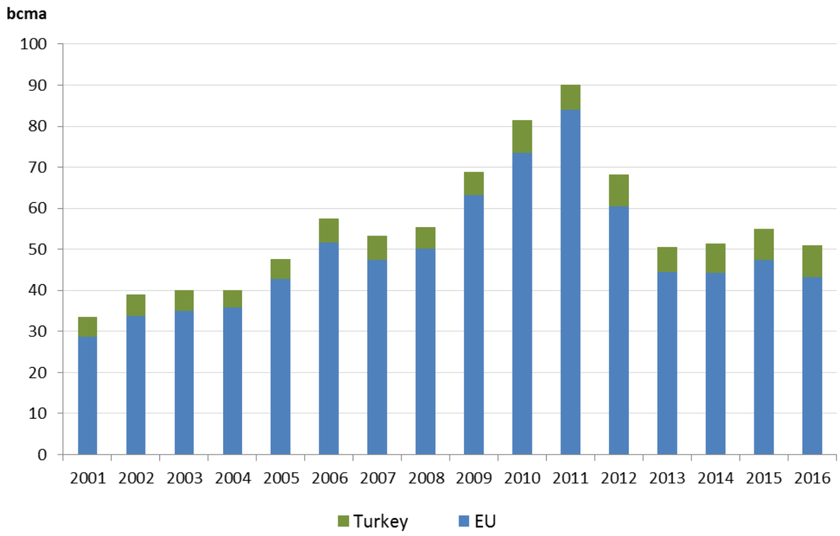

Figure 35: Evolution of LNG imports in Europe-Eurasia. 2001-2016 (source BP statistical reports 2002-2017)

In 2016, the EU imported LNG from more than 10 different origins around the world. The number of different origins supplying LNG to the EU has remained between 7 and 12 during the last decade. With new increasing number of LNG liquefaction plants located all around the world and the decreasing EU domestic production, higher LNG volumes will be available to arrive in Europe in the upcoming years, contributing further to increasing diversification, supply competition and security of supply.

1.4.2.10. Other potential sources

Other potential sources of gas supply for the future have been investigated but not included in the report due to their high uncertainty and that there are currently no facilities to export this gas to Europe and no Final Investment Decision has been taken yet in any foreseen project. On the other hand, ENTSOG's investigations found out that Israel has the potential to export abroad to its neighbouring countries in the near future.

1.4.3. Demand

Introduction

This chapter provides the methodology and processes used to collect and develop the total gas demand for the scenarios to be used for TYNDP 2018. Total gas demand is made up of Final Gas Demand (defined as Residential & Commercial, Industrial and Transport sectors) and Gas Demand for Power Generation.

Based on decades of experience, gas TSOs have developed expertise in terms of gas demand. ENTSOG builds on this expertise by collecting at national level data from its TSO end-user demand data for the different story lines. This is the source of data for final gas demand within the TYNDP 2018 scenarios.

Gas demand for power generation is the result of the ENTSO-E modelling process, with a conversion from the electricity generation required by the optimal dispatch output into the fuel input required for this.

Bottom Up Data Collection

Demand data is submitted from TSOs in accordance with the demand scenario storylines, parameters and prices, using national expertise to provide country-level specifics (which are provided as part of this annex). A data collection questionnaire is provided, which covers all scenarios as well as any gas demand as a result of newly gasified areas enabled by future projects where applicable, which is classified as gasification demand.

Values are provided for all years up to 2040 for the yearly average volume, seasonal variation as well as the high demand cases of the peak day (1-day Design Case, DC) and the 2-week high demand case (14-day Uniform Risk, 2W) average daily demand. Seasonal and high demand situations are covered in more detail in section 1.4.5.

Years	Name	Type	Demand derived from
2020, 2025	Best Estimate (inc gas before coal and coal before gas variations)	Bottom up (Final) / Top down (Power)	TSO Data collection ENTSO-E Power input
2020, 2030, 2035, 2040	Global Climate Action Sustainable Transition Distributed Generation	Bottom up (Final) / Top down (Power)	TSO Data collection ENTSO-E Power input
2030	EUCO Scenario	Top down	EC EUCO30 Data – Final Demand ENTSO-E Power input

Table 24: ENTSOG scenario types

Scenarios

In instances where TSO input focused on one (or two) specific scenarios, data was complemented in consultation with the relevant TSO in order to provide a complete dataset. In the instance where only one scenario was provided, this was used as the 'Sustainable Transition' scenario, with the Distributed Generation and Global Climate Action scenarios generated from the 'Green Revolution' data from TYNDP 2017. Although driven by different factors, this typically saw a reducing final gas demand which would likely result from the increase in electric or hybrid heat pumps and pathways for electric and gas vehicles as considered in these scenarios' storylines.

If no 'Best Estimate' data was provided, then this was substituted with data from 'Sustainable Transition' up to 2025. This was possible as information for all scenarios was collected across the time horizon, with Sustainable Transition representing the storyline with the least change from current trends.
More details on how the national methodology to derive demand data has been can be found as part of the Gas Country Specifics included in the appendix section 1.4.6.

Final Demand – Sectoral

TSOs were asked to provide a sectoral split of gas demand. For countries where this was not provided by the TSO, this has been determined through the use of the sectoral demand methodology. This takes publicly available data sources of historic demand and applies trends based on the storyline parameters for Residential & Commercial, Industrial and Transport sectors.

Industrial demand is viewed as stable in both Sustainable Transition and Global Climate Action, with energy efficiency offset by increases in output. Distributed Generation sees a reduction of industrial demand, with a linear progression of 1% p.a. applied.

CCS for industrial gas demand is defined as low growth for both Sustainable Transition and Global Climate Action, and considered not significant for Distributed Generation. It is determined that heavy industry with high load hours may make CCS commercially viable in these scenarios, whereas in power generation this would likely not be the case. Data and demonstration projects currently remain limited, so it is assumed that there will be no CCS applied to industrial demand in 2030 for all scenarios. The EC Roadmap to 2050[22] has been referenced stating that by 2030 nearly 10% of all emissions could be captured by CCS, which increases to over 40% by 2040. Given the low to not significant potential described by the scenarios, but also noting the increased carbon prices, CCS has been applied to 20% of industrial gas demands in Sustainable Transition 2040 and Global Climate Action 2040 and 15% in Distributed Generation 2040.

Transport demand development was based on publicly available data from the NGVA (Natural Gas Vehicle Association), using historic NGV penetration in the EU28 from 2011 to 2016 and country level data on vehicles and filling stations[23]. Growth rates have varied between 3% and 10%, with an average of 5.5% over these years. Recent developments have seen greater market share increases in the heavy goods vehicle category but slower overall market increase.
Based on this data, Distributed Generation low growth was set at 2% p.a., Sustainable Transition high growth at 4.5% p.a. and Global Climate Action very high growth at 8% p.a. If no historic data for natural gas vehicle use is available for a country then development is considered at 0% regardless of the scenario growth level.

Residential & Commercial was calculated as the balancing factor for final demand after applying Transport and Industrial assumptions, with reductions varying on a country-level basis assumed to be driven by energy efficiency and introduction of heat pumps. In instances where increases were seen, this should be seen as related to fuel switching from more polluting energy sources.

Although the final demand development follows the expected trends at a EU28+ level, there are significant differences between the evolutions of demand at country level, reflective of current and future energy mixes. For more information on the assumptions behind the country level evolution of demand, please refer to the Gas Country Specifics included in the appendix section 1.4.6.

1.4.4. Gas demand for power generation

General information

Gas for power generation for all scenarios is the result of the ENTSO-E modelling results. During the data collection phase, gas and electricity TSOs worked together to discuss gas installed capacity on a country-level basis.

[22] http://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/2050-energy-strategy
[23] https://www.ngva.eu/downloads/NGVA_Europe_Statistical_Report-2017.pdf

Yearly gas demand for power generation averages are calculated from the average of all approved models across all climate years.

2-week and Peak data is derived from the highest 2-week gas generation and single day gas generation coming from the 1982 climate year and using a single model that was available across all scenarios.

Gas share of Other Non-RES (ONR)

As well as the specifically categorised gas fuelled installed capacity, Other Non-RES capacity also exists as part of the generation mix. Where available from e-TSO, gas share of Other Non-RES has been applied accordingly. Where no data was provided, nearly a 30% share of gas generation has been assumed unless justification could be provided by g-TSO for another factor, details in the table below.

Without the plant level detail available as with the other generation capacity, an assumed NCV efficiency rating of 50% has been applied.

