April 2024

Burning the Bridge to Ostpolitik?

Stress-Testing Europe's Shift from Russian Gas to Renewables Using a Global Energy Model

Supplementary Information (SI) 2: Data inputs, sources and assumptions

OIES Paper: NG191

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Contents

Figures

Tables

A.1 High-level summary of inputs and assumptions

A partial market equilibrium model was developed for this paper that requires inputs like gas supply and electricity generation mix are taken as given (i.e., the models are not optimising for long-term capacity expansion). Thus, the models require calibration to projections of energy supply mix and demand for the modelling time horizon (see Table A. 1).

Table A. 1: Summary of input data assumptions and sources

Model inputs	Sources
Electricity model	
Demand	• Pan-European Climatic Database, Demand dataset for 2025 and 2030; available here. • Climate years were chosen according to climate scenarios developed by Ah-Voun et al. (2024). • For interpolated years (2022-2024), we took the 2021 annual electricity demand from the ENTSOE TP as the starting point and 2025 from the ERAA study.
Generation mix	• 2021 ERAA study: National Estimates 2025/2030 Scenario. • PEMMDB National Estimate Excel file; Tab “National Estimates 2025” for generation mix in 2025; Tab “National Estimates 2030” for generation mix 2030. • For interpolated years (2022-2024), we took the existing generation mix from the ENTSOE Transparency Platform (ENTSOE TP). ENTSOE TP does not provide information regarding existing battery capacity, so we use the “Database of the European Energy Storage Technologies and Facilities” to find installed battery capacity. The database is available here. • Techno-economic parameters were taken from PEMMDB (excel file), tab “Thermal Properties.” • The thermal efficiency of fossil fuel plants was taken from the JRC Open Power Plants Database v1.00, available here.
Network	• 2021 ERAA study: average of top 50 hours of projected Net Transfer Capacity for 2025/2030. • For interpolated years (2022-2024), we took the 2021 highest flow hour from the ENTSOE TP as the starting point and 2025 from the ERAA study.
Commodity prices	• 2021 ERAA study and Eikon and Bloomberg terminal (see §A.5.8)
Natural gas model	
Demand	• Demand projections and climate years were chosen according to climate scenarios developed by Ah-Voun et al. (2024). • IEA reports, Eurostat, and other sources (see §A.6.1-A.6.3)
Supply	• BP Statistical Review of World Energy (2022); National Grid ESO Future Energy Scenarios (2022); Chyong and Hobbs (2014); Chyong et al. (2023); JODI Dataset and other sources (see §A6.4)
Storage	• IEA (2019) Natural Gas Information Report; the Eikon LNG dataset; EIA’s Field Level Storage data for the U.S.A.; ENTSOG 2022 TYNDP and other sources (see §A6.5)
Transport	• ENTSO-G; ACER; Chyong and Hobbs (2014); Eikon; GIIGNL and other sources (see §A6.6)

In what follows, we give a detailed account of how the sources of input datasets were used to either calculate input parameters or to inform assumptions required for the modelling. This Appendix starts with electricity input datasets and then moves to gas datasets.

A.2 Modelling time horizon and temporal resolution

The principal objective of this study is to gauge the potential impact of a set of climate, technology and geopolitical scenarios on the European and other regional power and gas markets. Thus, the modelling horizon covers 2023-2031 at monthly time steps. In this timeframe, it is expected that essential decisions on gas supply and electricity sector capacity will likely be made in response to the interplay of risks arising from climate, technology, and geopolitical developments.

A.3 Spatial resolution and countries/regions in the model

Table A. 2 details countries and regions in the gas section of the model. Columns 1 and 3 list gas demand and production nodes, while columns 2 and 4 detail corresponding countries and regions belonging to those nodes. Thus, we have 48 gas demand nodes and 29 gas production nodes. Note that the gas demand nodes in Europe are further disaggregated into four gas demand nodes – demand in residential (RES), commercial (COM), industrial (IND), and power generation (PWR) sectors. Gas and electricity markets are coupled via the power generation nodes. On top of these nodes, the model also has other auxiliary nodes such as cross-border pipeline, LNG transhipment, and gas storage nodes (§A6.4-A.6.6), European industrial demand-side response nodes (§A.6.3), gas wholesale pricing ("hub") nodes.

Table A. 2: gas demand and production nodes in the model

Demand		Production	
Nodes in the model [1]	**Countries & regions [2]**	**Nodes in the model [3]**	**Countries & regions [4]**
Russia	Russia	Algeria	Algeria
Belgium	Belgium	Denmark	Denmark
Germany	Germany	Germany	Germany
France	France	Austria	Austria
South East Asia	Bangladesh	Hungary	Hungary
South East Asia	Brunei Darussalam	Poland	Poland
South East Asia	Indonesia	Romania	Romania
South East Asia	Malaysia	Italy	Italy
South East Asia	Myanmar	Czech Republic	Czech Republic
South East Asia	Philippines	France	France
South East Asia	Singapore	Greece	Greece
South East Asia	Thailand	Slovak Republic	Slovak Republic
South East Asia	Viet Nam	Slovenia	Slovenia
South East Asia	Other Southeast Asia	Bulgaria	Bulgaria
Middle East	Bahrain	Croatia	Croatia
Middle East	Iraq	Spain	Spain
Middle East	Iran	Central Asia	Kazakhstan
Middle East	Jordan	Central Asia	Kyrgyzstan
Middle East	Kuwait	Central Asia	Tajikistan
Middle East	Oman	Central Asia	Turkmenistan

Middle East	Qatar	Central Asia	Uzbekistan
Middle East	Saudi Arabia	South East Asia	Bangladesh
Middle East	Syrian Arab Republic	South East Asia	Myanmar
Middle East	United Arab Emirates	South East Asia	Vietnam
Middle East	Yemen	South East Asia	Malaysia
North America	Canada	South East Asia	Philippines
North America	United States	South East Asia	Thailand
North America	Mexico	South East Asia	Indonesia
Netherlands	Netherlands	South East Asia	Brunei Darussalam
Austria	Austria	South East Asia	Other Southeast Asia
Italy	Italy	Australia	Australia
Switzerland	Switzerland	Trinidad & Peru	Trinidad and Tobago
Slovenia	Slovenia	Trinidad & Peru	Peru
Spain	Spain	Middle East	Bahrain
Portugal	Portugal	Middle East	Iraq
Denmark	Denmark	Middle East	Iran
Poland	Poland	Middle East	Jordan
Czech Republic	Czech Republic	Middle East	Kuwait
Slovak Republic	Slovak Republic	Middle East	Oman
Bulgaria	Bulgaria	Middle East	Saudi Arabia
Romania	Romania	Middle East	Syrian Arab Republic
Latvia	Latvia	Middle East	United Arab Emirates
Hungary	Hungary	Middle East	Yemen
Ukraine	Ukraine	Qatar	Qatar
Turkey	Turkey	Rest of Africa	Angola
Lithuania	Lithuania	Rest of Africa	Cameroon
Greece	Greece	Rest of Africa	Côte d'Ivoire
Moldova	Moldova	Rest of Africa	Egypt
Sweden	Sweden	Rest of Africa	Equatorial Guinea
Croatia	Croatia	Rest of Africa	Gabon
Balkans	Albania	Rest of Africa	Libya
Balkans	Bosnia & Herzegovina	Rest of Africa	Morocco
Balkans	FYROM	Rest of Africa	Mozambique
Balkans	Serbia	Rest of Africa	Nigeria
Great Britain	United Kingdom	Rest of Africa	South Africa
Luxembourg	Luxembourg	Rest of Africa	Tunisia
Rest of Americas	Chile	Rest of Africa	Other Africa

Rest of Americas	Argentina	South Caucasus	Azerbaijan
Rest of Americas	Bolivia	South Caucasus	Georgia
Rest of Americas	Brazil	South Caucasus	Armenia
Rest of Americas	Colombia	Russia	Russia
Rest of Americas	Cuba	Norway	Norway
Rest of Americas	Peru	Netherlands	Netherlands
Rest of Americas	Trinidad and Tobago	North America	Canada
Rest of Americas	Venezuela	North America	United States
Rest of Americas	Other Americas	North America	Mexico
China	Hong Kong, China	UKCS	GB
China	China (People's Rep.)	GB Onshore	GB
India	India	Rest of Americas	Chile
Japan, Korea & Taiwan	Japan	Rest of Americas	Argentina
Japan, Korea & Taiwan	Korea	Rest of Americas	Bolivia
Japan, Korea & Taiwan	Taiwan	Rest of Americas	Brazil
SEM	Ireland	Rest of Americas	Colombia
SEM	Northern Ireland	Rest of Americas	Cuba
SEM	Isle of Man	Rest of Americas	Venezuela
Estonia	Estonia	Rest of Americas	Other Americas
Finland	Finland	China	China
Algeria	Algeria	India	India
Rest of Africa	Angola	Japan, Korea & Taiwan	Japan
Rest of Africa	Congo	Japan, Korea & Taiwan	Korea
Rest of Africa	Côte d'Ivoire	Japan, Korea & Taiwan	Taiwan
Rest of Africa	Egypt	Ireland	Ireland
Rest of Africa	Gabon	Balkans	Albania
Rest of Africa	Libya	Balkans	Bosnia and Herzegovina
Rest of Africa	Morocco	Balkans	FYROM
Rest of Africa	Mozambique	Balkans	Serbia
Rest of Africa	Nigeria	Ukraine	Ukraine
Rest of Africa	South Africa	Pakistan	Pakistan
Rest of Africa	Tanzania	Belarus	Belarus

Rest of Africa	Tunisia	Turkey	Turkey
Rest of Africa	Other Africa	Israel	Israel
Central Asia	Kazakhstan	PNG	Papua New Guinea
Central Asia	Kyrgyzstan	SEM	Ireland
Central Asia	Tajikistan	SEM	Northern Ireland
Central Asia	Turkmenistan	SEM	Isle of Man
Central Asia	Uzbekistan		
South Caucasus	Azerbaijan		
South Caucasus	Georgia		
South Caucasus	Armenia		
Norway	Norway		
Australia	Australia		
Pakistan	Pakistan		
Belarus	Belarus		
Israel	Israel		

A.4 Climate scenarios for European countries

Explicitly considering possible variations in weather scenarios (so-called climate years, CY) is crucial for gas and electricity markets as both become increasingly dependent on such variability. Energy (gas and electricity) demand and the supply of electricity from variable renewables (wind and solar) and hydro are primarily driven by fluctuations in weather (outside temperature, precipitation, wind speed, and solar radiation), which exhibit significant inter-annual variations (IAV) (see Ah-Voun et al., 2024).

Following Ah-Voun et al. (2024), inter-annual variations in the outside temperature (the primary driver of residential gas and electricity demand) were chosen as critical drivers in constructing the weather scenarios. And so, to be consistent with this set of weather scenarios, the same set of historical years for electricity demand and capacity factors for wind, solar and hydro generation was chosen. A publicly available dataset published by ENTSO-e called “Pan-European Climatic Database (PECD 2021.3)” was used for this (see De Felice, 2022). This comprehensive dataset contains more than 30 climate years of hourly electricity demand, wind and solar capacity factors, and hydro energy inflows for individual electricity bidding zones (more than 140) in Europe. PECD is central to the 2022 TYNDP and the 2021 ERAA modeling studies.

Unfortunately, some of the parameters we need for the modelling do not cover all climate years in our climate scenarios. The PECD dataset has capacity factors for wind and solar rooftop PV from 1982 to 2019 and solar CSP from 1982 to 2018. Hydro energy (water) inflow data covers from 1982 to 2017 in most instances but for some countries till 2016. Electricity demand data covers 1982 to 2016. Thus, only the electricity demand and hydro inflow for the mild climate scenario are affected by the PECD limitation for the following countries: DE, ES, FR, GB, GR, LV, NO, and PL. Instead of those missing climate years (2017, 2018 and 2019 in the mild weather scenario), the normal climate scenario was used. Regarding gas security of supply, substituting mild for normal for these countries only slightly overestimated the impact of a gas shortage and only in the electricity market (a normal climate year should have higher electricity demand than in a mild climate year).

A.5 Electricity market modelling data & assumptions

A.5.1 Electricity demand

We explicitly model 29 electricity supply and demand nodes corresponding to 29 countries in Europe (see Table A. 3). Electricity demand projection follows the "National Estimates" (NE) 2025 and 2030 scenario developed as part of the Pan-European Climatic Database (PECD 2021.3) for the 2021 "European Resource Adequacy Assessment" (ERAA) study by ENTSO-e. PECD is also central to the 2022 joint ENTSO-e (electricity) and ENTSO-g (gas) "Ten Year Network Development Plan" (TYNDP) study. The two studies share important common assumptions and scenarios, such as "National Trends" (NT) in TYNDP 2022 and "National Estimates" (NE) in the ERAA study.

The NT and NE scenarios are bottom-up scenarios developed for the medium-term projection, covering 2025 and 2030 (NE/NT). These scenarios depend on detailed and systematic data collection processes by national gas and electricity Transmission System Operators (TSOs), reflecting the latest policy- and market-driven developments discussed at the national level at the end of 2020. This includes, but is not limited to, the National Energy and Climate Plans (NECPs) and additional developments and ambitions (such as national hydrogen strategies)[1]. We use NE's estimate of national electricity demand (annual values are shown in Table A. 3 for normal CY).

Table A. 3: Annual electricity demand projection (TWh) for European countries in the model (normal CY)

Country	2023	2024	2025	2026	2027	2028	2029	2030	2031
Austria	68	70	73	75	77	79	80	82	82
Belgium	87	88	89	90	91	93	94	95	95
Bulgaria	36	35	34	34	35	35	36	36	36
Switzerland	63	62	62	62	63	63	63	64	64
Czech Republic	69	71	72	73	73	74	74	75	75
Germany	529	542	554	560	566	572	578	584	584
Denmark	40	42	43	45	47	49	51	53	53
Estonia	9	9	9	9	9	9	9	9	9
Spain	250	254	257	258	259	260	261	261	261
Finland	89	92	94	97	100	102	105	108	108
France	466	466	466	468	470	471	473	475	475
Great Britain	296	292	288	292	297	301	306	310	310
Greece	54	56	57	58	59	60	60	61	61
Croatia	18	18	18	18	18	18	18	18	18
Hungary	46	47	47	48	49	50	51	51	51
Island of Ireland (SEM)	42	44	46	47	48	49	50	51	51
Italy	307	316	324	326	327	328	329	330	330
Lithuania	13	13	14	14	14	14	15	15	15

[1] For further details on these scenarios see https://2022.entsos-tyndp-scenarios.eu/wp-content/uploads/2022/04/TYNDP_2022_Scenario_Building_Guidelines_Version_April_2022.pdf

Luxembourg	6	7	8	8	8	8	9	9	9
Latvia	7	7	8	8	8	8	8	8	8
Netherlands	122	130	138	138	139	139	140	140	140
Norway	145	148	151	154	157	159	162	165	165
Poland	173	172	171	173	175	178	180	182	182
Portugal	50	50	51	52	53	54	55	56	56
Romania	61	62	62	63	63	64	65	65	65
Slovenia	14	15	15	15	15	16	16	16	16
Slovakia	29	29	29	30	30	31	31	31	31
Sweden	143	145	147	148	149	150	151	152	152
Ukraine*	88	88	88	88	88	88	88	88	88

Notes: *due to the lack of scenarios around Ukraine's energy sector development and, importantly, due to uncertainties created by the war in Ukraine, we assume that electricity demand in Ukraine will be at least 40% lower than the pre-war demand level, which is in line with the observed trend in electricity demand (IEA, 2022); for Ukraine, we use 2019 hourly demand profile which also comes from IEA (2022).