ID	ONR Coal	ONR Gas	ONR Oil	ONR Capacity MW	Gas Share %
AT	42	1	0	984	0.02
BA	0	0	0	0	0.00
BE	0	100	0	1710	1.00
BG	0	1	0	1579	1.00
CH	0	100	0	987	1.00
CY	0	0	0	0	0.00
CZ	19	81	0	1505	0.81
DE	0	0	0	10321	0.00
DEkf	0	0	0	0	0.00
DKe	0	200	0	87	1.00
DKkf	0	0	0	0	0.00
DKw	0	200	0	325	1.00
EE	0	0	0	150	0.29
ES	0	0	0	8500	0.29
FI	0	100	0	450	1.00
FR	0	0	0	0	0.00
GB	0	1	0	11036	0.80
GR	0	0	0	0	0.00
HR	50	50	0	200	0.50
HU	0	100	0	355	1.00
IE	0	100	0	160	1.00
ITcn	0	0	0	520	0.29
ITcs	0	0	0	562	0.29
ITn	0	0	0	3253	0.29

ID	ONR Coal	ONR Gas	ONR Oil	ONR Capacity MW	Gas Share %
ITs	0	0	0	909	0.29
ITsar	0	0	0	693	0.29
ITsic	0	0	0	520	0.29
LT	0	0	0	227	0.29
LUb	0	0	0	0	0.00
LUf	0	0	0	0	0.00
LUg	0	100	0	90	0.00
LUv	0	0	0	0	0.00
LV	0	100	0	150	1.00
ME	0	0	0	0	0.00
MK	0	0	0	0	0.00
MT	0	100	50	148	0.60
NI	0	100	0	26	1.00
NL	0	170	0	3539	0.70
PL	75	21	4	7276	0.21
PT	0	100	0	1052	1.00
RO	0	0	0	0	0.00
RS	0	0	0	0	0.00
SE1	0	0	0	0	0.00
SE2	0	0	0	0	0.00
SE3	33	67	0	390	0.67
SE4	0	0	0	0	0.00
SI	0	0	0	159	0.00
SK	20	58	21	899	0.58

Table 25: Reported share of Other Non-RES technology between Coal, Gas and Oil plus total capacity. Calculated gas share used in conversion of electricity generation to gas consumption.

Electricity generation to gas consumption

The data outputs from the ENTSO-E modelling results are in the form of net generation. In order to convert to the require fuel input that will be used in the ENTSOG model, several factors need to be applied.

1. Conversion factor to gross generation. Takes into account plant own uses of energy[24]. Although these losses are likely to have been effectively reduced to improve profitability, some energy efficiency improvement is assumed over time.

Factor	2020 - 2025	2030	2040
Net to Gross Generation	3.0%	2.5%	2.0%

Table 26: Conversion factor for net to gross generation

2. Efficiency of power plants. This has been determined by the ENTSO-E dataset detailing standard efficiency per power plant classification.

Fuel	Type	Efficiency range in NCV terms %	Standard efficiency in NCV terms %
Gas	conventional old 1	25% - 38%	36%
	conventional old 2	39% - 42%	41%
	CCGT old 1	33% - 44%	40%
	CCGT old 2	45% - 52%	48%
	CCGT new	53% - 60%	58%
	CCGT CCS	43% - 52%	51%
	OCGT old	35% - 38%	35%
	OCGT new	39% - 44%	42%

Table 27: Gas power plant efficiency

3. Net Calorific Value (NCV) to Gross Calorific Value (GCV). Power plant efficiency is calculated on NCV, in order to bring gas demand for power generation in line with other data collected for the scenarios, this needs to be represented in GCV.

Factor	2020 - 2025	2030	2040
NCV to GCV	10%	10%	10%

Table 28: NCV to GCV conversion

[24] Assumptions based on Eurelectric 'Efficiency in Electricity Generation', July 2003

4. Country and zonal demand. Due to differences in balancing zones for electricity and gas, some data has been grouped and split accordingly.

<table>
<tr><th>ENTSO-E Zones</th><th>Grouped</th><th>ENTSOG Zones</th></tr>
<tr><td>DE</td><td rowspan="2">DE</td><td>DEn</td></tr>
<tr><td>DEkf</td><td>DEg</td></tr>
<tr><td>DKe</td><td rowspan="3">DK</td><td rowspan="3">DK</td></tr>
<tr><td>DKkf</td></tr>
<tr><td>DKw</td></tr>
<tr><td rowspan="3">FR</td><td rowspan="3">FR</td><td>FRn</td></tr>
<tr><td>FRs</td></tr>
<tr><td>FRt</td></tr>
<tr><td>GB</td><td rowspan="2">UK</td><td rowspan="2">UK</td></tr>
<tr><td>NI</td></tr>
<tr><td>ITcn</td><td rowspan="6">IT</td><td rowspan="6">IT</td></tr>
<tr><td>ITcs</td></tr>
<tr><td>ITn</td></tr>
<tr><td>ITs</td></tr>
<tr><td>ITsar</td></tr>
<tr><td>ITsic</td></tr>
<tr><td>LUb</td><td rowspan="4">LU</td><td rowspan="4">LU</td></tr>
<tr><td>LUf</td></tr>
<tr><td>LUg</td></tr>
<tr><td>LUv</td></tr>
<tr><td>SE1</td><td rowspan="4">SE</td><td rowspan="4">SE</td></tr>
<tr><td>SE2</td></tr>
<tr><td>SE3</td></tr>
<tr><td>SE4</td></tr>
</table>

Table 29: ENTSO-E/ENTSOG Balancing zones

Gas for power generation data was collected from all gas TSOs as well and is available as part of the Excel data tables. Gas TSO liaised with Electricity TSO regarding installed capacity for gas power plants, but the gas for power generation data was also used as a comparison of results from the ENTSO-E market modelling processes.

This data is also important in terms of the high demand situations against which the gas infrastructure is tested. Peak and 2-week high demand cases are part of TYNDP assessment, usually representing 1-in-20 or national design case situations driven by regulation. ENTSO-E models have been run against three climatic years which may not provide the demand levels required.

1.4.5. Seasonal and high demand situations

The day of highest consumption in the year is a key input of the network design process and represents one of the most stressful situations to be covered by the gas transmission system. The design and operation of a system is also challenged by the availability of supply sources during periods of high consumption.

Gas demand in Europe shows a strong seasonal pattern, with demand being substantially higher in the winter than in the summer. These variations are largely driven by temperature-related heat demands in the Residential and Commercial sectors. It is therefore critical to test gas infrastructure both on a volumetric and peak demand basis, and as a result both seasonal variation and high demand data is collected.

The following high demand situations are defined in the data collection:

- 2-week high demand case (2W, 14-day uniform risk): Maximum aggregation of gas demand reached over 14 consecutive days once every twenty years in each country to capture the influence of a long cold spell on supply and especially on storage. The 14 days high demand period takes place based on the modelled situation from the over-the-whole-year simulation and is modelled starting on 15 February (after day 106 of storage withdrawal period).
- 1-day Design Case (DC, Peak): Maximum level of gas demand used for the design of the network in each country to capture maximum transported energy and ensure consistency with national regulatory frameworks. The peak day takes place based on the modelled situation from the over-the-whole-year simulation and is modelled on 31 January (after day 91 of storage withdrawal period).

No seasonal or high demand data was available from the EUCO30 data provided, therefore ENTSOG has applied a ratio to derive this information from yearly average data. This ratio is based on the data provided by gas TSO for the Global Climate Action, seeing the variation from yearly average to 2-Week and Peak Day demand levels.

Power generation peak and 2-week data can be sourced from the ENTSO-E market model results, by looking at the highest generation over a single day and consecutive 14 days. This is available from three climatic years, but this may not cover the regulatory requirements for TYNDP assessment. As a result, ENTSOG has assessed gas TSO high demand power assumptions against the gas installed capacity in order to provide the necessary data for TYNDP assessment.
Where gas demand for power generation peak and 2-week provided by gas TSO exceeds the market model results, this demand has been accepted up to a limit of what can be generated by the installed capacity.
Where gas demand for power generation peak and 2-week provided by the market model results exceeds the gas TSO data, this demand has been reduced by 10%. This is designed to reflect the nature of gas demand behaviour, based on historic data, where typically when gas demand is high in final demand sectors, power generation will reduce due to prices.

1.4.6. Country Specifics

Based on decades of experience gas TSOs have developed expertise in terms of gas demand and indigenous production. ENTSOG builds on this expertise by collecting at national level data from its TSO end-user demand data for the different storylines, as well as indigenous production data – both for conventional and green gases.

The Country Specifics information provides insight into the methods and tools used to develop the data. It can also be where national level differences that exist from the EU level parameters set by the storylines can be highlighted.

1.4.6.1. AT (Austria)

Methodology

Gas Connect Austria and the tools used when delivering the supply and demand data have been the following: Main sources in this context are the data provided by our NRA E-Control Austria and the official Austrian natural gas statistics. The Austrian natural gas statistics contain market information but also cover the energy balance. The monthly natural gas balance is based on the first and second clearing for demand and supply. To this hourly data, the main balance items are added on a monthly basis. This includes e.g. physical imports and exports, production (extraction), injection into and the withdrawal from storage facilities, injection of biogas and own use for production, storage and transport. The natural gas statistics are therefore commodity balances based on physical flows (source: E-Control Austria).

Data is based on information published by E-Control Austria in the form of its most recent statistics. These reflect the energy efficiency and CO_2 targets and scenarios to the extent they are implemented and impacting the energy mix in Austria as well.

Sustainable Transition

Final demand provided by TSO.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

Distributed Generation, Global Climate Action

Final demand reflects TYNDP 2017 Green Revolution data.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

1.4.6.2. BA (Bosnia Herzegovina)

Sustainable Transition

Final demand provided by TSO. No further comments have been reported.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

Distributed Generation, Global Climate Action

Final demand reflects TYNDP 2017 Green Revolution data.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

1.4.6.3. BE (Belgium)

Methodology

General

The values for final demand and power generation are in line with the storyline of the three ENTSOG scenario's and are compatible with the Fluxys Belgium Network Development Plan demand scenarios covering the period 2017-2026.

Residential & Commercial

The projected values for the residential and commercial sector are based on a global study regarding the evolution of the residential average and peak gas demand in the different regions of Belgium.

Power generation

The major driver for change in the Belgian power generation sector, regardless of the scenario, is an important transition phase with the announced closure of all Belgian nuclear power plants. The first reactors are planned to close as of Q3 2022 and by the end of 2025 all of the 6 GW nuclear power plants are planned to be permanently closed.

Given that the power usage is expected to remain stable, these closures will have to be compensated through a combination of additional renewable power, additional imports of excess electricity production in the neighbouring countries and gas-fired power production. Renewables are known for their intermittent character. The availability of excess electricity production in the neighbouring countries is also highly uncertain given it is based on foreign policies putting more emphasis on intermittent renewables while at the same time closing down coal and nuclear-fired power plants. As a result gas-fired power generation is believed to continue to play an important role in the security of supply of Belgium. This has been reflected in the peak demand scenarios for power generation submitted by Fluxys Belgium.

Remark on ENTSO-E power generation methodology

In all TYNDP 2018 scenarios, market modelling results indicate that Belgium is a net importer on a yearly basis (which does not mean that it is the case all days of the year). However, this might be different when initial assumptions for Belgium and neighbouring countries would change; for a well interconnected country as Belgium, the values for generation mix and yearly balance are sensitive to fuel & emissions prices, efficiency of the generation fleet in the country and abroad, decisions on coal/nuclear phase out in CWE, hypothesis taken on must run units in the future (CHPs, for industrial processes, ...) , ...

Given uncertainties on this matter, country specific results provided in this report are to be interpreted with care, especially for countries where national energy transition policies have not yet been fully decided.

A more detailed overview of Belgian results for the electricity market including a large amount of sensitivities related to the efficiency of the thermal production fleet, fuel & emissions prices, interconnections, climate years, ... can be found in the latest study published by Elia in 2017 [http://www.elia.be/~/media/files/Elia/About-Elia/Studies/20171114_ELIA_4584_AdequacyScenario.pdf] covering the years 2030 and 2040 (with a more detailed modelling of CWE). This study provides (on top of detailed generation mix results) the need of new built gas units to remain adequate, calculated revenues for new built gas units, welfare indications and other economic parameters in each sensitivity. The different levels of yearly imports and exports are also given for each scenario in 2030 & 2040, mainly driven by the penetration of RES in Belgium and abroad, by the merit order (given that no more coal is installed in Belgium) and by the Belgian production fleet efficiency.

Sustainable Transition

Residential & Commercial

A small reduction of the residual and commercial demand is expected, especially for the annual volumes. The main key drivers are an increase in the efficiency of the installed base of heating appliances (mainly condensing boilers replacing non-condensing boilers), an uptake of hybrid heat pump (post-2020) which drives annual gas demand down but maintains the peak demand, and the application of building regulations for new built dwellings.

No changes have been taken into account after 2030 because of the limited visibility on longer term evolutions.
Industry
No significant evolution is expected based on the forecast of feedstock growth and the prospected evolution for heating applications.
No changes have been taken into account after 2030 because of the limited visibility on longer term evolutions.
Power plants
In the Sustainable Transition storyline, the nuclear power production in Belgium is expected to be mainly replaced by gas-fired power generation. Renewable power production mostly from wind and solar is expected to grow continuously, but will not be able to fully compensate the phase-out of the nuclear power production in Belgium.

Global Climate Action
Residential & Commercial
A significant decrease is expected especially due to a higher penetration of electrical heat pumps.
Industry
No significant difference is expected compared to the Sustainable Transition scenario storyline, with the electrification of heating application and a growing feedstock gas demand.
Power plants
Compared to the Sustainable Transition storyline, more emphasis is laid on the development of renewables and demand response management to compensate for the loss of nuclear power in Belgium. However gas-fired power generation continues to play a vital role to ensure the security of supply in Belgium, albeit with reducing running hours due to the increase in renewables.

Distributed Generation
Residential & Commercial
A decrease is expected due to a higher utilisation of hybrid (and electrical) heat pumps. On the other hand, almost no effect is expected on peak values with gas consumption needed for the hybrid heat pumps at low temperatures. An accelerated cost reduction in fuel cells and micro CHPs could also help to slow the rate of reduction in gas demand compared to the Global Climate Action scenario storyline.
Industry
A small decrease is expected compared to the Sustainable Transition scenario due to an increased electrification of process heating.
Power plants
Emphasis is laid on renewables, demand response and local power production in the Distributed Generation storyline. Gas-fired power generation capacity remains important for security of supply, but running hours will reduce over time due to increasing renewables and competition from demand response.

1.4.6.4. BG (Bulgaria)

Methodology
Bulgartransgaz EAD final demand scenario has been developed on the basis of a macroeconomic model showing the dependence of gas consumption in the country on the main macroeconomic indicators and a comparative analysis of the gas market in both the EU and Bulgaria, and the expected increased consumption, as a result of the joining of new users and expanding the production capacities of the existing ones.
The relationship between the final and primary energy consumption (FEC and PEC) and the GDP growth for past periods have been analysed as well.
The main assumptions made based on an analysis of the past ten-year period, a comparative EU gas market analysis and the objectives of the Energy Strategy of Bulgaria are as follows:

- *sustainable economic growth of GDP – between 2 and 3% annually*
- *FEC/PEC ratio reaches up to and above 60% in 2024*
- *the share of natural gas in PEC in 2025 reaches 19%, compared to 14% in 2015.*

Demand scenario is consistent with Bulgartransgaz's Ten Year Network Development Plan 2017-2026[25] *published in April 2017.*

Sustainable Transition

Bulgartransgaz EAD submitted inputs for the Sustainable Transition Scenario. Only one base scenario is developed in Bulgaria at national level. It resembles Sustainable Transition and it is characterised with a demand increase.

<u>Power generation</u>

Demand for power generation data is both for heat and electricity generation. The forecast is based on the same assumptions as the final demand.

The primary gas consumption in Bulgaria includes chiefly combined heat and electricity generation (thermal power stations, plants and co-generation in some industrial companies) thus it is therefore impossible to make a clear distinction between the gas used exclusively for power generation.

<u>Production</u>

In the following two years the domestic production is expected to remain at the levels of about 75–80 mcm as a result of the partial depletion of the existing fields in the country.

The forecast for domestic production growth after 2019 is based on the intensive study works of the local natural gas deposits and granted concessions for development of the deposits on the territory of the country both onshore and in the Black Sea shelf.

Production data is consistent with Bulgartransgaz's Ten Year Network Development Plan 2017-2026 published in April 2017.

Distributed Generation, Global Climate Action

Final demand reflects TYNDP 2017 Green Revolution data.

Sectoral split calculated using sectoral data methodology.

Gas demand for power generation calculated from ENTSO-E modelling results.

1.4.6.5. CH (Switzerland)

Methodology

Sectoral split calculated using sectoral data methodology.

Gas demand for power generation calculated from ENTSO-E modelling results.

Global Climate Action

The final gas demand in Switzerland is mainly driven by temperature since a big part of the demand (41%) is for heating purposes in the residential sector (source: "Gas in Zahlen 2016" by VSG the Swiss Gas Association). Since the temperature of next year cannot be forecasted the best estimate for the demand in the actual year is the demand of the previous year.

The Global Climate Action scenario assumes a reduction of gas demand in the residential sector since it assumes high growth of electric and hybrid heat pumps and of energy efficiency. The scenario foresees also high growth of the demand for gas vehicles.