Since PECD only covers electricity demand for two spot years – 2025 and 2030 – we use 2021 historic electricity demand and the projected one for 2025 to linearly interpolate for years 2022-2024, while for interpolation of 2026-2029, we use annual electricity demand for 2025 and 2030. The year 2031 is assumed to have the same annual electricity demand as in 2030.[2] The procedure for interpolation is as follows:

1. We choose a normal climate year for both 2025 and 2030 to do the interpolation (for results of this interpolation, see Table A. *3*);
2. As a next step to match our calendar years with the chosen climate scenarios, we use the annual interpolated demand values calculated in step 1 and proportionally adjust the corresponding hourly demand time series in the PECD; more specifically:
3. To calculate the hourly demand time series for the years 2022-2024, we use their corresponding annual interpolated values (step 1) and adjust the hourly demand time series in the PECD for the year 2025, ensuring that we choose consistent climate years;
4. Similarly, to calculate the hourly demand time series for 2026-2029, we use their corresponding annual values (step 1) and adjust the hourly demand in the PECD for 2030, considering our mapping between the years and climate scenarios.

The above procedures ensure that we separate the effects of energy policy scenarios on demand from the effects of climate on inter-annual demand variations. That is why we assume a normal climate scenario for all years in the modelling and only then adjust for possible impacts of a climate scenario on the electricity demand of a particular year in the modelling horizon.

[2] 2031 was added to the modelling horizon so that to fully cover the last gas year which is Oct-2030 till Sept-2031.

A.5.2 Generation capacity

We follow the 2021 ERAA NE scenario, which provides a generation mix for each country for 2025 and 2030[3]. We take the existing generation mix (2021) and the 2025 forecasted mix to derive the generation mix for 2022-2024 (by linear interpolation), and we use 2025 and 2030 to calculate the generation mix for 2026-2029 (by linear interpolation). The 2031 generation mix is assumed to be the same as the generation mix in 2030.

For Ukraine, we assume the existing generation mix in the modelling. This assumption should not impact as long as commercial power exchange between Ukraine and European countries is limited.[4] Table A. 4 shows the generation mix at the EU27+ (Norway, Switzerland, and the UK) level for 2023-2031 using the existing generation mix and the 2025 and 2030 projections to interpolate for the years in between.

Table A. 4: Generation and storage capacity for EU27, Norway, Switzerland and the UK: ERAA 2021 NE scenario

	2023	2024	2025	2026	2027	2028	2029	2030	2031
Generation capacity (GW)									
Biomass	19	13	7	7	7	7	7	7	7
Nuclear	109	106	103	101	100	99	98	97	97
Offshore Wind	34	40	47	57	68	79	90	101	101
Onshore Wind	209	230	251	263	276	288	300	312	312
Other_RES	18	27	35	36	37	38	38	39	39
Solar_PV	178	205	233	260	288	315	342	369	369
Solar Thermal	4	4	5	6	7	8	8	9	9
Lignite existing	42	38	35	33	30	28	26	24	24
Hard Coal existing	58	46	35	32	30	28	25	23	23
Gas existing	205	189	172	172	171	170	170	169	169
Gas CCGT new	1	2	3	4	4	5	6	7	7
Gas OCGT new	1	1	2	2	2	2	3	3	3
Fossil Oil existing	12	9	6	6	6	6	5	5	5
Hydro Reservoir	66	66	66	66	66	66	66	66	66
Hydro Run of River&Pondage	51	51	51	51	51	51	52	52	52
Hydro PS (open loop)	66	66	66	66	67	68	69	69	69

[3] Generation mix is taken from this source: https://eepublicdownloads.azureedge.net/clean-documents/sdc-documents/ERAA/PEMMDB%20National%20Estimates.xlsx (Tab "National Estimates 2025" for 2025 and tab "National Estimates 2030" for 2030)

[4] Current electricity export capacity between Ukraine and ENTSO-e grid is 1690 MW (Popik, 2022).

Hydro_PS (closed_loop)	29	29	29	31	32	34	35	37	37
Battery	9	12	16	22	27	33	38	44	44
Energy Storage (GWh)									
Hydro Reservoir	75,990	75,990	75,990	75,992	75,994	75,995	75,997	75,999	75,999
Hydro Run of River&Pondage	84	84	84	84	84	84	84	84	84
Hydro PS (open loop)	108,475	108,475	108,475	108,928	109,381	109,834	110,287	110,740	110,740
Hydro_PS (closed_loop)	544	544	544	549	554	559	564	569	569
Battery	17	24	30	44	58	72	86	100	100

A.5.3 Generation techno-economic parameters

This section outlines the methodology and assumptions concerning techno-economic parameters of electricity generation technologies modelled.

A.5.3.1Thermal efficiency of generating units

We use the JRC Open Power Plants Database (2021) (JRC-PPDB-OPEN v1.00) (Kanellopoulos et al., 2019) as a primary plant and unit thermal efficiency source. The database has 1315 existing fossil fuel generation units, of which 1223 (93%) units have thermal efficiency information. To fill in the missing information for the rest of the units, we use a simple regression analysis to gauge the thermal efficiency of these units depending either on their commission dates or on installed capacity (unit level).

Thus, we split our generation dataset into two main categories: (i) existing fleet per generation type (ii) and new generation fleet per type (Table A. 5 details generation types in the electricity modelling). The existing fleet has capacity-weighted average efficiency, whereas the new generation fleet will have "new" generation units (e.g., an efficiency value of 60% in line 16 in Table A. 5 will be assigned to new gas-fired capacity addition). Since our model runs at the monthly resolution, most techno-economic parameters (such as commitment time and ramp rates) do not influence modelling results. We, therefore, model the generation fleet at the fuel class aggregation level (column 2, Table A. 5) except for the new gas-fired generation, for which it is desirable to differentiate between CCGT and OCGT. OCGT has higher flexibility parameters at the sub-hourly level[5] (columns 9 and 10, Table A. 5) but lower efficiency and, hence, higher gas demand per output unit than CCGTs. We use thermal efficiency, minimum commitment time, minimum stable generation, and ramp rates parameters (as defined in Table A. 5) to assign existing gas-fired generation units to these two generation technologies and use the existing shares to split gas generation into CCGT and OCGT capacity for 2025 and 2030. In most countries we model, gas-fired generation capacity is expected to decline (i.e., no new gas generation is expected). Only in seven countries – Belgium, Bulgaria, Czech Republic, Greece, Latvia, Poland, and Romania - is additional gas generation capacity expected.

[5] OCGT will be required in a high share VRE power system we anticipate in Europe

Table A. 5: Generation techno-economic parameters

	Fuel	Type	Standard efficiency in NCV terms (%)	CO_2 emission factor (kg / Net GJ)	Min Time on (hours)	Min Time off (hours)	Minimum stable generation (%of max power)	Ramp up (% of max output power/min)	Ramp down (% of max output power/min)	Variable O&M cost (€/MWh)	Start-up fuel consumption (Net GJ /MW. start)	Start-up cost (€ /MW. Start)	Self-cons. (% of installed capacity)
1	Nuclear	-	33%	0	12	12	40%	5%	5%	9	14.0	21	5%
2	Hard Coal	old 1	35%	94	8	8	40%	2%	5%	3.3	18.0	70	5%
3	Hard Coal	old 2	40%	94	6	6	40%	2%	5%	3.3	18.0	50	5%
4	Hard Coal	new	46%	94	5	5	25%	4%	5%	3.3	18.0	42	5%
5	Hard Coal	CCS	38%	9.4	7	7	25%	4%	5%	6.6	18.0	50	n.a.
6	Lignite	old 1	35%	101	11	11	50%	2%	5%	3.3	18.0	70	5%
7	Lignite	old 2	40%	101	9	9	50%	2%	5%	3.3	18.0	50	5%
8	Lignite	new	46%	101	8	8	50%	2%	5%	3.3	18.0	42	5%
9	Lignite	CCS	38%	10.1	10	10	50%	2%	5%	6.6	18.0	50	5%
10	Gas	Conv. old 1	36%	57	5	5	20%	15%	15%	1.1	7.6	68	5%
11	Gas	Conv. old 2	41%	57	5	5	20%	15%	15%	1.1	7.6	45	5%
12	Gas	CCGT old 1	40%	57	3	3	50%	2%	5%	1.6	7.6	73	5%
13	Gas	CCGT old 2	48%	57	3	3	50%	2%	5%	1.6	7.6	43	5%
14	Gas	CCGT* 1	56%	57	2	2	40%	4%	5%	1.6	7.6	25	5%
15	Gas	CCGT* 2	58%	57	2	2	40%	4%	5%	1.6	7.6	25	5%
16	Gas	CCGT new	60%	57	2	2	40%	4%	5%	1.6	7.6	25	5%
17	Gas	CCGT CCS	51%	5.70	4	4	40%	4%	5%	3.2	7.6	43	5%
18	Gas	OCGT old	35%	57	1	1	50%	8%	8%	1.6	0.2	52	5%

19	Gas	OCGT new	42%	57	1	1	40%	12%	12%	1.6	0.2	20	5%
20	Light oil	-	35%	78	1	1	50%	8%	8%	1.1	0.2	36	5%
21	Heavy oil	old 1	35%	78	3	3	50%	8%	8%	3.3	7.6	70	5%
22	Heavy oil	old 2	40%	78	3	3	50%	8%	8%	3.3	7.6	50	5%
23	Oil shale	old	29%	100	11	11	50%	8%	8%	3.3	18.0	60	5%
24	Oil shale	new	39%	100	8	8	50%	8%	8%	3.3	18.0	42	5%
25	Fuel cell	Hydrogen	60%	0	0	0	0%	0%	0%	8.4	0.0	0	n.a.

Source: ENTSO-e (2021). The original data file is available here.

Notes: *present CCGTs; for start-up values, we assume a warm start, in line with ERAA's assumption that without the capability to model different types of start-ups (hot, warm and cold), a warm start should be assumed.

A.5.3.2 Forced and planned outage modelling

ERAA provides generic information about forced and planned outages for generation types as outlined in Table A. 5. We derate generation capacity by the annual rate (days for planned outage divided by 365) to reflect the plant's unavailability due to planned outage. As for forced outage (FO), ideally, a Monte-Carlo simulation should be performed, or a stochastic unit commitment and economic dispatch model should be used to model forced outages explicitly. Given our focus on the security of supply modelling and the limitation of our deterministic model with a focus on global gas markets, we take a simplified (deterministic) approach concerning FO. We take the mean time to repair (column 5, Table A. 5) and derate the generation fleet capacity accordingly (e.g., if the mean time to repair for nuclear technology is seven days, then we derate the whole fleet capacity by 7/365, ca. 2%) for every year in the modelling horizon. While this deterministic approach to derate the installed capacity somewhat underestimates the impact of FO on the security of supply, the probability of these FO is relatively low (column 4) compared to our assumed derating for every year in our ten years of modelling horizon.[6]

Table A. 5: Planned and forced outage[7] of various generation types

	Fuel	Type	Unavailability			
			Forced outage		Planned outage	
			Annual rate	Mean time to repair	Annual rate	Winter
			%	Days	Days	% of annual rate
1	Nuclear	-	5%	7	54	15%
2	Hard Coal	old 1	10%	1	27	15%
3	Hard Coal	old 2	10%	1	27	15%
4	Hard Coal	new	7.50%	1	27	15%
5	Hard Coal	CCS	7.50%	1	27	15%
6	Lignite	old 1	10%	1	27	15%
7	Lignite	old 2	10%	1	27	15%
8	Lignite	new	7.50%	1	27	15%
9	Lignite	CCS	7.50%	1	27	15%
10	Gas	Conv. old 1	8%	1	27	15%
11	Gas	Conv. old 2	8%	1	27	15%
12	Gas	CCGT old 1	8%	1	27	15%
13	Gas	CCGT old 2	8%	1	27	15%
14	Gas	CCGT* 1	5%	1	27	15%
15	Gas	CCGT* 2	5%	1	27	15%
16	Gas	CCGT new	5%	1	27	15%
17	Gas	CCGT CCS	5%	1	27	15%

[6] E.g., according to ENTSO-e (2021)., there is 5% chance that nuclear fleet will be taken down for 7 days due to FO in a particular year. Put this differently, there is one year in 20 when nuclear fleet will be taken off for 7 days due to FO. Another thing to note is that the probability of all units going down is extremely low and the information given by ERAA is applicable to unit level probability of FO.
[7] Since we do not have planned and FO rates for biomass plants, we took hard coal (new) outage rates and apply it to biomass

18	Gas	OCGT old	8%	1	13	15%
19	Gas	OCGT new	5%	1	13	15%
20	Light oil	-	8%	1	13	15%
21	Heavy oil	old 1	10%	1	27	15%
22	Heavy oil	old 2	10%	1	27	15%
23	Oil shale	old	10%	1	27	15%
24	Oil shale	new	7.50%	1	27	15%
25	Fuel cell	Hydrogen	2.50%	1	7	0%

Notes: Mean time to repair means the duration of a forced outage; forced outage rates are expressed as a single percentage (probability) for each generation unit for a particular year.

Source: ENTSO-e (2021).

A.5.4 Energy storage, hydropower and other flexibility technologies

A.5.4.1 Battery electrical storage

ERAA NE scenario only provides battery capacity projections for 2025 and 2030. To estimate battery capacity for 2022-2024, we need battery installed capacity for 2021 – for this, we use information in the *"Database of the European energy storage technologies and facilities"* by considering only operational electrochemical battery projects.[8]

We assume that battery storage has 90% roundtrip efficiency, which aligns with the ERAA 2021 study (ENTSO-e, 2021).