The residential sector is the main source for demand in Switzerland, a reduction of that demand would not be compensated by the growth in the mobility/transport sector, equalling a slight reduction of the total demand under this scenario – this a TSO estimation since there is no study of an independent or public institution which forecasted the future gas demand under the conditions of the ENTSOG-scenarios. There is a study by the Swiss Federal Office of Energy SFOE "Die Energieperspektiven für die Schweiz bis 2050" but the scenarios are defined differently. However, according to that study the natural gas demand is decreasing in all chosen scenarios which are called "weiter wie bisher" (further with the same energy political measures which are in place now), "neue

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[25] https://bulgartransgaz.bg/files/useruploads/files/amd/tyndp%202017/TYNDP_2017-V.63.F.en_1.pdf
Data provided for all scenarios.

Energiepolitik" (with political measures which are internationally coordinated and with the goal of a 20% reduction of CO_2-emissions), and "politische Massnahmen" (with even more tightened political measures as more encouragement in energy efficiency in buidings etc.).

Sustainable Transition

The Sustainable Transition scenario assumes a slight reduction of gas demand in the residential sector since it assumes moderate growth of electric and hybrid heat pumps and of energy efficiency. The scenario foresees also a very high growth of the demand for gas vehicles.

In this scenario the reduction of the demand in the residential sector could be compensated by the very high growth in the mobility/transport sector.

Distributed Generation

The Distributed Generation scenario assumes a reduction of gas demand in the residential sector since it assumes a very high growth of electric and hybrid heat pumps and of energy efficiency. The scenario foresees only a low growth of the demand for gas vehicles. Furthermore, the gas demand in the industry sector is assumed to decrease (which is not the case in the other scenarios).

In this scenario the reduction of the total demand is even higher than in the Global Climate Action scenario.

1.4.6.6. *CY (Cyprus)*

Methodology

No data for Cyprus was submitted during the data collection. Data reflects TYNDP 2017 information.
No further comments have been reported. Gas demand relates to gasification.

1.4.6.7. *CZ (Czech Republic)*

Methodology

The TSO submitted the inputs for the different scenarios.
Demand is based on predictions from the Czech electricity and gas market operator (OTE, a.s.). The predictions are updated every year in November and contain three scenarios, which are similar to TYNDP 2018 scenarios below.

Global Climate Action

<u>Final demand</u>
Global Climate Action scenario is similar to Central scenario from the Czech electricity and gas market operator (OTE, a.s.).
<u>Residential & Commercial</u>
Demand distribution in calculated scenarios is similar to ENTSOG scenarios.
<u>Industrial</u>
Demand distribution in calculated scenarios is similar to ENTSOG scenarios.
<u>Transport</u>
Is similar to CNG/LNG consumption prediction from Czech electricity and gas market operator (OTE, a.s.).
<u>Non-network</u>
Not included in our calculations.
<u>Power generation</u>
The forecast is based on real connection requests for the power plants and on predictions from the Czech electricity and gas market operator (OTE, a.s.).
<u>Production</u>
Production prediction is based on sources assumptions.

Sustainable Transition

<u>Final demand</u>
Sustainable Transition scenario is similar to Conceptual scenario from the Czech electricity and gas market operator (OTE, a.s.).
<u>Residential & Commercial</u>
Demand distribution in calculated scenarios is similar to ENTSOG scenarios.
<u>Industrial</u>
Demand distribution in calculated scenarios is similar to ENTSOG scenarios.
<u>Transport</u>
Is similar to CNG/LNG consumption prediction from Czech electricity and gas market operator (OTE, a.s.).
<u>Non-network</u>
Not included in our calculations.
<u>Power generation</u>
The forecast is based on real connection requests for the power plants and on predictions from the Czech electricity and gas market operator (OTE, a.s.).
<u>Production</u>
Production prediction is based on sources assumptions.

Distributed Generation

<u>Final demand</u>

Distributed generation scenario is similar to Decentral scenario from the Czech electricity and gas market operator (OTE, a.s.).

Residential & Commercial

Demand distribution in calculated scenarios is similar to ENTSOG scenarios.

Industrial

Demand distribution in calculated scenarios is similar to ENTSOG scenarios.

Transport

Is similar to CNG/LNG consumption prediction from Czech electricity and gas market operator (OTE, a.s.).

Non-network

Not included in our calculations.

Power generation

The forecast is based on real connection requests for the power plants and on predictions from the Czech electricity and gas market operator (OTE, a.s.).

Production

Production prediction is based on sources assumptions.

1.4.6.8. DE (Germany)

Final demand

The final energy demand scenarios for the years 2017 to 2025 are based on the scenario framework of the German NDP 2016.

The final energy demand scenarios for the years 2026 to 2035 are based on the target scenario ("Zielszenario") of the public study "Energy Reference Forecast" for the German Federal Ministry of Economics and Technology of June 2014.

The peak day values for the years 2017 to 2025 are derived from the yearly values by applying load factors for the different consumption sectors as determined in a study of the German TSOs and DSOs and published in the German NDP 2015. The peak day values for the years 2026 to 2035 are kept constant at the level of the year 2025.

The 2-week cold spell values for the final gas demand are determined with the help of a temperature-based linear interpolation between the peak day and yearly values.

Power generation

The forecast of the gas consumption in the power sector is based on data provided by ENTSO-E for the different scenarios, namely the annual power generation and the installed capacities of gas-fired power plants, split by type of power plant.

The gas demand for power generation is calculated with the help of an average degree of efficiency for every type of power plant (provided by ENTSOG) including an additional factor for adding the gas demand for operating power of the respective power plant. Since ENTSO-E data are only available for selected years the gas consumption for the intermediate years have been derived by means of interpolation. The average demand then has been calculated by dividing the annual gas demand by 365.

The peak demand has been derived by using the installed electric capacities for every type of power plant and typical load factors of German gas-fired power plants based on hourly TSO data. The gas demand is then calculated by using the factors for average efficiency and own consumption as described above. Since ENTSO-E data are only available for selected years the installed capacities for the intermediate years have been derived by means of interpolation.

The two-week gas cold spell demand has been derived by using a linear regression between peak day and average day and the respective temperature of the two-week case.

For each scenario, the starting values for the year 2018 are derived from data collected by the German TSO for the upcoming national Network Development Plan.

Global Climate Action

The development of the final demand is similar to the development in the scenario Distributed Generation except for the sectors industry and transportation. In line with the description of this scenario, the industry demand for the years 2027 to 2035 is assumed as staying on the level of the industry demand of the year 2026. In line with the description of this scenario, a high growth of the gas demand for transportation is assumed.
The development of power generation was derived according to the methodology described in the methodology section above.

Sustainable Transition
The development of final demand and power generation was derived according to the methodology described in the methodology section above. In line with the description of this scenario, a very high growth of the gas demand for transportation is assumed.

Distributed Generation
Compared to the scenario Sustainable Transition, a further reduction is assumed so that final demand for the years 2025 to 2040 is approximately 90% of the respective values for the scenario Sustainable Transition. In line with the description of this scenario, a low growth of the gas demand for transportation is assumed.
The development of power generation was derived according to the methodology described in the methodology section above.

1.4.6.9. *DK (Denmark)*

Methodology
The data provided for Denmark for the three TYNDP scenarios is to match the ENTSO scenarios to similar scenarios developed by Energinet during 2016. The scenarios are presented at the following webpage:
https://www.energinet.dk/Analyse-og-Forskning/Analyser/RS-Analyse-Energiscenarier-for-2030

Direct link to English summary:
https://www.energinet.dk/-/media/Energinet/Analyser-og-Forskning-RMS/Dokumenter/Analyser/Energy-Scenarios-for-2030-UK-Version.PDF

The Energinet scenarios from 2016 are based on ENTSO-E TYNDP16 visions. This means that the ENTSO-E visions have been supplemented with information about developments outside the electricity sector. Mainly gas, transport, heating and industry in Denmark only. Additionally any new trends and developments have been captured in the new scenarios.

Generally Energinet is not a strong supporter of bottom-up scenarios. The risk of having inconsistent scenarios is considered too large. Specifically for a small country with strong electricity and gas interconnectors to neighbouring countries the development in the country is very dependent on developments in other regions in Europe.

Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

Global Climate Action
Global Climate Action – has many similarities with Green Europe and is used as such.
Green Europe describes a state with a strong joint RES development in Europe. This means reduction of gas for heating purpose (replaced with heat pumps), a strong development of RE electricity production (especially off-shore wind).
For the gas system there are large amounts of biomethane and even growing use of power-to-gas. Gas is used for transportation in ships and trucks where battery technology has too little capacity to be useful. Overall the gas demand is declining.

Sustainable Transition

Sustainable Transition – is very much in line with Energinet's best guess assumptions called "Energinet's analysis assumptions". The data collection for TYNDP 18 is based on the 2016 numbers: https://www.energinet.dk/Analyse-og-Forskning/Analyseforudsaetninger/Analyseforudsaetninger-2016

The current political climate favours very much an economically sustainable development towards the 2030 targets.

Distributed Generation

Distributed Generation – has many similarities with the "Green Nations" scenario. Development of solar and batteries are very strong in the scenario and the scenario is optimised to utilise local resources rather than international.

1.4.6.10. *EE (Estonia)*

Global Climate Action

<u>Final demand</u>

The demand data is partly based on a study and partly based on TSO's own assumptions. The study was about long-term gas consumption forecast in Estonia and it was conducted by consultants from university. The main decrease of demand arises from the switch from gaseous fuels to other alternative fuels in the heating sector.

<u>Power generation</u>

No new gas-fired power stations are foreseen for the future.

Sustainable Transition

<u>Final demand</u>

The demand data is partly based on a study and partly based on TSO's own assumptions. The study was about long-term gas consumption forecast in Estonia and it was conducted by consultants from university. In this scenario it is assumed that the switch to other alternative fuels in the heating sector is not as big as in the other two scenarios.

<u>Power generation</u>

No new gas-fired power stations are foreseen for the future.

Distributed Generation

<u>Final demand</u>

The demand data is partly based on a study and partly based on TSO's own assumptions. The study was about long-term gas consumption forecast in Estonia and it was conducted by consultants from university. The main decrease of demand arises from the switch from gaseous fuels to other alternative fuels in the heating sector.

<u>Power generation</u>

No new gas-fired power stations are foreseen for the future.

1.4.6.11. *ES (Spain)*

Global Climate Action

<u>Final demand</u>

<u>Residential & Commercial</u>: It has been considered a slightly lower growth of new residential customers than the current trend (+80.000 customers per year). The R&C gas demand decreases due to the efficiency effect (aligned with the PRIMES scenario).

<u>Industrial</u>: The efficiency effect is similar than in the EUCO 2030 scenario. An increasing GDP and new industrial customers induce a growth of the Industrial consumption since these effects are greater than the efficiency.

<u>Non-network</u>: Stable consumption.

Power generation
Growth of wind and solar installed power and dismantling of the coal-fired power accordingly with the EUCO 2030 scenario. This growth of renewable generation induces increasing energy exports. The increasing coal and CO_2 prices from the WEO, the increasing energy exports and the dismantling of the coal-fired power mean a growth of power generation with gas.

Sustainable Transition
Final demand
Residential & Commercial: It has been considered a growth of new residential customers accordingly with the current tendency (+100.000 customers per year). Although gas consumption per customer decreases because of the efficiency effect, the growth in the number of customers and the increasing GDP promote an increase in gas demand.

Industrial: The effect of the efficiency improvements is lower than in the EUCO 2030 scenario. An increasing GDP and new industrial customers lead to a growth in the Industrial consumption since these effects are greater than the efficiency.

Non-network: Stable consumption.

Power generation
Growth of wind and solar installed power and dismantling of the coal-fired generation is slower than in the EUCO 2030 scenario. This growth of renewable generation leads to increasing energy exports and increasing GDP promotes an increasing power demand. The result is a growth of the power generation with gas.

Distributed Generation
Final demand
Residential & Commercial: It has been considered a lower growth of new residential customers than the current trend (+60.000 customers per year). The R&C gas demand decreases due to the efficiency effect (aligned with the PRIMES scenario).

Industrial: The efficiency effect is similar to that in the EUCO 2030 scenario. An increasing GDP and new industrial customers lead to a growth of the Industrial consumption since these effects are greater than the efficiency.

Non-network: Stable consumption.

Power generation
Growth of wind and solar installed power accordingly with the EUCO 2030 scenario. Despite the dismantling of the coal-fired generation (according to the EUCO 2030 scenario) and the increasing energy exports, the power generation with gas decreases due to the emergence of distributed generation.

1.4.6.12. *FI (Finland)*

Methodology
Final demand provided by TSO. No further comments have been reported.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

1.4.6.13. *FR (France)*

Methodology

Scenarios for final demand are consistent with the scenarios developed jointly by GRTgaz, TIGF, GRDF and SPEGNN in the first Multiannual Forward Estimate published in November 2016. It is consistent with GRTgaz's Ten Year Network Development Plan 2016-2025, also published in November 2016.

Global Climate Action

Final demand

Final demand for Global Climate Action is based on Scenario C from national multiannual forward estimate 2016. This scenario follows a low trend for gas consumption. It assumes the impact of new environmental regulation leading to a decline in gas consumption. Gas for transport sees a moderate growth.

The target of a 30% reduction in the consumption of fossil fuel applies to gas, notwithstanding its performance compared to oil or coal.

Power generation

Scenarios for final demand are consistent with the scenarios developed jointly by GRTgaz, TIGF, GRDF and SPEGNN in the first Multiannual Forward Estimate[26] published in November 2016. It is consistent with GRTgaz's Ten Year Network Development Plan 2016-2025 [27], also published in November 2016.

Production

The growth of local biomethane production is high. The national Law on energy transition targets increasing the share of renewable energy to 10% of gas consumption by 2030. This scenario assumes a pro-active development of up to 30 TWh of biomethane injected into the gas grid in 2030.

Sustainable Transition

Final demand

Final demand for Sustainable Transition is based on Scenario B from national multiannual forward estimate 2016. This scenario follows a high trend for gas consumption. It assumes a growing use of gas in the industry and in the residential sector, used as a substitute for fuels whose environmental and economic impact is less favourable. The development of gas for transport is being advocated proactively to reach 1 million vehicles.

This scenario is in line with national objectives set for 2023, and a little behind regarding objectives for 2030.

Power generation

Demand for power generation is consistent with the data submitted by RTE for Sustainable Transition. The installed capacity for gas-fired power plant remains stable at 6.7 GW (including Bouchain and Landivisiau) while the duration of use is steadily growing.

Production

The growth of local biomethane production is high. The national Law on energy transition targets increasing the share of renewable energy to 10% of gas consumption by 2030. This scenario assumes a pro-active development of up to 30 TWh of biomethane injected into the gas grid in 2030.

Distributed Generation

Final demand

Final demand for Distributed Generation is based on Scenario A from national multiannual forward estimate 2016. This scenario follows a main trend. It takes into account the current regulation and tolerable efforts from households and industry both in terms of energy savings and energy efficiency. The development of gas for transport follows a high growth.

Power generation

[26] http://www.grtgaz.com/fileadmin/plaquettes/fr/2016/Perspectives-gaz-naturel-et-renouvelable.pdf

[27] http://www.grtgaz.com/fileadmin/plaquettes/en/2016/Plan_decennal_2016-2025-EN.pdf

Gas demand for power generation is significantly reduced in this scenario. Profitability for gas-fired power plant is low and gas demand for cogeneration is stagnating. The installed capacity for gas-fired power plant remains stable but the duration of use is low.

Production

The growth of local biomethane production is high. The national Law on energy transition targets increasing the share of renewable energy to 10% of gas consumption by 2030. This scenario assumes a pro-active development up to 30 TWh of biomethane injected into the gas grid in 2030.

1.4.6.14. GR (Greece)

Sustainable Transition

Final demand provided by TSO. No further comments have been reported.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

Distributed Generation, Global Climate Action

Final demand reflects TYNDP 2017 Green Revolution data.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

1.4.6.15. HR (Croatia)

Methodology

The data related to the future Croatian gas consumption are consistent with PLINACRO's Ten Year Network Development Plan 2016-2026. The demand predictions were carried out by direct survey of future expected gas needs from PLINACRO's customers: gas distribution companies, direct industrial customers, petrochemical industry and electricity production companies. It is presumed that surveyed gas consumption should be in line with the Croatian energy policies and consumption trends, which by their main characteristics fit to the Sustainable Transition scenario.

It is estimated that the gas consumption in the gas distribution sector and for direct industrial customers will decrease in the Global Climate Action scenario, compared to the Sustainable Development scenario, due to the introduction of new renewable technologies (related to the reduction of CO_2) and other actions which will be undertaken related to the mitigation of climate change. In the Distributed Generation scenario, it is expected that the gas consumption in the gas distribution sector and for direct industrial customers will increase, when compared to the Sustainable Transition scenario, with more gas used in the local, small electricity production units.

The new renewable technologies (related to the reduction of CO_2) and other actions which will be undertaken related to the mitigation of climate change from the Global Climate Action scenario, and more locally, in small electricity production units produced electricity from Distributed Generation scenario results will decrease of gas use in classical power generation units which is represented with the reduction of gas consumption for power generation in both Global Climate Action and Distributed Generation.