A.5.4.2 Demand side response

There are two types of DSR – load shifting (from peak to off-peak), which can be modelled as storage units, and peak shaving, which can be modelled as a virtual power station (in that a reduction in MWh of consumption is equivalent to an additional MWh of production). ERAA assumes only the second type of DSR (i.e., peak shaving) (ERAA, 2021[9], p.13 and p.37). The dataset for DSR provided by national TSOs (not all countries have either provided DSR information or do not have such technology yet) contains the following information (ERAA, 2021, p.13):

- the maximum DSR capacity [MW];
- the day ahead price [EUR/MWh];
- the actual availability [MW] for all hours of the year;
- the maximum number of hours the DSR source can be used daily (default: 24 hours).

Up to ten activation price bands for DSR are considered in the ERAA modelling, and TSOs provided inputs regarding DSR capacity and availability for each band. The complete input dataset for DSR is available here. We use the inputs from this dataset to model DSR (peak shaving).

[8] https://data.europa.eu/data/datasets/database-of-the-european-energy-storage-technologies-and-facilities?locale=en

[9] Page 13: *"From a modelling perspective, DSR is equal to any other generation asset but with an activation price that is higher than the marginal cost of most other generation categories and with an availability rating that limits the actual DSR capacity in any given hour."* Page 37: *"DSR is only modelled as demand reduction potential in the case of high prices, whereas shiftable load is not yet considered in the simulations. Shiftable load enables the rescheduling of demand from a period with high prices to a period with lower prices (i.e. from a period with higher adequacy concerns to a period with lower adequacy concerns). For the moment, shiftable load, e.g. EV demand, is considered within the demand forecasting methodology (from periods with peak demand to periods with lower demand)."* Available here: https://eepublicdownloads.azureedge.net/clean-documents/sdc-documents/ERAA/ERAA_2021_Annex_3_Methodology.pdf

If we need to aggregate nodes to a country level, we apply a capacity-weighted average to calculate the country-level activation prices. The country-level DSR capacity is the sum of capacity at the node level.

A.5.4.3 Hydropower modelling

Following ERAA's hydro modelling methodology (ENTSOE, 2019), we consider the following hydropower technologies:

- Hydro Run-of-River and Pondage (Hydro RoR): Plants that do not have pumping capacity, do not have reservoirs, or have small reservoirs with a maximum of 24 hours of storage.
- Hydro Reservoir: This category contains hydro plants that have reservoirs but do not have pumping capacity. They are generation plants with a storage capacity higher than 24 hours.
- Hydro Open-loop Pump Storage (Hydro PS open-loop): This category contains hydro plants with pumping capacity, regardless of reservoir size and natural inflows.
- Hydro Closed-loop Pump Storage (Hydro PS closed-loop): This category contains hydro plants with pumping capacity, irrespective of reservoir size, and that do not have natural inflows.

For our modelling, we rely on the PECD Hydro dataset that has four key parameters we need to model hydro generation technologies: (i) pumping (charge) capacity, turbining (discharge) capacity, storage capacity, and hydro energy inflows. According to the ENTSO-e (2021; p.14[10]) methodology, forced outages and planned maintenance of hydro technologies are included in the (weekly) maximum generation constraints.

While hydro energy inflows are reported as a supplementary data file (because inflows are usually daily or weekly time series for every country we model, including all climate years), pumping, turbining and storage capacity for all hydro technologies are reported in Table A. 7 – Table A. 10. Lastly, we assume 75% for pumping efficiency, in line with LeighFisherJacobs' report (Leigh Fisher Jacobs, 2016; p.70).

[10] https://eepublicdownloads.azureedge.net/clean-documents/sdc-documents/ERAA/ERAA_2021_Annex_3_Methodology.pdf

Table A. 6: Hydro Run-of-River input parameters

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AT	6.1;0;5.6	6.1;0;5.6	6.1;0;5.6	6.1;0;5.6	6.1;0;5.6	6.1;0;5.6	6.1;0;5.6	6.1;0;5.6	6.1;0;5.6	6.1;0;5.6
BE	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0
BG	0.5;0;0	0.5;0;0	0.5;0;0	0.5;0;0	0.5;0;0	0.5;0;0	0.5;0;0	0.5;0;0	0.5;0;0	0.5;0;0
CH	4.2;0;0	4.2;0;0	4.2;0;0	4.2;0;0	4.2;0;0	4.2;0;0	4.2;0;0	4.2;0;0	4.2;0;0	4.2;0;0
CZ	0.4;0;0	0.4;0;0	0.4;0;0	0.4;0;0	0.4;0;0	0.4;0;0	0.4;0;0	0.4;0;0	0.4;0;0	0.4;0;0
DE	4.7;0;0	4.7;0;0	4.7;0;0	4.7;0;0	4.7;0;0	4.7;0;0	4.7;0;0	4.7;0;0	4.7;0;0	4.7;0;0
DK	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
EE	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
ES	3.5;0;0.6	3.5;0;0.6	3.5;0;0.6	3.5;0;0.6	3.5;0;0.6	3.6;0;0.6	3.6;0;0.6	3.6;0;0.6	3.6;0;0.6	3.6;0;0.6
FI	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
FR	13.6;0;13.6	13.6;0;13.6	13.6;0;13.6	13.6;0;13.6	13.6;0;10.9	13.6;0;8.2	13.6;0;5.4	13.6;0;2.7	13.6;0;0	13.6;0;0
GB	2;0;0	2;0;0	2;0;0	2;0;0	2;0;0	2;0;0	2.1;0;0	2.1;0;0	2.1;0;0	2.1;0;0
GR	0.4;0;0	0.4;0;0	0.4;0;0	0.4;0;0	0.4;0;0	0.4;0;0	0.4;0;0	0.4;0;0	0.4;0;0	0.4;0;0
HR	0.4;0;4	0.4;0;4	0.4;0;4	0.4;0;4	0.4;0;4	0.4;0;4	0.4;0;4	0.4;0;4	0.4;0;4	0.4;0;4
HU	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0
IT	6.2;0;0	6.2;0;0	6.2;0;0	6.2;0;0	6.2;0;0	6.2;0;0	6.2;0;0	6.2;0;0	6.2;0;0	6.2;0;0
LT	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0	0.1;0;0
LU	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
LV	1.6;0;16	1.6;0;16	1.6;0;16	1.6;0;16	1.6;0;16	1.6;0;16	1.6;0;16	1.6;0;16	1.6;0;16	1.6;0;16
NL	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
NO	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
PL	0.5;0;0	0.5;0;0	0.5;0;0	0.5;0;0	0.5;0;0	0.5;0;0	0.5;0;0	0.5;0;0	0.5;0;0	0.5;0;0
PT	0.8;0;6.4	0.8;0;6.4	0.8;0;6.4	0.8;0;6.4	0.8;0;6.4	0.8;0;6.4	0.8;0;6.4	0.8;0;6.4	0.8;0;6.4	0.8;0;6.4
RO	3.3;0;0	3.3;0;0	3.3;0;0	3.3;0;0	3.3;0;0	3.3;0;0	3.4;0;0	3.4;0;0	3.4;0;0	3.4;0;0
SE	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
SEM	0.2;0;0	0.2;0;0	0.2;0;0	0.2;0;0	0.2;0;0	0.2;0;0	0.2;0;0	0.2;0;0	0.2;0;0	0.2;0;0
SI	1.2;0;3.4	1.2;0;3.4	1.2;0;3.4	1.2;0;3.4	1.2;0;3.4	1.2;0;3.4	1.2;0;3.4	1.3;0;3.4	1.3;0;3.4	1.3;0;3.4
SK	1.5;0;11.8	1.5;0;11.8	1.5;0;11.8	1.5;0;11.8	1.5;0;11.8	1.5;0;11.8	1.5;0;11.8	1.6;0;11.8	1.6;0;11.8	1.6;0;11.8

Notes: the first number is turbining capacity (MW); the second number is pumping capacity (MW); the third number is storage capacity (GWh); if there are no values, that means “0” capacity.

Table A. 7: Hydro reservoir input parameters

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AT	2.5;0;0.8	2.5;0;0.8	2.5;0;0.8	2.5;0;0.8	2.5;0;0.8	2.5;0;0.8	2.5;0;0.8	2.5;0;0.8	2.5;0;0.8	2.5;0;0.8
BE	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
BG	1.3;0;0.8	1.3;0;0.8	1.3;0;0.8	1.3;0;0.8	1.3;0;0.8	1.3;0;0.8	1.3;0;0.8	1.3;0;0.8	1.3;0;0.8	1.3;0;0.8
CH	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
CZ	0.7;0;0	0.7;0;0	0.7;0;0	0.7;0;0	0.7;0;0	0.7;0;0	0.7;0;0	0.7;0;0	0.7;0;0	0.7;0;0
DE	1.3;0;0.3	1.3;0;0.3	1.3;0;0.3	1.3;0;0.3	1.3;0;0.3	1.3;0;0.3	1.3;0;0.3	1.3;0;0.3	1.3;0;0.3	1.3;0;0.3
DK	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
EE	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
ES	11;0;11.6	11;0;11.6	11;0;11.6	11;0;11.6	11;0;11.6	11;0;11.6	11;0;11.6	11;0;11.6	11;0;11.6	11;0;11.6
FI	3.2;0;5.5	3.2;0;5.5	3.2;0;5.5	3.2;0;5.5	3.2;0;5.5	3.2;0;5.5	3.2;0;5.5	3.2;0;5.5	3.2;0;5.5	3.2;0;5.5
FR	9.7;0;10.1	9.7;0;10.1	9.7;0;10.1	9.7;0;10.1	9.5;0;10	9.4;0;10	9.2;0;10	9;0;10	8.8;0;10	8.8;0;10
GB	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
GR	2.5;0;3.6	2.5;0;3.6	2.5;0;3.6	2.5;0;3.6	2.5;0;3.6	2.6;0;3.6	2.6;0;3.6	2.7;0;3.6	2.7;0;3.6	2.7;0;3.6
HR	1.6;0;2	1.6;0;2	1.6;0;2	1.6;0;2	1.6;0;2	1.7;0;2	1.8;0;2	1.9;0;2	1.9;0;2	1.9;0;2
HU	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
IT	9.6;0;5.6	9.6;0;5.6	9.6;0;5.6	9.6;0;5.6	9.6;0;5.6	9.6;0;5.6	9.6;0;5.6	9.6;0;5.6	9.6;0;5.6	9.6;0;5.6
LT	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
LU	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
LV	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
NL	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
NO	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
PL	0.3;0;0	0.3;0;0	0.3;0;0	0.3;0;0	0.3;0;0	0.3;0;0	0.3;0;0	0.3;0;0	0.3;0;0	0.3;0;0
PT	3.8;0;1.3	3.8;0;1.3	3.8;0;1.3	3.8;0;1.3	3.8;0;1.3	3.8;0;1.3	3.8;0;1.3	3.8;0;1.3	3.8;0;1.3	3.8;0;1.3
RO	2.5;0;2.4	2.5;0;2.4	2.5;0;2.4	2.5;0;2.4	2.6;0;2.4	2.6;0;2.4	2.6;0;2.4	2.6;0;2.4	2.6;0;2.4	2.6;0;2.4
SE	6.4;0;31.9	16.4;0;31.9	16.4;0;31.9	16.4;0;31.9	16.4;0;31.9	16.4;0;31.9	16.4;0;31.9	16.4;0;31.9	16.4;0;31.9	16.4;0;31.9
SEM	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
SI	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
SK	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0

Notes: The first number is turbining capacity (MW), the second number is pumping capacity (MW), and the third number is storage capacity (TWh).

Table A. 8: Hydro pump storage (open loop)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AT	3.9;3.1;1.7	3.9;3.1;1.7	3.9;3.1;1.7	3.9;3.1;1.7	4.4;3.6;1.7	4.8;4;1.7	5.2;4.4;1.7	5.6;4.8;1.7	6;5.2;1.7	6;5.2;1.7
BE	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
BG	0.5;0.1;0.3	0.5;0.1;0.3	0.5;0.1;0.3	0.5;0.1;0.3	0.5;0.1;0.3	0.5;0.1;0.3	0.5;0.1;0.3	0.5;0.1;0.3	0.5;0.1;0.3	0.5;0.1;0.3
CH	10.3;2.1;8.8	10.3;2.1;8.8	10.3;2.1;8.8	10.3;2.1;8.8	10.4;2.1;8.8	10.5;2.1;8.8	10.6;2.1;8.8	10.6;2.1;8.8	10.7;2.1;8.8	10.7;2.1;8.8
CZ	0.5;0.4;0	0.5;0.4;0	0.5;0.4;0	0.5;0.4;0	0.5;0.4;0	0.5;0.4;0	0.5;0.4;0	0.5;0.4;0	0.5;0.4;0	0.5;0.4;0
DE	1.6;1.4;0.4	1.6;1.4;0.4	1.6;1.4;0.4	1.6;1.4;0.4	1.6;1.4;0.4	1.6;1.4;0.4	1.6;1.4;0.4	1.6;1.4;0.4	1.6;1.4;0.4	1.6;1.4;0.4
DK	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
EE	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
ES	2.7;2.4;6	2.7;2.4;6	2.7;2.4;6	2.7;2.4;6	2.7;2.4;6	2.7;2.4;6	2.7;2.4;6	2.7;2.4;6	2.7;2.4;6	2.7;2.4;6
FI	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
FR	1.8;1.8;0.1	1.8;1.8;0.1	1.8;1.8;0.1	1.8;1.8;0.1	1.8;1.8;0.1	1.8;1.8;0.1	1.8;1.8;0.1	1.8;1.8;0.1	1.8;1.8;0.1	1.8;1.8;0.1
GB	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
GR	0.7;0.7;0	0.7;0.7;0	0.7;0.7;0	0.7;0.7;0	0.7;0.7;0	0.7;0.7;0	0.7;0.7;0	0.7;0.7;0	0.7;0.7;0	0.7;0.7;0
HR	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0
HU	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
IT	3.3;2.1;0.3	3.3;2.1;0.3	3.3;2.1;0.3	3.3;2.1;0.3	3.3;2.1;0.3	3.3;2.1;0.3	3.3;2.1;0.3	3.3;2.1;0.3	3.3;2.1;0.3	3.3;2.1;0.3
LT	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
LU	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
LV	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
NL	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
NO	34.7;1.1;87.8	34.7;1.1;87.8	34.7;1.1;87.8	34.7;1.1;87.8	35.4;1.1;88.1	36;1.1;88.5	36.7;1.1;88.9	37.4;1.1;89.2	38;1.1;89.6	38;1.1;89.6
PL	0.2;0.2;0	0.2;0.2;0	0.2;0.2;0	0.2;0.2;0	0.2;0.2;0	0.2;0.2;0	0.2;0.2;0	0.2;0.2;0	0.2;0.2;0	0.2;0.2;0
PT	3.8;3.6;2	3.8;3.6;2	3.8;3.6;2	3.8;3.6;2	3.8;3.6;2	3.8;3.6;2	3.8;3.6;2	3.8;3.6;2	3.8;3.6;2	3.8;3.6;2
RO	0.8;0.1;1	0.8;0.1;1	0.8;0.1;1	0.8;0.1;1	0.8;0.1;1.1	0.8;0.1;1.2	0.8;0.1;1.3	0.8;0.1;1.4	0.8;0.1;1.5	0.8;0.1;1.5
SE	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
SEM	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
SI	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
SK	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0	0.3;0.2;0

Notes: the first number is turbining capacity (MW); the second number is pumping capacity (MW); the third number is storage capacity (GWh); if there are no values, that means “0” capacity.