1.4.6.16. HU (Hungary)

Methodology

FGSZ Ltd. final demand has been developed on basis the Hungarian Distribution System Operators and consumers directly connected to the natural gas transmission system and Network Users forecast data and experience of the TSO's analysis of the last six years' consumption especially in case of temperature-dependent exit points.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

Global Climate Action

The TSO estimates the Final Demand Average decrease more than 2% per year and the Demand Average Power Generation increase less than 2% per year.

Sustainable Transition

The TSO estimates the Final Demand Average decrease less than 1% per year and the Demand Average Power Generation increase more than 2% per year.

Distributed Generation

The TSO estimates the Final Demand Average decrease ~1.5% per year and the Demand Average Power Generation increase less than 1.3% per year.

1.4.6.17. *IE (Ireland)*

Methodology

The demand forecasts presented in the document are based on the median demand scenario from the Gas Networks Ireland Network Development Plan 2016.

In the power generation sector gas demand forecasts are developed based on the key assumptions from the Eirgrid Generation Capacity Statement 2016-2025 in terms of electricity demand and generation capacity.

In the residential sector Gas Networks Ireland's own new connection forecasts have been developed. These forecasts take account of observed fuel switching in mature housing and new housing forecasts, based on enquiries from developers and observed trends in new housing planning applications.

In the Industrial & Commercial sectors gas demand forecasts are based on the observed relationship between demand growth and GDP growth, with an additional incremental allowance for new connections.

Energy efficiency savings impacting on Industrial & Commercial and residential gas demands are also allowed for, based on the Irish Government's National Energy Efficiency Action Plan.

In the transport sector Gas Networks Ireland is undertaking a European-funded project called the Causeway Study in order to encourage the uptake of CNG by commercial fleet operators. This study aims to examine the impact of increased levels of fast fill CNG stations on the operation of the transmission and distribution gas networks in the Republic of Ireland (ROI). A pilot network of 14 CNG units along the TEN-T (Trans European Transport Network) Core Road Network will be built to assess the impact on the gas network. Activities will encompass developing an understanding of the operation and planning of the network, CNG equipment, CNG user demand patterns and behaviours, and the injection of renewable gas into the gas transmission system.

Sustainable Transition

Final demand provided by TSO.

Sectoral split calculated using sectoral data methodology.

Gas demand for power generation calculated from ENTSO-E modelling results.

Distributed Generation, Global Climate Action

Final demand reflects TYNDP 2017 Green Revolution data.

Sectoral split calculated using sectoral data methodology.

Gas demand for power generation calculated from ENTSO-E modelling results.

1.4.6.18. *IT (Italy)*

Methodology

All data are the result of internal elaborations.

The scenarios are built starting from macroeconomic variables (such as GDP, Industrial Production Index, inflection, energy prices, CO_2 prices) and constraints (such as environmental policies, EU and national targets, scenario guidelines). These inputs are fed into a model which builds a complete primary energy mix (solids, natural gas, oil, renewables, electricity) for each sector. The model also builds the power balance to assess the electricity generation mix. The overall gas demand is obtained as the sum of the sectorial demands.

Conventional and non-conventional gas productions are obtained through an elaboration of historical data and expected future developments.

The developed scenarios are consistent with the ones built for the ten-year development plan of SNAM Rete Gas.

Global Climate Action

Final demand

Natural gas demand in R&C and industrial sectors decreases, mainly because of improvements in energy efficiency. Strong penetration of natural gas in the transport sector.

Residential & Commercial

In the Global Climate Action scenario, a high penetration of electric heat pumps for heating and cooling purposes in the residential sector pushes the electricity demand at the expense of the gas demand.

In the 2017-2040 period, the demand decreases by 11.6 Bcm, reaching 17.2 Bcm in 2040.

Industrial

Demand in industrial sector decreases by -0.9% in 2017-2040.

The impact of energy efficiency improvements is limited since natural gas consumption is already quite low. In the 2017-2040 period, the demand decreases by 3.3 Bcm, reaching 14.3 Bcm in 2040.

Transport

CNG penetration suffers from a higher share of electric vehicles, while biomethane penetration is in line with Sustainable Transition scenario, contributing to reach the renewable share target in fuels.

Overall gas consumption in transport increases by 7.3 Bcm, reaching 8.4 Bcm in 2040.

Non-network

Use of LNG in heavy transport and bunkering grow significantly over the period by 4.2 Bcm (20.6% yearly), reaching 4.3 Bcm in 2040.

Power generation

After 2020, high renewables penetration lowers the demand for fossil fuels. In the long term, gas demand for power generation is slightly higher than in the ST scenario, because of a complete switch from coal to gas driven by a CO_2 price reaching 50 €/t (in particular after 2034). 10 Bcm of biomethane in 2040. Italy halves electricity imports over the period, mainly because of French nuclear phase out, in line with the Transition énergétique. Imports decrease from 40.2 TWh in 2017 to 19.8 TWh in 2040. Gas demand increases by 8.5 Bcm in 2017-2040, reaching 30 Bcm.

Production

Conventional production decreases sharply in the 2017-2040 period by 4.3 Bcm (-4.7% yearly), reaching 2.1 Bcm in 2040. On the other hand, biomethane production increases by 29.9% yearly reaching 12.1 Bcm in 2040 (from almost zero in 2017).

Sustainable Transition

Final demand

Natural gas demand in R&C and industrial sectors decreases, mainly because of improvements in energy efficiency. Strong penetration of natural gas in the transport sector.

Residential & Commercial

Gas demand in R&C sector decreases by -1,1% in 2017-2040, driven mainly by energy efficiency improvements.

In the 2017-2040 period, the demand decreases by 6.7 Bcm, reaching 22.1 Bcm in 2040.

Industrial

Demand in industrial sector decreases by -0.9% in 2017-2040.

The impact of energy efficiency improvements is limited since natural gas consumption is already quite low. In the 2017-2040 period, the demand decreases by 3.3 Bcm, reaching 14.3 Bcm in 2040.

Transport

Highest growth in CNG consumption for road transport because of high financial support for the usage of this fuel in private cars and commercial car fleets. Moderate penetration of electricity in road transport. Natural gas consumption increases by 9.9 Bcm in 2017-2040, reaching 11 Bcm in 2040.

Non-network

Use of LNG in heavy transport and bunkering grow significantly over the period by 4,2 Bcm (20,6% yearly), reaching 4,3 Bcm in 2040.

Non-network
Use of LNG in heavy transport and bunkering grow significantly over the period by 4Power generation
A high coal price causes the low efficiency (< 32.5%) coal plants to shut down, in favour of the more efficient gas plants. Natural gas reaches 29 Bcm in 2040 (+7.5 Bcm with respect to 2017), of which 10 Bcm is biomethane, playing an important role as non-intermittent RES.
Production
Conventional production decreases sharply in the 2017-2040 period by 4.3 Bcm (-4.7% yearly), reaching 2.1 Bcm in 2040. On the other hand, biomethane production increases by 29.9% yearly, reaching 12.1 Bcm in 2040 (from almost zero in 2017).

Distributed Generation
Final demand
Natural gas demand in R&C and industrial sectors decreases, mainly because of improvements in energy efficiency and consistent growth of distributed generation. Strong penetration of natural gas in the transport sector.
Residential & Commercial
A high penetration of electric heat pumps for heating and cooling purposes in the residential sector pushes the electricity demand at the expense of the gas demand.
In the 2017-2040 period, the demand decreases by 11.6 Bcm, reaching 17.2 Bcm in 2040.
Industrial
Demand in industrial sector decreases by -0.9% in 2017-2040.
The impact of energy efficiency improvements is limited since natural gas consumption is already quite low. In the 2017-2040 period, the demand decreases by 3.3 Bcm, reaching 14.3 Bcm in 2040.
Transport
Biomethane penetration is in line with ST and GCA scenarios. Electric vehicles penetration is slightly higher than in the GCA scenario, reducing the share of fossil fuels. Overall gas consumption in transport increases by 5.2 Bcm in 2017-2040, reaching 6,3 Bcm in 2040.
Non-network
Use of LNG in heavy transport and bunkering grow significantly over the period by 4,2 Bcm (20,6% yearly), reaching 4,3 Bcm in 2040.
Power generation
After 2020, PV penetration is even higher than in the GCA scenario, causing the gas demand for power to further decrease. Same assumption of complete coal-to-gas switch after 2034. Same penetration of biomethane as in ST and GCA scenarios. Natural gas reaches 24.6 Bcm in 2040 (+3.1 Bcm with respect to 2017), of which 10 Bcm of biomethane.
Production
Conventional production decreases sharply in the 2017-2040 period by 4.3 Bcm (-4.7% yearly), reaching 2.1 Bcm in 2040. On the other hand, biomethane production increases by 29.9% yearly, reaching 12.1 Bcm in 2040 (from almost zero in 2017).

1.4.6.19. LT (Lithuania)

Sustainable Transition
Final demand
The input data only for the Sustainable Transition scenario has been provided. The forecast for the Final demand is based on the historical data on gas consumption in Lithuania, system users' survey results and overall energy sector development perspectives in Lithuania.
Residential & Commercial
Industrial
The forecast for the industrial sector is based on the historical data on gas consumption in Lithuania, system users' survey results and overall energy sector development perspectives in Lithuania.
Transport

The forecast for the transport sector is based on the historical data received from the Statistics Department of Lithuania, system users' survey results and overall energy sector development perspectives in Lithuania.
Non-network
There is no non-network gas consumption in Lithuania.
Power generation
The input data for power generation is based on the historical data on gas consumption for power generation in Lithuania, system users' survey results to split the shares of gas used for electricity generation and heating in power generation facilities and overall energy sector development perspectives in Lithuania.
Production
There is no gas production in Lithuania.

Distributed Generation, Global Climate Action
Final demand reflects TYNDP 2017 Green Revolution data.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

1.4.6.20. *LU (Luxembourg)*

Global Climate Action
Final demand
Creos Luxembourg submitted the inputs for the different scenarios in line with the TYNDP 2018 scenarios. No further comments are to be reported on the final gas demand.
Residential & Commercial
Gas reduction as mentioned for the scenario.
Industrial
Stable gas consumption for industry compared to the previous year.
Transport
Gas consumption close to zero, therefore neglected for the scenario.
Non-network
No gas non-network can be reported.
Power generation
Creos Luxembourg submitted the inputs for the gas demand for power generation. As Creos Luxembourg did not have any firm capacity reserved for electrical generation, we provided zero values for each scenario. Gas demand for decentralised high-efficiency cogeneration connected to heat distribution systems will slightly increase. As we are talking about a DSO network and as the values are close to zero, they were neglected in the TYNDP gas,. This approach was coordinated with the electricity TSO.
Production
No gas production can be reported for Luxembourg.

Sustainable Transition
Final demand
Creos Luxembourg submitted the inputs for the different scenarios in line with the TYNDP 2018 scenarios. No further comments are to be reported on the final gas demand.
Residential & Commercial
Gas slight reduction as mentioned for the scenario.
Industrial
Stable gas consumption for industry compared to the previous year.
Transport
Gas consumption close to zero, therefore neglected for the scenario.
Non-network
No gas non-network can be reported.

Power generation

Creos Luxembourg submitted the inputs for the gas demand for power generation. As Creos Luxembourg did not have any firm capacity reserved, we provided zero values for each scenario. Gas demand for decentralised high-efficiency cogeneration connected to heat distribution systems will be stable. As we are talking about a DSO network and as the values are close to zero, they were neglected in the TYNDP gas. This approach was coordinated with the electricity TSO.

Production

No gas production can be reported for Luxembourg

Distributed Generation

Final demand

Creos Luxembourg submitted the inputs for the different scenarios in line with the TYNDP 2018 scenarios. No further comments are to be reported on the final gas demand.

Residential & Commercial

Gas reduction as mentioned for the scenario.

Industrial

Gas slight reduction as mentioned for the scenario.

Transport

Gas consumption close to zero, therefore neglected for the scenario.

Non-network

No gas non-network can be reported.

Power generation

Creos Luxembourg submitted the inputs for the gas demand for power generation. As Creos Luxembourg did not have any firm capacity reserved, we provided zero values for each scenario. Gas demand for decentralized high-efficiency cogeneration connected to heat distribution systems will slightly increase. As we are talking about a DSO network and as the values are close to zero, they were neglected in the TYNDP gas, This approach was coordinated with the electricity TSO.

Production

No gas production can be reported for Luxembourg

1.4.6.21. LV (Latvia)

Methodology

Final demand provided by TSO. No further comments have been reported.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

1.4.6.22. MK (FYROM)

Sustainable Transition

Final demand provided by TSO. No further comments have been reported.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

Distributed Generation, Global Climate Action

Final demand reflects TYNDP 2017 Green Revolution data.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

1.4.6.23. *MT (Malta)*

Methodology

As from 2017, Malta will be switching its main electricity generation fuel from heavy fuel oil to natural gas. In line with this objective, gas will be supplied from an LNG terminal in Delimara, consisting of a floating storage unit and on-shore regasification plant, to a new 215 MW base-load gas-fired CCGT and 149MW existing diesel engine plant which has been converted to gas.The LNG supply is considered as an intermediate solution until the Malta-Italy gas interconnection is in place.

The 'Sustainable Transition' scenario is considered as the most relevant scenario for the gasification of Malta as from 2017 initially for fuelling of the local power generating plant.

Final gas demand projections submitted for non-network and transport are based on the Malta Gas Connection Feasibility Study completed in April 2015. No infrastructure is currently in place for land transport/maritime bunkering and inland market. It is being assumed that the required infrastructure will be in place by 2025. Projections are preliminary and will need to be updated following detailed studies and market development.

Gas demand represented as non-network demand in scenarios, as network demand is reliant on the completion of projects and therefore classified as gasification demand.

Sustainable Transition

The 'Sustainable Transition' scenario is considered as the most relevant scenario for the gasification of Malta as from 2017, initially for fuelling the local power generating plant.

Final demand

Projections submitted in this sheet have been based on the Malta Gas Connection Feasibility & CBA Study completed in April 2015.

No infrastructure is currently in place for land transport/maritime bunkering and inland market. It is being assumed that the required infrastructure will be in place by 2025. Inland market is being assumed as non-network distribution of gas possibly through small-scale CNG or LNG hubs.

Projections are only preliminary and will need to be updated following detailed studies and market development.

Residential & Commercial

From preliminary studies, an inland gas distribution network is not considered feasible. Future gas demand from these two sectors is included under non-network demand.

Industrial

From preliminary studies, an inland gas distribution network is not considered feasible. Future gas demand from this sector is included under non-network demand.

Transport

Projections submitted have been based on the Malta Gas Connection Feasibility & CBA Study completed in April 2015 and is attributed to use of LNG primarily as a fuel for maritime transport and marginally for road transport.

Non-network

Projections submitted have been based on the Malta Gas Connection Feasibility & CBA Study completed in April 2015 and assumes non-network demand supplied through small inland LNG/CNG hubs.

Power generation

As from 2017, Malta will be switching its main electricity generation fuel from heavy fuel oil to natural gas. In line with this objective, gas will be supplied from an LNG terminal in Delimara, consisting of a floating storage unit and on-shore regasification plant, to a new 215 MW base-load gas-fired CCGT and 149MW existing diesel *engine plant which has been converted to gas.The LNG supply is considered as an intermediate solution until the Malta-Italy gas interconnection is in place.*

The 2-week maximum and peak day gas demand for power generation is expected to occur in the summer and not in the winter period.

Production
Not applicable for Malta.

Distributed Generation, Global Climate Action
Final demand reflects TYNDP 2017 Green Revolution data.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

1.4.6.24. NL (The Netherlands)

Methodology
Scenario data provided by TSO. No further comments have been reported.
A balance was applied to power and industrial demand to avoid double counting of CHP units between TSO submission and ENTSO-E market modelling results.

1.4.6.25. PL (Poland)

Global Climate Action
The gas demand in Poland under the Global Climate Action scenario shows moderate increase in the residential and industrial sectors. Increasing demand in these two sectors is mainly due to gasification of new areas in the country as well as substitution of coal-fired furnaces with the ones supplied with gas.
In the electricity sector a moderate growth in gas consumption is expected. Natural gas has a limited share in electricity generation in Poland. In order to meet the EU emission policy goals, there are a number of combined heat and power plants under construction or under consideration. FID projects are included in the scenario.

Sustainable Transition
The gas demand in Poland under the Sustainable Transition scenario shows more dynamic increase in the residential and industrial sectors in comparison to the Distributed Generation and Green Climate Action scenarios. The expected difference between these scenarios is due to enhanced gasification of new regions and quicker transition from coal to gas in households.
In the electricity sector a significant increase in gas consumption is expected. Natural gas has a limited share in electricity generation in Poland. In order to meet the EU emission policy goals, there are a number of combined heat and power plants under construction or under consideration. Due to more favourable conditions on the market, greater number of projects are included in the scenario.