Table A. 9: Hydro pump storage (closed loop)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
AT	0.3;0.3;1.8	0.3;0.3;1.8	0.3;0.3;1.8	0.3;0.3;1.8	0.3;0.3;1.8	0.3;0.3;1.8	0.3;0.3;1.8	0.3;0.3;1.8	0.3;0.3;1.8	0.3;0.3;1.8
BE	1.2;1.2;5.3	1.2;1.2;5.3	1.2;1.2;5.3	1.2;1.2;5.3	1.2;1.2;5.3	1.2;1.2;5.3	1.2;1.2;5.3	1.2;1.2;5.3	1.2;1.2;5.3	1.2;1.2;5.3
BG	0.9;0.8;9.4	0.9;0.8;9.4	0.9;0.8;9.4	0.9;0.8;9.4	0.9;0.8;9.4	0.9;0.8;9.4	0.9;0.8;9.4	0.9;0.8;9.4	0.9;0.8;9.4	0.9;0.8;9.4
CH	1.9;1.9;70	1.9;1.9;70	1.9;1.9;70	1.9;1.9;70	1.9;1.9;70	1.9;1.9;70	1.9;1.9;70	1.9;1.9;70	1.9;1.9;70	1.9;1.9;70
CZ	0.7;0.7;3.7	0.7;0.7;3.7	0.7;0.7;3.7	0.7;0.7;3.7	0.7;0.7;3.7	0.7;0.7;3.7	0.7;0.7;3.7	0.7;0.7;3.7	0.7;0.7;3.7	0.7;0.7;3.7
DE	6.4;6.6;242.2	6.4;6.6;242.2	6.4;6.6;242.2	6.4;6.6;242.2	6.6;6.8;242.2	6.8;6.9;242.2	7;7.1;242.2	7.2;7.3;242.2	7.4;7.4;242.2	7.4;7.4;242.2
DK	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
EE	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
ES	4.1;3.9;99	4.1;3.9;99	4.1;3.9;99	4.1;3.9;99	4.7;4.5;99	5.2;5;99	5.8;5.6;99	6.3;6.1;99	6.9;6.7;99	6.9;6.7;99
FI	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
FR	2;2;10	2;2;10	2;2;10	2;2;10	2;2;10	2;2;10	2;2;10	2;2;10	2;2;10	2;2;10
GB	2.7;2.7;26.4	2.7;2.7;26.4	2.7;2.7;26.4	2.7;2.7;26.4	2.8;2.7;26.4	2.8;2.7;26.4	2.9;2.7;26.4	2.9;2.7;26.4	3;2.7;26.4	3;2.7;26.4
GR	0;0;0	0;0;0	0;0;0	0;0;0	0.1;0.1;0	0.3;0.3;0	0.4;0.4;0	0.5;0.6;0	0.7;0.7;0	0.7;0.7;0
HR	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
HU	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
SEM	4.2;4.3;46	4.2;4.3;46	4.2;4.3;46	4.2;4.3;46	4.9;4.9;50.9	5.5;5.5;55.8	6.1;6.1;60.6	6.7;6.8;65.5	7.3;7.4;70.4	7.3;7.4;70.4
IT	0.8;0.7;10.6	0.8;0.7;10.6	0.8;0.7;10.6	0.8;0.7;10.6	0.8;0.8;10.6	0.9;0.8;10.6	0.9;0.8;10.6	0.9;0.9;10.6	0.9;0.9;10.6	0.9;0.9;10.6
LT	1.3;1;5	1.3;1;5	1.3;1;5	1.3;1;5	1.3;1;5	1.3;1;5	1.3;1;5	1.3;1;5	1.3;1;5	1.3;1;5
LU	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
LV	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
NL	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
NO	1.3;1.5;6.3	1.3;1.5;6.3	1.3;1.5;6.3	1.3;1.5;6.3	1.3;1.5;6.3	1.3;1.5;6.3	1.3;1.5;6.3	1.3;1.5;6.3	1.3;1.5;6.3	1.3;1.5;6.3
PL	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
PT	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
RO	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0	0;0;0
SI	0.3;0.3;1.7	0.3;0.3;1.7	0.3;0.3;1.7	0.3;0.3;1.7	0.3;0.3;1.7	0.3;0.3;1.7	0.3;0.3;1.7	0.3;0.3;1.7	0.3;0.3;1.7	0.3;0.3;1.7
SK	0.2;0.2;2.6	0.2;0.2;2.6	0.2;0.2;2.6	0.2;0.2;2.6	0.2;0.2;2.6	0.2;0.2;2.6	0.2;0.2;2.6	0.2;0.2;2.6	0.2;0.2;2.6	0.2;0.2;2.6
SE	0.6;0.6;4.1	0.6;0.6;4.1	0.6;0.6;4.1	0.6;0.6;4.1	0.6;0.6;4.1	0.6;0.6;4.1	0.6;0.6;4.1	0.6;0.6;4.1	0.6;0.6;4.1	0.6;0.6;4.1

Notes: the first number is turbining capacity (MW); the second number is pumping capacity (MW); the third number is storage capacity (TWh); if there are no values, that means "0" capacity.

A.5.5 VRE and exogenous generation capacity factors

Based on our climate scenarios, VRE (wind, solar PV and CSP, hydro inflows) hourly profiles are sampled from PECD. According to ERAA[11], planned and unplanned outages for VRE are already included in the hourly time series and are therefore not explicitly modelled.

On top of the VRE, we also model nuclear, biomass and other RES and non-RES generation exogenously, i.e., by assuming they are must-run technologies in line with their historic hourly availability, which we obtained from ENTSO-E TP by averaging their hourly capacity factors for years 2016-2021. These average availability profiles were applied to other RES and non-RES generations. These technologies are generally less flexible due to technical reasons (low ramp rates and longer commitment times) or economic reasons (such as subsidies), making them run less flexibly and not responsive to wholesale price signals.

A.5.6 Net transfer capacity between markets

We assume \$0.01/MWh-e of flow between the market areas we model to avoid indeterminacy when two neighbouring zones have units at the margin and the same marginal cost values. Net transfer capacity was taken from the PECD/ERAA 2021 dataset. The dataset only has 2025 and 20230. We use 2021[12] (historic year) and 2025 to interpolate and calculate the NTC values for 2022-2024, while for 2026-2029, we use ERAA 2025 and 2030 NTC values. NTC for 2031 is equal to 2030 values.

A.5.7 Fuel, carbon and electricity system cost parameters

Table A. 10 reports assumptions for fuel and carbon costs. Fuel and carbon costs are based on the most recent (at the time of writing) forward prices. Note that gas price is not used in the model as it is an endogenous outcome from the model (global gas supply optimisation is subject to constraints in gas and electricity markets).

Table A. 10: Fuel (\$2021/MWh) and carbon (\$2021/tCO_{2e}) price assumptions

	2023	2024	2025	2026	2027	2028	2029	2030	2031
Nuclear	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13	2.13
Crude Oil	49.9	47.3	45.1	43.3	41.9	40.8	40.2	40.1	40.1
Steam coal*	16	17	16	15	14	13	12	10	10
CO_2 Price (EU ETS)	119	119	124	131	136	141	146	146	146

Source: Nuclear fuel cost from ERAA 2021 study; Coal, crude oil, and carbon prices are (most recent) forward prices from Eikon and Bloomberg terminal; * forward coal price if the coal price delivered into Northwest Europ; crude oil forward price is taken on Feb 27 2023.

We apply a discount or markup above the European forward coal prices to calculate imported coal prices for Japan and China. These markups are based on the spot prices for coal (2011-2021) reported by BP (2022). Thus, Japan's spot steam coal has an average markup of 17%, whereas China's spot price has a markup of 22% (average in 2011-2021) above the expected European forward price reported in Table A. 10.

As for major net exporters of steam coal, we computed the supply cost of coal supplies based on the IEA WEO 2020 data. The best-fit regressions are reported in Table A. 11 below. Note that coal prices and, hence, the cost of coal-based power generation are treated endogenously in the model.

[11] page 12 of ERAA methodology paper (ENTSO-e, 2021)

[12] Because ENTSOE-E TP do not report actual NTC for 2021 we average 50 hours with highest flows and take these values as 2021 NTC for further calculations.

Table A. 11: Supply cost curves for thermal coal

	Slope	Intercept	R^2	Unit of measurement: Commodity price	Unit of measurement: Commodity demand
Steam coal: North America	0.17200	4.92733	0.61	$2021/MWh	TWh/day
Steam coal: Central & South America	4.19314	2.44764	0.75	$2021/MWh	TWh/day
Steam coal: Africa & Middle East	1.18445	6.30152	0.69	$2021/MWh	TWh/day
Steam coal: Russia	0.60077	6.52922	0.36	$2021/MWh	TWh/day
Steam coal: Asia Pacific	0.28916	8.37027	0.66	$2021/MWh	TWh/day

Source: IEA (2020)

We use a wholesale electricity price cap of €15,000/MWh-e, a default assumption in the ERAA 2021 study (ENTSO-e, 2021), to ensure the wholesale electricity market clears under shortage conditions.[13]

The carbon price reported in Table A. 10 applies only to the EU markets. For China and Northeast Asia (Japan, Korea, and Taiwan), we use IEA's (2020) assumptions:

- China carbon price: $17/tCO2 in 2025, reaching $35/tCO2 in 2040
- Japan, Korea and Taiwan carbon price: $34/tCO2 in 2025, reaching $52/tCO2 in 2040

A.6 Gas market modelling data & assumptions

A.6.1 Natural gas demand in Europe

For European countries in the model, we consider the following gas demand sectors:

- Gas demand in residential (RES) buildings is split into gas demand for space heating (temperature dependent) and gas demand for all other purposes (assumed flat across the year);
- Gas demand in commercial (COM) buildings is split into gas demand for space heating (temperature dependent) and gas demand for other purposes (assumed flat);
- Gas demand in industry and road transport[14] (IND); industrial gas demand also includes non-energy use gas demand (i.e., gas as feedstock).
- Gas demand in the electricity generation sector (PWR) is modelled **endogenously** by coupling gas and electricity markets via gas-fired electricity generation capacity (see §A.4.).

Temperature-sensitive gas demand, especially for household space heating, is the most critical demand category (which falls under the definition of protected customers, especially residential heat demand[15]); we developed a method to model it explicitly (see Ah-Voun et al., 2024).

As for industrial gas demand profiles, we rely on a dataset from Zhou et al. (2022). The dataset contains daily industrial gas demand for EU27+UK for 2016-2022. We use the dataset to create daily profiles by averaging the authors' simulated daily industrial demand.

[13] However, worth noting that the current wholesale electricity price cap (day-ahead) in most EU MS is €3,000/MWh-e. For details, see: https://ec.europa.eu/energy/sites/ener/files/documents/swd_2016_385_f1_other_staff_working_paper_en_v3_p1_870001.pdf
[14] Without loss of insights, we aggregated road transport gas demand with industrial gas demand sector as the former is small
[15] https://ec.europa.eu/commission/presscorner/detail/sv/MEMO_16_308

Lastly, the energy sector's own use gas represents ca. 4.5% of total gas demand, according to Eurostat gas consumption data for 2019. We consider this demand by assuming a 4.5% uplift of the estimated gas consumption in the residential, commercial, and industrial sectors.

For Ukraine, in line with the current electricity consumption trend, we assume that final gas demand will be 40% lower than the pre-war consumption level (2019) for the entire modelled period (2022-2031). Thus, the gas demand for space heating in Ukraine was scaled down by 40% along with the final demand. For Norway and Switzerland, we assume no growth in final gas demand.

Table A. 12: Projected gas demand (bcm) by sectors in Europe under normal CY

	2023	2024	2025	2026	2027	2028	2029	2030	2031
AT_(COM)	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
AT_(IND)	3.2	3.1	3.0	2.9	2.9	2.8	2.7	2.6	2.7
AT_(RES)	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.8	1.8
BE_(COM)	1.9	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
BE_(IND)	4.7	4.6	4.5	4.5	4.5	4.5	4.5	4.5	4.6
BE_(RES)	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.0
BG_(COM)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
BG_(IND)	1.9	2.2	2.4	2.2	2.1	1.9	1.8	1.7	1.7
BG_(RES)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
CH_(COM)	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
CH_(IND)	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3
CH_(RES)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
CZ_(COM)	1.2	1.2	1.2	1.2	1.2	1.3	1.3	1.3	1.2
CZ_(IND)	2.7	2.8	2.8	2.8	2.9	3.0	3.0	3.1	3.0
CZ_(RES)	2.0	2.0	2.0	2.0	2.1	2.1	2.1	2.1	2.0
DE_(COM)	9.4	9.3	9.2	9.2	9.2	9.2	9.2	9.3	9.3
DE_(IND)	22.3	21.4	20.7	20.8	21.0	21.1	21.3	21.4	21.9
DE_(RES)	23.8	23.6	23.4	23.4	23.5	23.5	23.5	23.6	23.7
DK_(COM)	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2

DK_(IND)	0.8	0.8	0.7	0.7	0.7	0.7	0.6	0.6	0.6
DK_(RES)	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
EE_(COM)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
EE_(IND)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
EE_(RES)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
ES_(COM)	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
ES_(IND)	11.1	11.3	11.5	11.3	11.1	10.8	10.6	10.4	10.2
ES_(RES)	3.3	3.3	3.3	3.3	3.3	3.2	3.2	3.2	3.2
FI_(COM)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FI_(IND)	0.9	0.9	1.0	1.0	1.0	0.9	0.9	0.9	1.0
FI_(RES)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FR_(COM)	6.7	6.7	6.7	6.6	6.6	6.6	6.6	6.6	6.5
FR_(IND)	11.8	11.4	11.1	10.9	10.7	10.6	10.4	10.2	10.9
FR_(RES)	14.4	14.4	14.3	14.2	14.2	14.1	14.1	14.0	14.0
GB_(COM)	7.8	7.8	7.8	7.8	7.8	7.7	7.7	7.7	7.7
GB_(IND)	9.5	9.6	9.7	9.5	9.3	9.1	8.9	8.8	8.8
GB_(RES)	26.0	26.1	26.1	26.0	25.9	25.7	25.6	25.5	25.7
GR_(COM)	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.2
GR_(IND)	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
GR_(RES)	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
HR_(COM)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
HR_(IND)	0.6	0.6	0.7	0.7	0.6	0.6	0.6	0.6	0.6
HR_(RES)	0.5	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5