Distributed Generation
The gas demand in Poland under the Distributed Generation scenario shows moderate increase in the residential and industrial sectors. Increasing demand in these two sectors is mainly due to gasification of new areas in the country as well as substitution of coal-fired furnaces with the ones supplied with gas.
In the electricity sector a moderate growth in gas consumption is expected. Natural gas has a limited share in electricity generation in Poland. In order to meet the EU emission policy goals, there are a number of combined heat and power plants under construction or under consideration. The projects where FID is likely, are included in the scenario.

1.4.6.26. PT (Portugal)

Methodology

Final demand

The methodology that REN used in 2016 for the demand forecasts is the same as the one used in 2015.The main drivers for the demand estimation are national policy, GDP (Gross Domestic Production), GVA (Gross Value Added) of the different sectors of the economy, the available income of the families and the extension of the NG networks in the country. For CHP the main drivers of the forecast are the power capacity installed, the number of working hours per year of the units and the rate of the progressive replacement of the fuel oil and gasoil units for natural gas and RES production ones. The assumptions considered for the application of the model were updated with the latest information available and they were also agreed with the Portuguese Energy Directorate (DGEG) during the preparation of the security of supply report of 2016.

In spite of not applying all the assumptions described in the ENTSOs' (G and E) new storylines in detail and to its fully extent, REN considers that the results obtained fulfil the request and are in line with the other countries' forecasts also. As a result, the forecast of each scenario in the Portuguese case leads to:

1. *Sustainable transition is the REN's central demand scenario;*
2. *REN's low demand scenario was used for both the Distributed and Global Climate Action scenarios.*

Power generation – general methodology

The Portuguese electricity sector is characterised by the decommissioning of all coal-fired power generation by 2030. Due to the lack of competing thermal technology, the general methodology provides different values for the Portuguese gas demand in the power generation sector that depend on the objectives of energy policy defined by the Government, which include the electricity sector demand forecast, the information on the power installed capacity for electricity production, and the fuel and CO_2 prices.

From 2017 to 2030, the main driver for gas consumption in the power generation sector is the year when the two existing coal power plants will be decommissioned, which will be determined by the energy policy defined by the Government. At the moment, taking into consideration the aim of the interlinked model to be used in gas and electricity sectors, only one scenario was considered in the information already submitted to ENTSO-E: the first coal Power Plant will be decommissioned at the end of 2021 and the second one will be decommissioned between 2026 and 2029, meaning that both coal power plants won't be in operation in 2030. The electricity demand scenario used in the gas to power simulations corresponds to the central demand forecast of the electricity sector in Portugal.

Final Remarks

REN decided to keep consistency with the national methodologies and forecasted data jointly constructed in 2016 with the Portuguese Energy Directorate (DGEG), which are the base for the national TYNDPs and other reports, like security of supply reports, risk assessment reports, etc.

The assumptions described in the ENTSOG's storylines are quite covered by REN's assumptions on its scenarios and the results obtained are in line with the other countries' forecasts also.

REN is a TSO of both gas and electricity networks and the forecasts are made based on the most updated information available. The general assumptions are defined at the same time for both the electricity and gas sectors in Portugal and the assumptions considered in the final gas demand and power generation forecasts must be kept consistent along the period considered.

Production

No production foreseen.

1.4.6.27. RO (Romania)

Sustainable Transition

Final demand

The Romanian Energy Strategy (draft document) estimates a decrease of gas share in the primary energy mix from 29% in 2015 to 27% in 2030. Nevertheless, a slight increase of gas demand (as compared to 2015) is foreseen based on the industry, transport and household consumption demand.

Residential & Commercial

Until 2030 an increase in gas consumption for house heating is estimated, limited by the house energy efficiency increase, influenced mainly by the following factors:

- *the increasing number of houses using gas for heating*
- *the increasing of the thermal comfort of the gas-heated houses.*

Industrial

For 2015-2030 an increase of industrial consumption is estimated, due to a higher demand in transports and parts and equipment industry.

Transport

For year 2030 the Romanian Energy Strategy estimates a slight increase of gas share in the total demand of energy for transport by 1.5% as compared to 2015.

Power generation

One of the strategic options of Romania is to encourage the increasing of gas share in the power mix of Romania, due to its role of transition fuel to a sustainable economy. Gas is recommended by the flexibility of the power plants using it, which can easily balance renewables' intermittent production, and the relatively small greenhouse gas emissions.

Production

Although gas production has become stable as a consequence of investments in the extension of the life span of existing fields and development of new ones, between 2016 and 2030 a slight decrease of onshore production is estimated. The maintenance of a low dependence upon imports is subject to the development of the recently discovered Black Sea gas sources.

Distributed Generation, Global Climate Action

Final demand reflects TYNDP 2017 Green Revolution data.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

1.4.6.28. RS (Serbia)

Methodology

No Serbian data was submitted during the data collection. Data reflects TYNDP 2017 information calculated based on the available information about gas exports to Serbia from the ENTSOG Transparency Platform.
Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

1.4.6.29. SE (Sweden)

Methodology

Sectoral split calculated using sectoral data methodology.
Gas demand for power generation calculated from ENTSO-E modelling results.

Global Climate Action

Final demand
Transport sector underpins a CAGR of 0.25%
Power generation

No change from our base case

Sustainable Transition

Final demand

Transport sector underpins a CAGR of 0.50%

Power generation

Power generation to increase from 2026 with a CAGR of 2%

Distributed Generation

Final demand

A total decline of -1% per year is assumed

Power generation

No change from our base case

1.4.6.30. SI (Slovenia)

Methodology

Final demand provided by TSO. No further comments have been reported.

Sectoral split calculated using sectoral data methodology.

Gas demand for power generation calculated from ENTSO-E modelling results.

1.4.6.31. SK (Slovakia)

Methodology

What relates to data sources – we have extracted some data out of a study. The study was worked out for the Slovak E-TSO.

Some data were used from the outlooks of the Ministry of Economy. Furthermore, many important data were taken out from the development plan and also from the national DSO.

1.4.6.32. UK (United Kingdom)

Methodology

All data submitted for the scenarios corresponds to the Future Energy Scenarios 2016 developed by National Grid (http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Documents-archive/).

Global Climate Action

Final demand

From National Grid's 'Gone Green' Scenario – 2016 Future Energy Scenarios.

GB + NI. Excludes Power, Moffat Export, IUK & Shrinkage.

Sustainable Transition

Final demand

From National Grid's 'Slow Progression' Scenario – 2016 Future Energy Scenarios.

GB + NI. Excludes Power, Moffat Export, IUK & Shrinkage.

Distributed Generation

Final demand

From National Grid's 'Consumer Power' Scenario – 2016 Future Energy Scenarios.

GB + NI. Excludes Power, Moffat Export, IUK & Shrinkage

ENTSOs Geographic Scope

The geographical coverage of both the ENTSO-E and ENTSOG TYNDPs goes beyond the EU28 in order to capture the dynamics from neighbouring countries that may affect the European energy networks, and as a result are included in the scenarios. The table below details the countries considered within the scenarios by the respective organisations.

Country Code	Country	ENTSO-E Scenario Scope	ENTSOG Scenario Scope
AL	Albania	Yes	
AT	Austria	Yes	Yes
AZ	Azerbaijan		Supply Only
BA	Bosnia and Herzegovina	Yes	Yes
BE	Belgium	Yes	Yes
BG	Bulgaria	Yes	Yes
CH	Switzerland	Yes	Yes
CY	Cyprus	Yes	Yes
CZ	Czech Republic	Yes	Yes
DE	Germany	Yes	Yes
DK	Denmark	Yes	Yes
DZ	Algeria		Supply only
EE	Estonia	Yes	Yes
ES	Spain	Yes	Yes
FI	Finland	Yes	Yes
FR	France	Yes	Yes
GB	Great Britain	Yes	Included in UK
GR	Greece	Yes	Yes
HR	Croatia	Yes	Yes
HU	Hungary	Yes	Yes
IE	Ireland	Yes	Yes
IS	Iceland	Yes	Yes
IT	Italy	Yes	Yes
LT	Lithuania	Yes	Yes
LU	Luxemberg	Yes	Yes
LV	Latvia	Yes	Yes
LY	Libya		Supply only
ME	Montenegro	Yes	Yes
MK	FYROM	Yes	Yes
MT	Malta	Yes	Yes
NI	Northern Ireland	Yes	Included in UK
NL	Netherlands	Yes	Yes
NO	Norway	Yes	Supply only
PL	Poland	Yes	Yes
PT	Portugal	Yes	Yes
RO	Romania	Yes	Yes
RS	Serbia	Yes	Yes
RU	Russia		Supply only
SE	Sweden	Yes	Yes
SI	Slovenia	Yes	Yes
SK	Slovakia	Yes	Yes
TR	Turkey	Yes	
UK	United Kingdom	Split as GB and NI	Yes

Table 30: ENTSO-E and ENTSOG scenario country list