HU_(COM)	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
HU_(IND)	1.9	1.9	2.0	1.9	1.8	1.8	1.7	1.6	1.7
HU_(RES)	3.6	3.7	3.7	3.6	3.6	3.6	3.5	3.5	3.5
IT_(COM)	8.0	8.0	8.0	8.0	7.9	7.9	7.9	7.9	7.7
IT_(IND)	11.9	11.9	11.9	11.8	11.6	11.5	11.4	11.3	11.6
IT_(RES)	19.9	19.9	19.9	19.8	19.7	19.7	19.6	19.6	19.1
LT_(COM)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
LT_(IND)	0.6	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
LT_(RES)	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
LU_(COM)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
LU_(IND)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
LU_(RES)	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
LV_(COM)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
LV_(IND)	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
LV_(RES)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
NL_(COM)	3.1	3.1	3.2	3.1	3.1	3.1	3.1	3.1	3.3
NL_(IND)	6.4	6.5	6.7	6.6	6.5	6.4	6.3	6.2	6.4
NL_(RES)	8.3	8.4	8.5	8.4	8.4	8.4	8.3	8.3	8.8
NO_(COM)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NO_(IND)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
NO_(RES)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PL_(COM)	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	1.5
PL_(IND)	6.0	6.4	6.8	7.3	7.8	8.3	8.7	9.2	9.5

PL_(RES)	3.6	3.7	3.8	3.9	4.0	4.1	4.3	4.4	4.3
PT_(COM)	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
PT_(IND)	2.1	2.4	2.6	2.6	2.7	2.7	2.7	2.7	2.8
PT_(RES)	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
RO_(COM)	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
RO_(IND)	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9
RO_(RES)	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
SE_(COM)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
SE_(IND)	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.9	0.9
SE_(RES)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SEM_(COM)	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
SEM_(IND)	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
SEM_(RES)	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
SI_(COM)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SI_(IND)	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7
SI_(RES)	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
SK_(COM)	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
SK_(IND)	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3	1.3
SK_(RES)	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
UA_(COM)	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
UA_(IND)	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
UA_(RES)	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8

Notes: RES – residential demand; COM – commercial demand; IND – industrial, transport and other demand

A.6.2 Natural gas demand for non-European countries

A.6.2.1 Annual demand projection

For non-European gas demand projections, we use IEA's recent short-term gas market forecast to 2025 (IEA, 2022b), and for 2025-2030, we use IEA's World Energy Outlook (2020) projections. In particular, we use WEO's (2020) *Stated Policy Scenario* (SPS) as our baseline for the demand projections covering 2025-2030. The SPS is a more granular scenario that examines policies in place sector-by-sector compared to other WEO scenarios. The 2020 WEO edition is chosen because this is the last edition in which IEA published detailed datasets (free of charge) for these scenarios.

Table A. 13: Projected gas demand (bcm) for non-Europe countries

	2023	2024	2025	2026	2027	2028	2029	2030	2031
Belarus	19.9	19.9	19.9	20.1	20.3	20.5	20.7	20.9	20.9
Moldova	3.3	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.4
Russia (non-power)*	319.9	318.0	311.5	308.5	305.6	302.1	294.5	291.8	299.0
Australia	42.9	44.1	45.3	46.5	47.7	48.9	50.0	51.1	51.3
Balkans	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.5	3.5
Central Asia	97.9	97.8	97.8	98.8	99.8	100.7	101.7	102.5	102.5
China (non-power)*	331.8	346.6	357.3	365.5	369.9	377.9	382.0	389.7	392.3
Algeria	49.5	50.2	50.9	51.1	51.3	51.4	51.6	51.7	51.5
Israel	11.0	11.3	11.6	11.6	11.7	11.7	11.7	11.8	11.7
India (non-power)*	53.8	55.9	58.4	65.1	71.2	77.5	84.0	90.0	90.3
Japan, Korea and Taiwan (non-power)*	77.9	78.0	79.7	81.4	83.2	84.9	86.6	88.2	88.1
Middle East (non-power)**	389.3	405.5	420.4	421.0	416.0	411.7	412.2	407.6	405.0
North America (non-power)*	705.0	710.1	710.1	665.4	631.3	597.1	556.1	527.8	520.8
Pakistan	43.6	44.7	45.9	47.2	48.6	49.9	51.3	52.6	52.6
Southeast Asia (non-power)*	108.9	109.7	112.5	116.0	121.6	127.2	130.8	136.2	135.7
South Caucasus	18.3	18.3	18.3	18.5	18.7	18.9	19.0	19.2	20.7
Central and South America (non-power)*	103.8	105.3	106.5	104.9	103.3	103.1	101.6	101.4	101.0
Rest of Africa (non-power)*	63.7	71.5	79.2	79.4	79.6	78.5	78.7	78.9	78.9
Turkey	59.6	59.5	59.5	60.1	60.7	61.3	61.9	62.4	62.4

Notes: * for these regions and countries, demand projection excludes power sector gas demand potential, which is modelled endogenously; SEM – Republic of Ireland and Northern Ireland.

Note that for key regions and countries outside Europe, gas demand in the power sector is modelled endogenously (considering optimal dispatch of gas, oil and coal-fired generation, see A.6.1.3.3). The following non-European power markets are considered explicitly in the model: China, India, Japan, South Korea, Taiwan, Middle East, North America, Africa, Central and South America, Russia, and South East Asia. We model two separate gas demand nodes for these regions and countries – gas demand in the power sector and gas demand in all other sectors.

IEA only publishes detailed power generation and capacity projections for Japan. To calculate projections of power generation and capacity for South Korea and Taiwan, we assume that coal, oil and natural gas capacity, generation, and utilisation rates follow Japan's projections (trend) as per IEA.

A.6.2.2 Demand profiles

To calculate daily gas demand profiles (i.e., percentage of daily gas demand in annual total demand) for non-European countries and regions in the gas model, we rely mainly on two data sources[16]: (1) the JODI World Gas Database,[17] (2) and IEA Monthly Gas Statistics[18]. These datasets contain monthly gas consumption. Thus, we do not consider daily variation for countries outside Europe; this remains an area for future improvements to our dataset.

A.6.2.3 Inter-fuel competition in the power sector of key non-European regions

We consider switching to and from natural gas-fired generation in the power sector of non-European markets and regions similarly to the detailed electricity market modelling outlined in Section A.5. The only difference is that we consider competition between coal, gas and oil-fired generation and do not capture the entire load and other generation sources like wind, solar, bioenergy, nuclear etc. This is an area we leave for future research.

To be consistent with the IEA projections, we take total annual electricity generation (see Table A. 14) from coal, oil and gas and use the demand profiles (see A.6.1.3.2) to calculate hourly average electricity demand for these three fossil fuel sources. These hourly "residual"[19] demand time series are then used in the model, and the projected installed capacity of the three generation technologies is used to endogenously determine competition between the three fuels and, hence, endogenous gas demand in the power sector. The upper bound of fuel supply for power generation was applied for selected regions outside Europe (see Table A. 15) to calibrate the results to IEA's projections further. While the upper bound ensures results are consistent with the baseline (no supply-demand shocks) scenario, we allowed the model to violate these upper bounds with the following penalty costs, which were calibrated to historic fuel prices:

- coal: $25/MWh-th, equivalent to the yearly average steam coal price observed in 2022;
- oil: $63/MWh-th, equivalent to a crude oil price of $100/boe;
- gas: $239/MWh-th, equivalent to a spot gas price of $70/MMBtu.

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[16] Pakistan monthly gas consumption profile is calculated using monthly LNG imports for the years 2019-2021 and adding a constant indigenous production (flat profile) to arrive at total implied monthly demand.
[17] https://www.jodidata.org/gas/
[18] https://www.iea.org/data-and-statistics/data-product/monthly-gas-statistics
[19] "residual" in the sense that we only take gas, coal and oil generation and not full load and other generation sources to endogenously optimize electricity dispatch.

Table A. 14: Projected electricity generation (TWh) and capacity (GW)

		Electricity generation			Electricity generation capacity		
		2019	**2025**	**2030**	**2019**	**2025**	**2030**
China	Bioenergy	128	229	289	23	41	50
	Coal	4,878	5,179	5,152	1,051	1,132	1,148
	Hydro	1,270	1,297	1,389	356	411	446
	Natural gas	251	402	529	86	120	145
	Nuclear	350	451	648	49	65	93
	Oil	11	7	5	8	8	8
	Other renewables	632	1,325	1,940	416	789	1,147
India	Bioenergy	42	67	77	12	13	15
	Coal	1,135	1,206	1,343	235	269	269
	Hydro	175	177	226	49	60	76
	Natural gas	71	94	108	28	30	30
	Nuclear	40	66	109	7	9	16
	Oil	5	7	7	8	8	8
	Other renewables	115	279	590	75	174	345
Japan	Bioenergy	52	55	61	9	11	12
	Coal	323	290	239	51	50	41
	Hydro	80	90	92	50	51	51
	Natural gas	346	280	238	84	79	77
	Nuclear	86	120	210	33	34	30
	Oil	35	32	18	35	20	12
	Other renewables	74	110	125	68	100	116
Russia	Bioenergy	3	4	9	2	2	3
	Coal	173	150	136	51	42	33
	Hydro	190	196	208	54	56	59
	Natural gas	550	601	601	128	139	138
	Nuclear	200	203	219	30	30	32
	Oil	12	5	4	4	2	2
	Other renewables	2	8	28	1	4	12
Southeast Asia	Bioenergy	35	31	45	8	10	12
	Coal	510	588	700	81	106	123
	Hydro	195	180	245	47	56	77

	Natural gas	383	524	581	98	123	142
	Nuclear	-	-	-	-	-	-
	Oil	19	18	18	25	22	21
	Other renewables	41	91	152	18	46	76
Africa	Bioenergy	2	5	19	1	2	5
	Coal	259	265	256	50	51	48
	Hydro	141	183	221	36	44	51
	Natural gas	332	345	386	110	123	132
	Nuclear	12	14	28	2	2	4
	Oil	72	71	65	43	35	35
	Other renewables	33	87	219	13	38	94
Central and South America	Bioenergy	72	91	98	20	23	24
	Coal	68	43	37	14	14	12
	Hydro	723	801	892	186	195	210
	Natural gas	249	232	254	70	72	84
	Nuclear	23	25	36	4	3	5
	Oil	99	91	79	49	43	37
	Other renewables	100	194	273	34	83	116
Middle East	Bioenergy	0	2	7	0	0	1
	Coal	1	11	14	0	3	3
	Hydro	19	24	27	17	17	19
	Natural gas	819	846	1,004	224	267	302
	Nuclear	8	41	49	1	7	9
	Oil	307	310	272	96	95	83
	Other renewables	9	43	107	5	21	50
North America	Bioenergy	88	102	111	22	23	25
	Coal	1,152	677	501	266	163	111
	Hydro	688	763	788	196	200	204
	Natural gas	1,922	2,207	2,250	554	593	649
	Nuclear	962	867	812	120	111	104
	Oil	81	34	21	79	47	34
	Other renewables	490	844	1,154	214	364	498

Source: IEA WEO (2020)

Table A. 15: Power generation fuel supply upper bound (TWh-th/day)

Commodity	Region	2022	2025	2030	2031
Coal	China	41.1	39.4	39.0	39.0
Oil	China	0.1	0.2	0.2	0.2
Coal	India	9.7	9.1	10.1	10.1
Oil	India	0.0	0.1	0.1	0.1
Coal	Southeast Asia	4.2	4.4	5.1	5.1
Gas	Southeast Asia	3.0	3.1	3.5	3.5
Oil	Southeast Asia	0.2	0.2	0.2	0.2
Coal	Africa	2.1	2.1	2.0	2.0
Gas	Africa	1.7	1.8	2.2	2.3
Oil	Africa	0.6	0.5	0.5	0.5
Coal	Rest of America	0.4	0.3	0.3	0.3
Gas	Rest of America	1.6	1.8	2.3	2.4
Oil	Rest of America	0.7	0.7	0.6	0.6
Coal	Middle East	0.0	0.1	0.1	0.1
Gas	Middle East	5.9	6.6	8.9	9.4
Oil	Middle East	2.3	2.3	2.0	2.0
Coal	North America	6.7	4.9	3.5	3.5
Oil	North America	0.4	0.2	0.1	0.1
Gas	Japan, Korea, Taiwan	3.3	3.4	3.7	3.7
Coal	Japan, Korea, Taiwan	4.2	4.1	3.4	3.4
Oil	Japan, Korea, Taiwan	0.3	0.2	0.1	0.1

Source: own calculations based on IEA WEO (2020), BP Statistical Review of World Energy (BP, 2022)

A.6.3 Natural gas demand-side response in Europe

A.6.3.1 Industrial gas demand-side response

Industrial demand side response is divided into production curtailment and fuel switching. We discuss the production curtailment first and then fuel switching.

We use a detailed dataset of industrial energy consumption structure taken from the IDEES Database[20] to calculate the cost and capacity of industrial production curtailment. Industry subsectors that we consider for the EU27 and the UK are outlined in Table A. 16. The database reports production capacity, historical output of final products, energy consumption structure and gross value added (GVA) for each of the industrial sectors outlined in the table below. The dataset covers 2000-2015; thus, we calculate the average of these time series. First, we divide the gross value added by natural gas consumption to calculate the unit cost ($/mmBtu of natural gas) of demand response (eq. A1).

[20] https://data.jrc.ec.europa.eu/dataset/jrc-10110-10001

$$Cost_{IC_{DSR}i} = \frac{GVA_i}{Q_i} \times \frac{Q_i}{C_i} \qquad \text{(A1)}$$

where GVA_i is the gross value added of industry i, Q_i is final industrial output, C_i is natural gas consumption.

Strictly speaking, the cost of demand response should also include the price of gas at which industrial consumers agreed to pay for the resource. Since our primary objective is to use the computed cost of industrial demand response as an allocation mechanism during a shortage period, the purchase price should not matter, as in Europe, wholesale gas markets are well integrated. Therefore, only industry- and country-specific GVAs will influence this allocation.

The volume of demand side response from production curtailment is calculated using the capacity utilisation rate (UR_i) in 2015, the industry's installed capacity ($\overline{Q_i}$), and gas consumption per unit of output ($\frac{Q_i}{C_i}$) as follows:

$$Volume_{IC_{DSR}i} = UR_i \times \overline{Q_i} \times \frac{C_i}{Q_i} \qquad \text{(A2)}$$

The parameters for utilisation rate and installed capacity were taken from the database for 2015 (the latest available), while gas consumption per unit of output is an average of 2000-2015.

Table A. 16: Industries considered for calculations of demand response capacity and associated cost

Industry Code	Comment	Sub Industry code	Comment
ISI	Iron and steel	ISI_ElecArc	Electric Arc
NFM	Non-Ferrous Metals	ISI_IntSteelWorks	Integrate Steelworks
CHI	Chemicals Industry	CHI_Basic	Basic chemicals
NMM	Non-metallic mineral products	CHI_Other	Other chemicals
PPA	Pulp, paper and printing	CHI_Pharma	Pharmaceutical products
FBT	Food, beverages and tobacco	NFM_Alumina	Alumina production
TRE	Transport Equipment	NFM_ AluminumPrim	Aluminium primary production
MAE	Machinery Equipment	NFM_ AluminumSecond	Aluminium secondary production
TEL	Textiles and leather	NFM_Other	Other non-ferrous
WWP	Wood and wood products	NMM_Cement	Cement
OIS	Other Industrial Sectors	NMM_Ceramic	Ceramics and other
		NMM_Glass	Glass production
		PPA_Paper	Paper production
		PPA_PrintingMedia	Printing and media reproduction
		PPA_Pulp	pulp production

In line with the IEA's (2023) findings, we assume that the maximum fuel switching in the industrial sector is seven bcm, which we assume will be triggered at a price above \$16/MMBtu (annual average 2022 gas price) (see Ruhnau et al., 2023; Moll et al., 2023; Chiacchio et al., 2023).

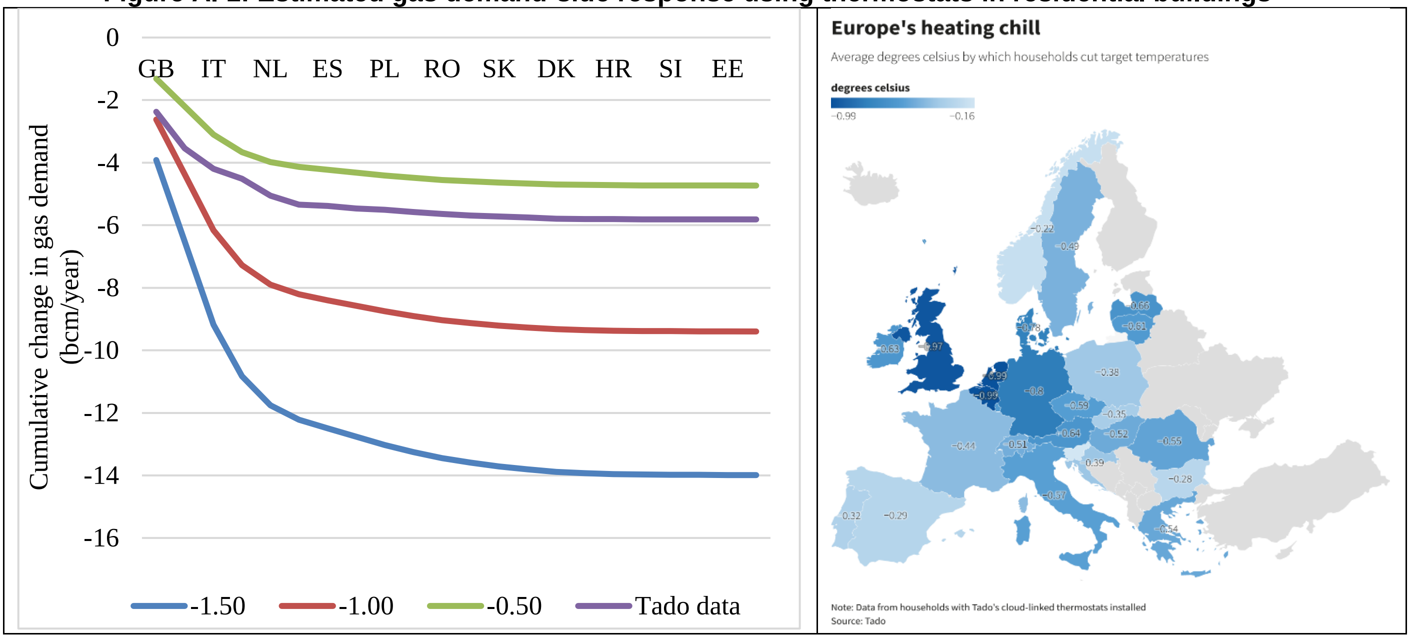
A.6.3.2 Residential gas demand-side response

We developed a Heating Degree Model (HHD) (for details, see Ah-Voun et al., 2024) to measure the impact of adjusting home thermostats on European residential gas demand (see Figure A. 1 left panel for estimations and right panel for some measured actual behavioural response to the 2022/23 crisis).

In particular, for every half-degree downward adjustment of home thermostats (relative to reference points, which is national specific; see Ah-Voun et al., 2024 for details), ca. 4.7 bcm of gas demand is saved, with GB, Germany, Italy, France, the Netherlands and Belgium providing a total of 87% of that total response. The Tado data (right panel, Figure A. 1) suggest that around 5.81 bcm was saved in 2022 due to households' varying responses using thermostats. IEA (2023[21]) analysis suggests that European households' behavioural response totalled seven bcm, predominantly by adjusting home thermostats downwards by an average of 0.6 °C and some limited fuel-switching.

While some empirical studies have emerged recently (see, e.g., Huebner, 2023[22] study evidencing that British household adjusted their thermostat downwards by one °C during the 2022/23 energy crisis), evidence is still limited on the extent of thermostat adjustment by the whole population in Europe (those with gas boilers) and the extent of fuel switching. Thus, to be consistent with IEA's empirical findings, we allow for a maximum of seven bcm of the European residential sector. This maximum residential gas demand response equals a downward change in home thermostats between 0.6-0.7 °C. Based on growing empirical evidence from the 2022/23 energy crisis (Ruhnau et al., 2023; Moll et al., 2023; Chiacchio et al., 2023; Sperber et al., 2024; Zapata-Webborn, et al., 2024), we assume that residential demand response will only be triggered when prices exceed $17.6/MMBtu, which is 10% higher than the assumed trigger price for the industrial fuel switching to reflect that it is costlier for residential consumers to change their behaviour. Figure A. 2 shows an example of the total potential gas demand-side response and associated costs for Germany.

Figure A. 1: Estimated gas demand-side response using thermostats in residential buildings

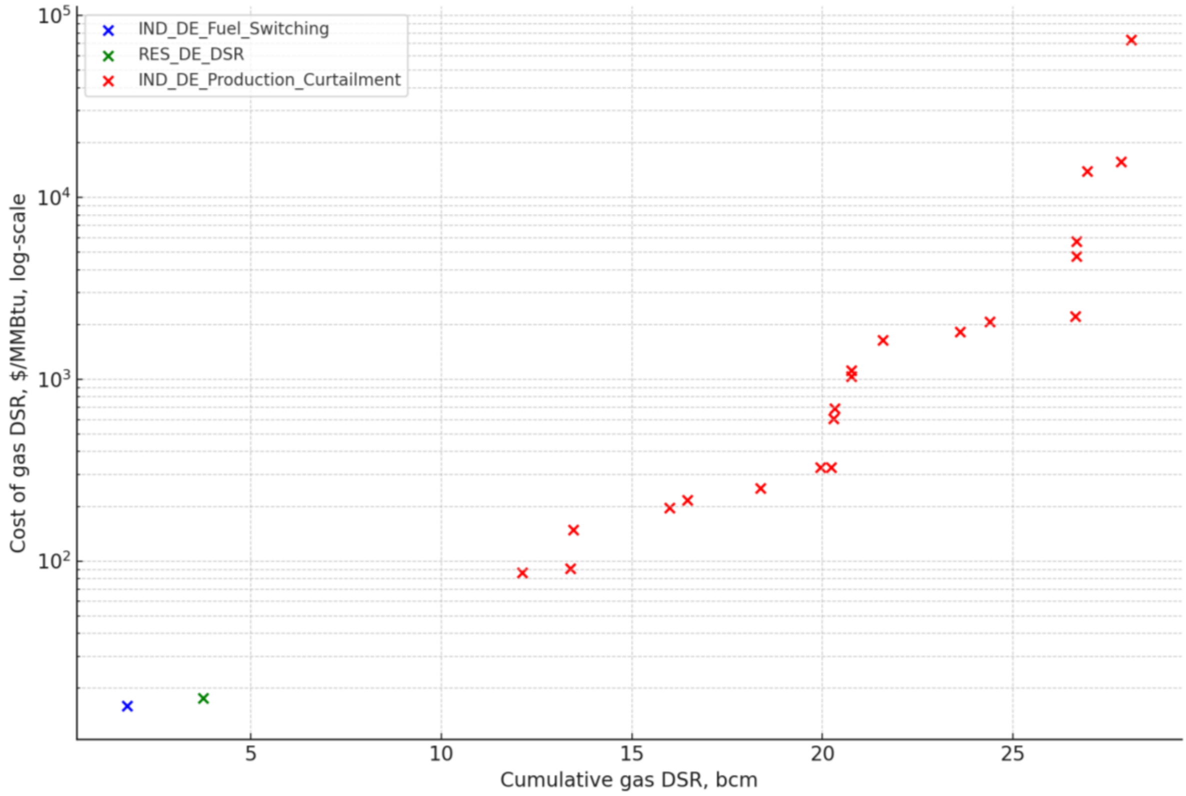


Source: The left panel uses the HDD model from Au-Voun et al. (2024); the right-hand panel was taken from https://www.reuters.com/business/energy/europeans-dial-down-heating-heed-calls-save-energy-2023-01-18/

[21] https://www.iea.org/commentaries/europe-s-energy-crisis-what-factors-drove-the-record-fall-in-natural-gas-demand-in-2022

[22] Huebner, G. M., Hanmer, C., Zapata-Webborn, E., Pullinger, M., McKenna, E. J., Few, J., ... & Oreszczyn, T. (2023). Self-reported energy use behaviour changed significantly during the cost-of-living crisis in winter 2022/23: insights from cross-sectional and longitudinal surveys in Great Britain. *Scientific Reports*, *13*(1), 21683.

Figure A. 2: An example of the gas demand-side response curve for Germany



A.6.4 Natural gas supply

We use the average (2011-2021) actual growth rate in production for countries and regions in the model from the BP Statistical Review of World Energy (BP, 2022) and apply this average growth rate to project production profiles until 2031. The outlook for production from the UK is based on National Grid ESO *Future Energy Scenarios (2022).* The production outlook for the Netherlands includes a policy decision to shut down the Groningen field by 2023. Table A. 17 summarises the projected production by regions considered in the modelling.

Table A. 17: Projection of gas production capacity (bcm/year) by regions in the model

	2023	2024	2025	2026	2027	2028	2029	2030	2031
Algeria	101.60	104.03	106.51	109.05	111.66	114.32	117.05	119.84	122.70
Denmark	1.08	0.97	0.88	0.80	0.73	0.66	0.60	0.54	0.49
Germany	3.73	3.38	3.06	2.78	2.52	2.28	2.07	1.88	1.70
Austria	0.76	0.69	0.63	0.57	0.52	0.47	0.42	0.38	0.35
Hungary	1.39	1.26	1.15	1.04	0.94	0.85	0.77	0.70	0.64
Poland	3.18	2.88	2.61	2.37	2.15	1.95	1.77	1.60	1.45
Romania	6.96	6.31	5.72	5.18	4.70	4.26	3.86	3.50	3.17
Italy	2.62	2.37	2.15	1.95	1.77	1.60	1.45	1.32	1.19
Czech Republic	0.16	0.15	0.13	0.12	0.11	0.10	0.09	0.08	0.07
France	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00

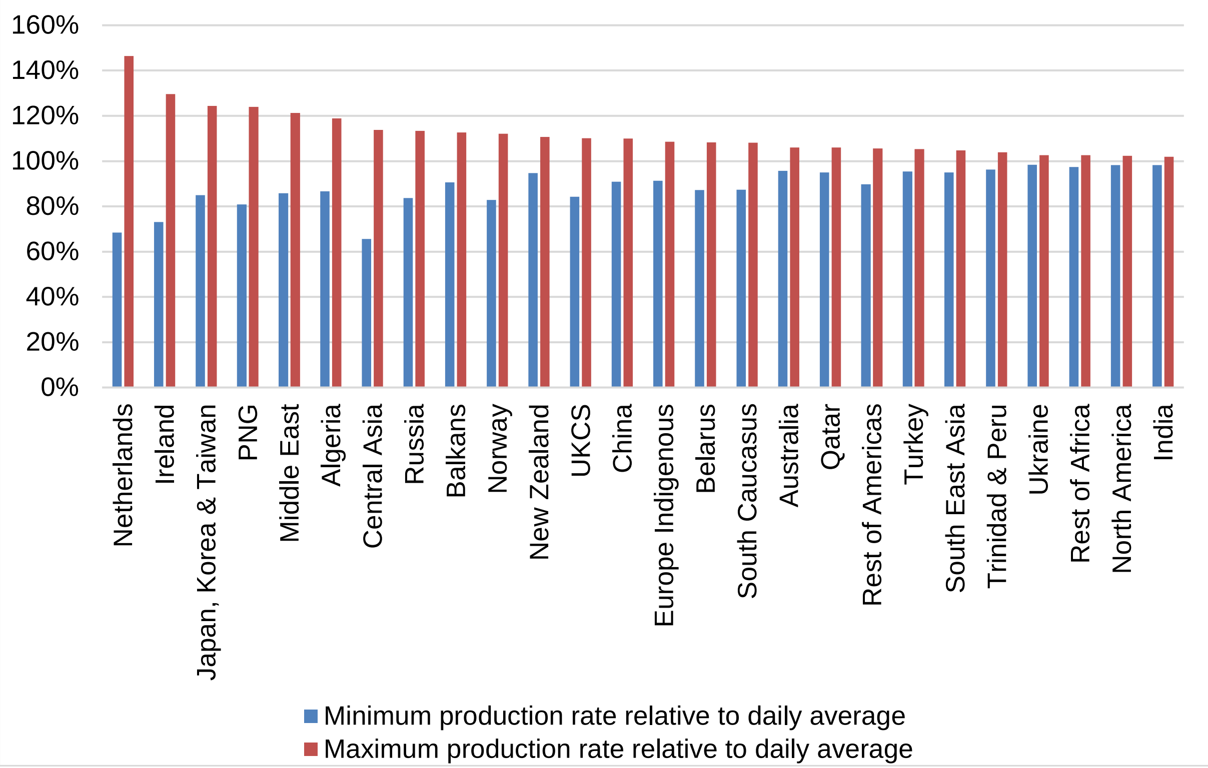
Greece	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00
Slovakia	0.07	0.06	0.06	0.05	0.05	0.04	0.04	0.03	0.03
Slovenia	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Bulgaria	0.06	0.05	0.05	0.04	0.04	0.04	0.03	0.03	0.03
Croatia	0.91	0.82	0.75	0.68	0.61	0.56	0.50	0.46	0.41
Spain	0.06	0.06	0.05	0.05	0.04	0.04	0.04	0.03	0.03
Central Asia	177.96	180.78	183.65	186.56	189.51	192.52	195.57	198.67	201.82
Southeast Asia	252.45	253.00	253.55	254.11	254.66	255.22	255.77	256.33	256.89
Australia	180.11	180.11	180.11	180.11	180.11	180.11	180.11	180.11	180.11
Trinidad and Peru	34.07	33.06	32.07	31.11	30.18	29.28	28.40	27.55	26.73
Middle East*	586.52	612.46	639.56	667.85	697.40	728.25	760.47	794.11	829.25
Qatar	213.95	217.47	221.04	224.67	228.37	232.12	235.94	239.81	243.76
Africa**	165.55	170.13	174.84	179.68	184.65	189.77	195.02	200.42	205.96
South Caucasus	36.50	39.11	41.89	44.88	48.08	51.51	55.18	59.11	63.33
Russia Ural region	619.76	613.44	600.92	598.89	591.03	595.27	606.37	611.53	619.20
Russia Volga region	26.92	25.49	23.22	21.70	19.80	17.88	16.81	15.53	15.71
Russia Siberia region	39.38	57.23	82.34	96.00	116.60	123.93	125.20	129.56	132.34
Russia Far East region	33.94	33.16	32.31	31.79	30.63	30.82	29.48	31.34	30.92
Norway	126.96	126.96	126.96	126.96	126.96	126.96	126.96	126.96	126.96
Netherlands	16.14	13.37	13.12	13.78	13.29	13.23	13.78	13.24	13.36
North America	1,299.31	1,342.25	1,386.60	1,432.43	1,479.76	1,528.66	1,579.18	1,631.36	1,685.27
Great Britain (UKCS)	38.12	34.89	31.93	30.23	27.85	23.91	22.08	19.32	19.32
Great Britain (Onshore)	0.56	0.53	0.50	0.48	0.45	0.43	0.40	0.38	0.38

South and Central America***	118.28	118.85	119.43	120.01	120.59	121.18	121.77	122.36	122.96
China	225.07	240.86	257.77	275.86	295.22	315.95	338.12	361.85	387.25
India	26.30	25.25	24.24	23.27	22.34	21.44	20.58	19.76	18.97
Japan, Korea and Taiwan	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83
Ireland	1.53	1.38	1.24	1.13	1.02	0.94	0.86	0.77	0.77
Balkans	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
Ukraine	18.40	18.30	18.21	18.12	18.03	17.94	17.85	17.76	17.67
Pakistan	32.17	31.92	31.67	31.42	31.18	30.93	30.69	30.45	30.21
Belarus	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Turkey	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44	0.44
Israel	10.36	10.36	10.36	10.36	10.36	10.36	10.36	10.36	10.36
Papua New Guinea	14.11	14.11	14.11	14.11	14.11	14.11	14.11	14.11	14.11

Notes: * excludes Qatar, ** excludes Algeria, *** excludes Trinidad and Peru

We explicitly consider the flexibility of gas production by allowing the daily production rate to ramp up and down within the observed range. We use historic monthly production data from the JODI dataset to calculate daily production ranges (see Figure A. 2). While we allow the production to ramp up and down, we also make sure that the resulting annual production level is in line with the projected values reported in Table A. 17.

Figure A. 2: Historic average gas production ranges



Source: author's calculations based on JODI dataset

Short-run marginal cost (SRMC) of gas production for the key countries and regions in our model is assumed to have the following linear relationship:

$$SRMC_{Prod\,j} = A_j \times q_j + B_j \qquad \text{(A3)}$$

where $SRMC_{Prod\,j}$ is the short-run marginal cost of gas production from j [$2021/tcm]; A_j and B_j are parameters of the linear SRMC curves, while q_j is a decision variable - how much gas to produce [bcm/month]. Estimates of the parameters A and B are reported in Table A. 18.

Table A. 18: Estimates of the short-run marginal cost of gas production

Country/region	**A**	**B**
Algeria	0.000010	+34.0120
North America	0.26704	+46.7837
Russia: Far East	0	+55.6166
Russia: Siberia	1.7323	+53.7563
Russia: Ural	0.9239	-27.6930
Russia: Volga	0	+24.7255
Qatar	0	19.70
Australia	0	120.00
Netherlands	20.2371	+17.6269
China	5.6590	-5.3572
Central Asia	1.5368	+7.9988

Southeast Asia	0	95.68
Trinidad & Peru	0	39.56
Norway	0	113.12
Middle East	0.7429	+18.9497
India	8.4807	+35.5624
Africa	0	189.28
Central & South America	9.1527	-44.3592
South Caucasus	0	39.00
PNG	0	18.03
UKCS	0	253.88
Pakistan	4.0827	-0.3343

Source: The author's calculations are based on sources cited in Chyong and Hobbs (2014), Chyong et al. (2023), and data provided by industry stakeholders.

A.6.5 Natural gas storage

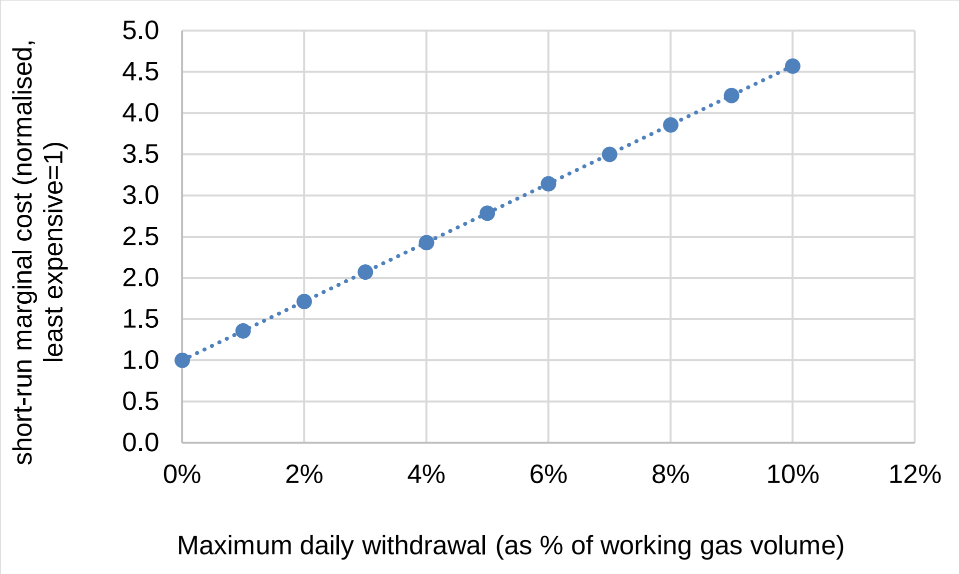
Gas storage capacity is based on datasets from the IEA Natural Gas Information Report (IEA, 2019), the Eikon LNG dataset, and EIA's Field Level Storage data for the USA. We also include a projection of the EU's future gas storage capacity by considering projects that took FID in the 2022 gas TYNDP.

Individual storage facilities were aggregated into a single country-level facility. This aggregation significantly reduces the size of the model because for some markets in Europe – such as Germany, for example – there are 51 storage sites alone (IEA, 2019).[23]

However, modelling storage in aggregation will neglect the different technical characteristics (fast-ramping vs. long-duration storage) of various storage sites and hence their cost structure – fast-ramping storage is, in general, more costly to use than long-duration inter-seasonal storage (EC, 2017, page 70). Thus, the approach we adopt to reflect storage facilities' different withdrawal capacities and their respective cost is to build a 'short-run marginal cost curve' for each market area/country (see Figure A. 3). This marginal cost curve is expressed as a linear (increasing) relationship between maximum daily withdrawal rate and costs. This curve was approximated using the cost data reported in the gas storage report (EC, 2015).

[23] In the USA there are 432 storage sites (EAI, 2022: Field Level Storage data). Available at: https://www.eia.gov/naturalgas/ngqs/#?report=RP7&year1=2020&year2=2020

Figure A. 3: An example of a short-run marginal cost curve showing a positive relationship between withdrawal rate and cost



Source: Calculated from data presented in EC (2017) gas storage study

Thus, mathematically, storage's short-run marginal cost (SRMC) can be expressed as follows:

$$SRMC_{Stor_s} = A_s \times w_s + B_s \qquad \text{(A4)}$$

where $SRMC_{Stor_s}$ is the short-run marginal cost of withdrawing gas from storage facility s [$2021/tcm]; A_s and B_s are parameters of the linear SRMC curves, while w_s is a decision variable - how much gas to withdraw [bcm/month].

One can think of $SRMC_{Stor}$ as a 'bundled' storage fee that European storage operators often quote. This bundled fee would typically include a fee for holding gas in storage (B_s) and another component ($A_s \times w_s$) is a function of deliverability/withdrawal rate. Estimates of the parameters A and B are reported in Table A. 19.

Table A. 19: Estimates of the short-run marginal cost of gas withdrawal from storage facilities

Country/region	**A**	**B**
Austria	1.50	44.99
Czech Republic	27.12	32.33
Denmark	40.75	42.65
France	15.99	42.33
Germany	5.99	38.86
Hungary	2.00	45.42
Italy	2.35	42.53
Netherlands	11.04	22.00
Poland	52.00	22.00
Romania	1.77	45.47
Spain & Portugal	39.64	33.05
Great Britain	57.46	55.57

North America	1.15	24.61
Australia	106.65	22.00
South Korea	12.79	22.00
other storage sites*	39.48	33.62

Notes: * LNG, other storage sites & gas production flexibility

Source: The author's calculations are based on EC (2015) and Ramboll (2008), as quoted in Le Fevre (2013, Table 2, page 5).

Storage obligation for the EU27 is set at 90% of storage capacity to be reached by Nov 1 for all individual sites, including LNG storage facilities. The timeframe for this obligation is 2022 until the end of 2025, which aligns with the adopted EC regulation.

For European gas storage facilities, the initial volume of gas in storage at the beginning of each year (i.e., Jan 1) is assumed to equal 70% of storage capacity, an average value observed on Jan 1 in 2013-2022[24]. The initial volume of gas in North American gas storage facilities is assumed to be 72% by October, which aligns with historical data.

A.6.6 Natural gas transport

A.6.6.1 European pipeline system

- *The EU entry-exit pipeline system*

We take all cross-border gas interconnection capacity reported by the IEA gas flow dataset (2022) and Europe's 2021 ENTSO-G (2022) capacity map. This dataset is for all existing cross-border capacities in Europe. We aggregate interconnection points between any pair of countries to reduce the model size without losing insights. We rely on a project database in the latest 2022 gas TYNDP for future European network expansion. We only took those gas network expansion projects that took FID (Table A. 20).

As a proxy for the short-run marginal cost of transporting gas between European markets, we take 2021 cross-border tariffs collected by ACER[25]. While these transport tariffs may include short-run avoidable variable costs and some fixed costs, wholesale price differences between European gas markets have consistently approached those cross-border transport tariffs (e.g., Chyong 2019 and various ACER's gas market monitoring reports). This means cross-border gas trading in Europe considers those tariffs when transporting gas between markets (i.e., wholesale price differences are equal to transport cost; hence, arbitrage opportunities are exhausted). The ACER gas tariff dataset contains information for most interconnection points. We take a simple average of entry and exit tariffs and sum corresponding average values to compute a set of cross-border tariffs between each pair of markets in the EU.

Only the European region is modelled in detail, while other regions and countries are represented as single nodes (i.e., we do not consider internal bottlenecks for non-European regions). This is an area of research we leave for future improvements by researchers interested in expanding our model to other regions in greater detail.

[24] Source: https://agsi.gie.eu/
[25] https://aegis.acer.europa.eu/chest/dataitems/218/view

Table A. 20: European gas network expansion projects considered in the model

From	To	Project Name	Commissioning Year	Capacity (bcm/year)
Serbia	Bulgaria	Interconnection Bulgaria - Serbia	2022	1.92
Bulgaria	Serbia	Interconnection Bulgaria - Serbia	2022	1.92
Serbia	Bulgaria	Modernisation and rehabilitation of the Bulgarian GTS	2024	0.64
Bulgaria	Serbia	Modernisation and rehabilitation of the Bulgarian GTS	2024	0.64
Germany	Switzerland	TENP Security of Supply plus	2026	2.30
Poland	Ukraine	North-South Gas Corridor in Eastern Poland	2028	3.05
Norway (Dornum)	Denmark	Norwegian tie-in to Danish upstream system	2022	10.08
Denmark	Poland	Poland - Denmark interconnection (Baltic Pipe) - offshore section	2022	10.08
Poland	Denmark	Poland - Denmark interconnection (Baltic Pipe) - offshore section	2022	2.99
Latvia	Lithuania	Enhancement of Latvia-Lithuania interconnection (Lithuania's part)	2023	1.79
Lithuania	Latvia	Enhancement of Latvia-Lithuania interconnection (Lithuania's part)	2023	2.07
TAP Greece	IGB Bulgaria	Interconnector Greece-Bulgaria (IGB Project)	2022	4.66
Greece	IGB Bulgaria	Interconnector Greece-Bulgaria (IGB Project)	2024	3.94
Greece	IGB Bulgaria	Interconnector Greece-Bulgaria (IGB Project)	2027	1.12
Germany	Netherlands	Additional import at Oude StatenZijl area	2022	7.49
Germany	Netherlands	Additional import at Oude StatenZijl area	2025	1.97
Greece	TAP Greece	Booster Compressor Station for TAP in Nea Messimvria	2024	0.99
TAP Greece	Greece	Upgrade of Nea Mesimvria Compressor Station	2023	0.90
IGB Bulgaria	Bulgaria	Interconnector Greece-Bulgaria (IGB Project)	2022	2.96
IGB Bulgaria	Bulgaria	Interconnector Greece-Bulgaria (IGB Project)	2025	1.97

Source: ENTSO-g (2022)

- *The Norwegian offshore pipeline system*

Transport costs through the Norwegian offshore transmission system are based on calculations by Chyong and Hobbs (2014) (see Table A. 21).

Table A. 21: Offshore transport cost via the Norwegian Transmission System ($2021/tcm)

TO / FROM	UK (St. Fergus)	UK (Easington)	France (Dunkerque)	Belgium (Zeebrugge)	Germany and Netherlands (Emden/Dornum)
North Sea (Troll Field)	62.3	8.9	13.5	42.1	25.1
Norwegian Sea (Asgard Field)	73.5	17.8	24.7	53.3	36.3
Barents Sea (Snøhvit Field)	99.1	43.4	50.3	78.9	61.9

Source: Chyong and Hobbs (2014)

A.6.6.2 Non-European pipeline system

A.6.6.2.1 Transmission system within Russia

Following Chyong and Hobbs (2014), the cost of transporting gas via key transport routes within Russia is assumed to be $2/100km/tcm. The cost of transporting gas via the Nord Stream offshore and the BlueStream/TurkStream offshore sections is estimated at $24.2/tcm and $19.3/tcm, respectively (Chyong and Hobbs, 2014).

A.6.6.2.2 Transporting Russian gas via Ukraine and Belarus

- Ukraine

The cost of transporting gas via Ukraine is based on the current annual tariffs charged by the Ukrainian transmission system operator (see Table A. 22: for example, the entry charge for Russian gas at Sudja is $16.01/tcm and an exit charge at Slovakia border is $9.68/tcm resulting in total charge of $25.69/tcm).

Table A. 22: Ukrainian gas transport tariffs ($2021/tcm)

	Entry to Ukraine	Exit from Ukraine
Budince, Uzhgorod – Velke Kapusany (Slovakia)	4.45	9.68
VIP Bereg (Hungary)	4.45	9.25
VIP PL-UA (Poland)	4.45	9.04
Isaccea/Orlovka (Romania)	4.45	1.13
Tekove/Mediesu Aurit (Romania)	4.45	8.78
Kaushany (Moldova)	0	1.13
Grebeniki (Moldova)	0	8.17
Limanskoe (Moldova)	4.45	8.17
Sokhranovka (Russia)	16.01	
Sudzha (Russia)	16.01	

Source: Eikon Terminal

- Belarus

The transit fee for Russian gas across Poland is $1.05/100km/tcm, according to DW (2022). Similarly, Belarus reportedly charges $1.75/100km/tcm to transport Russian gas via its pipelines, which Gazprom owns (DW, 2022). Thus, given that the length of the Yamal-Europe pipeline in Belarus is 575 km and 683 km in Poland[26], the total per unit cost via Yamal-Europe is $17.23/tcm (via Belarus and Poland to Germany). In addition to the Yamal-Europe pipeline, Russia can use Belarus' Northern Lights pipelines to transport gas to Lithuania, Ukraine and Poland (see Table A. 23).

Table A. 23: Transit fee through Belarus' Northern Light system ($2021/tcm)

		Entry points
		Russia (Smolensk)
Exit points	Lithuania (Kotlovka)	8.01
	Poland (Brest)	10.50
	Ukraine (Kobryn)	10.50
	Ukraine (Mozyr)	6.37

A.6.6.2.3 Offshore Pipelines from North Africa to Spain and Italy

Following Chyong and Hobbs (2014), the cost of transporting gas via the Medgaz pipeline (Algeria to Spain) and the Transmed pipeline (Algeria to Italy via Tunisia) are $37.2/tcm and $70.2/tcm, respectively. Using the Greenstream pipeline (Libya to Italy) costs $69.6/tcm (Chyong and Hobbs, 2014). We should note that we assume no gas will flow via the Maghreb pipeline (Algeria to Spain via Morocco) due to the dispute between Algeria and Morocco. Further, we assume only partial capacity of the Greenstream pipeline (5.5 bcm/yr), based on historic flow from Libya to Italy.[27]

A.6.6.2.4 Other transborder pipelines

For other transborder pipelines, we assume 0.125% per 100 km of gas transported as the variable cost (Chyong and Hobbs, 2014). It should be noted that these "in-kind" charges are mostly for fuel to run compressors that are installed along pipelines. Here, we list the transborder pipelines in Eurasia and the Middle East that we consider in the model:

1. Central Asia – Center gas pipeline system to carry gas from Turkmenistan via Uzbekistan and Kazakhstan to Russia (4405 km);
2. Central Asia – China gas pipeline system (Line A, B, and C) running through Turkmenistan, Uzbekistan, Kazakhstan, and China (1833 km);
3. Dolphin Qatar–UAE Natural Gas Pipeline (370 km)
4. Sino-Myanmar Gas Pipeline (2520 km)
5. Dauletabad-Sarakhs-Khangiran Gas Pipeline (31 km)
6. Hajiqabul–Astara–Abadan Gas Pipeline (1475 km)
7. South Caucasus Gas Pipeline (692 km)
8. Tabriz-Ankara Pipeline (2577 km)
9. Trans-Anatolian Gas Pipeline (1841 km)

[26] https://web.archive.org/web/20211106190944/https://www.gazprom.com/projects/yamal-europe/
[27] https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/012120-libyan-gas-exports-to-italy-unaffected-so-far-by-oil-blockade

A.6.6.3 Pipeline annual planned maintenance

Finally, we assume that the annual planned and unplanned maintenance affects 0.32% of pipeline throughput capacity. This rate was calculated using a pan-European database of pipeline maintenance provided by the Eikon terminal. The database has information regarding the start and end date/time for planned (and unplanned) maintenance and the capacity affected by the maintenance. The calculated value is the capacity-weighted annual unavailable rate covering pipeline maintenance from 2013 to the present. Thus, we apply this value in the modelling.

A.6.6.3 LNG export and import

A.6.6.3.1 Global LNG capacity

The projection for LNG export and import capacity addition is based on Eikon's LNG database of LNG projects. For our projections, we only take the capacity of under-construction plants. Note that no projects are under construction to be delivered beyond 2026. Thus, LNG import capacity in 2027-2031 is set at the level reached by 2026.

Table A. 24: Projected LNG regasification capacity (bcm)

		2023	2024	2025	2026	2027	2028	2029	2030	2031
IMPORT CAPACITY	Australia	3	3	3	3	3	3	3	3	3
	Belgium	9	9	9	9	9	9	9	9	9
	China	182	197	205	205	205	205	205	205	205
	Croatia	3	3	3	3	3	3	3	3	3
	Estonia	4	4	4	4	4	4	4	4	4
	Finland	1	1	1	1	1	1	1	1	1
	France	36	36	36	36	36	36	36	36	36
	Great Britain	48	48	48	48	48	48	48	48	48
	Greece	13	13	13	13	13	13	13	13	13
	India	75	75	75	75	75	75	75	75	75
	Israel	5	5	5	5	5	5	5	5	5
	Italy	15	15	15	15	15	15	15	15	15
	Japan, Korea & Taiwan	495	495	495	500	500	500	500	500	500
	Lithuania	4	4	4	4	4	4	4	4	4
	Middle East	65	65	65	65	65	65	65	65	65
	Netherlands	21	21	21	21	21	21	21	21	21
	North America	210	210	210	210	210	210	210	210	210
	Pakistan	13	13	13	13	13	13	13	13	13
	Poland	5	5	5	5	5	5	5	5	5
	Portugal	8	8	8	8	8	8	8	8	8
	Rest of Africa	12	12	12	12	12	12	12	12	12
	Rest of Americas	94	94	94	94	94	94	94	94	94

	South East Asia	86	86	86	86	86	86	86	86	86
	Spain	63	63	63	63	63	63	63	63	63
	Sweden	1	1	1	1	1	1	1	1	1
	Turkey	26	26	26	26	26	26	26	26	26
EXPORT CAPACITY	Algeria	34	34	34	34	34	34	34	34	34
	Australia	119	119	119	119	119	119	119	119	119
	Middle East	127	127	172	172	172	172	172	172	172
	North America	116	132	169	204	225	229	229	229	229
	Norway	6	6	6	6	6	6	6	6	6
	Papua New Guinea	11	11	11	11	11	11	11	11	11
	Rest of Africa	70	70	81	81	81	81	81	81	81
	Rest of Americas	27	27	27	27	27	27	27	27	27
	Russia	39	48*	48	48	48	48	48	48	48
	South East Asia	90	90	90	90	90	90	90	90	90

Notes: * The first train of Novatek's Artic 2 project is expected to be online in December 2023; therefore, we assume its full capacity will be available at the start of 2024. Note that new capacity will have a ramp period of two years to reach full capacity (For example, if a project starts in 2025 with ten bcm/year, then in 2025, export capacity will be 10/2=5 and then in 2026 it will reach ten bcm/year).

Source: https://en.portnews.ru/news/340100/?utm_source=substack&utm_medium=email

In addition to the above projects, we consider the following "proposed" FSRU projects in Europe. We include these projects as most have approvals and are considered a priority to reduce dependency on Russian gas. Further, we should note that we model all LNG regasification terminals at the plant level for the EU and the UK markets.

Table A. 25: Additional FSRU terminals in Europe

Country	Start-up	Receiving capacity (bcm/y)	Storage capacity (bcm)	Project/Terminal
Finland	2022	5.0	0.09	Port of Inkoo
France	2022	4.3	0.09	Le Havre
Germany	2022	7.5	0.10	Brunsbüttel FSRU
Germany	2023	7.5	0.10	Stade FSRU
Germany	2022	7.5	0.10	Wilhelmshaven FSRU
Greece	2024	3.0	0.09	Aegean
Italy	2024	5.0	0.10	Coast of Ravenna
Italy	2023	5.0	0.10	Central-Northern Italy
Latvia	2024	4.1	0.08*	Skulte
Poland	2025	6.0	0.11*	Gdansk

Source: Eikon Terminal (LNG infrastructure database).

Notes: *Storage capacity for the Latvian and Poland's FSRU projects were not reported, so it was calculated assuming the average storage capacity per receiving capacity of the other projects in the table.

LNG export utilisation rate (in 2013-2019) averaged 92.4%[28] analysis. In our modelling, we take this average utilisation rate as the capacity factor for LNG exports to reflect planned and unplanned annual maintenance for export facilities.

The calculation of the LNG import terminal utilisation rate (reflecting planned and unplanned annual maintenance work) is based on the Eikon LNG project maintenance dataset covering 2018-2023. Thus, LNG import facilities worldwide have been taken offline for about 12.6 days per year for maintenance work, or 3.45% being unavailable.

The variable cost of LNG export is assumed to be 10% of fuel input, which is modelled as "losses" when feed gas is transported from a hub or a producing well to an LNG liquefaction facility. We should note that Cheniere, for example, charges its off-takers a 15% margin on top of the US Henry Hub spot price to cover the variable cost of liquefaction (the average value of fuel input to run the liquefaction processes is 11-13%, Stern (2019)).

A.6.6.3.2 Global LNG shipping

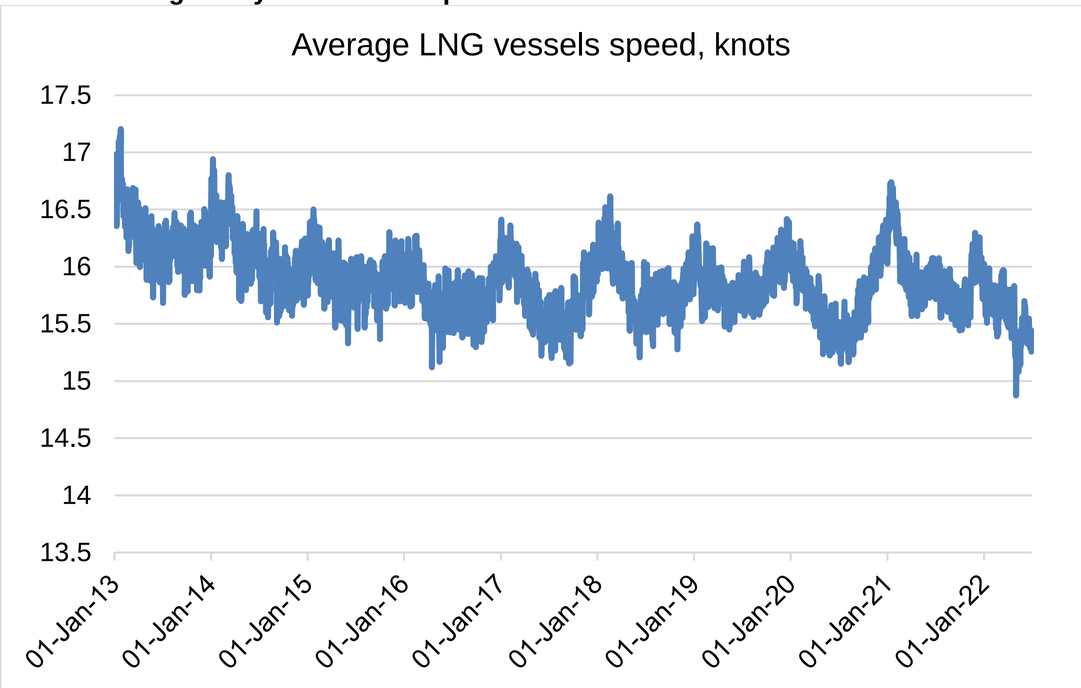
- *LNG shipping capacity*

According to the 2022 GIIGNL LNG report (GIIGNL, 2022), the total operational capacity of LNG vessels amounted to 95.9 million cubic meters of LNG[29] or 58.8 bcm of natural gas. LNG shipping capacity depends not just on vessels' carrying volume but also on their sailing speed (eq. A5)

$$LNG\_Ship\_Cap_{(y)} = Total\_Vessel\_Cap_{(y)} \times Average\_speed_t \qquad \text{(A5)}$$

LNG shipping capacity is measured in bcm.miles, total vessel capacity is measured in bcm of natural gas, and average speed is measured in nautical miles/month. In the model, I used the monthly average LNG vessel speed taken from an Eikon terminal for 2013-2022H1 (see Figure A. 4).

Figure A. 4: Average daily LNG vessel speed



Source: Eikon Terminal

[28] https://www.iea.org/data-and-statistics/charts/lng-liquefaction-capacity-and-utilisation-2013-2023
[29] Total operational capacity of all LNG vessels, including FSRU was 103 mn cubic meters; FSRU cargo capacity at the end of 2021 stood at around 7.1 mn cubic meters (GIIGNL, 2022).

- *LNG shipping routes*

The calculation of the LNG shipping cost is relatively straightforward. We assemble an exhaustive database of bilateral distances between pairs of existing and under-construction LNG export and import facilities using an online maritime distance calculator (https://sea-distances.org/). The resulting dataset contains 181 aggregated LNG import projects and 53 LNG export projects. Up to 8 routes between each pair of import-export projects, including a direct route, are considered through important straits and canals such as the Panama Canal, Suez Canal, strait of Good Hope, Cape Horn, Gibraltar, Malacca, Magellan, and Northern Sea Route. Overall, the LNG shipping routes dataset contains distances of 25,782 routes between existing and under-construction LNG projects. This dataset forms the basis of our endogenous LNG shipping cost modelling.

Further, shipping capacity through critical canals and straits is also considered. Suez Canal transit time is assumed to be 12 hours for a vessel to travel one-way and 24 hours for forward and return journeys[30]. According to GIIGNL (2022), the operational capacity of LNG vessels amounted to 103.0 million cubic meters of LNG or 58.8 bcm of natural gas. Thus, capacity through the Suez Canal is 34.1 bcm/year (assuming 6% of spare capacity for boil-off and heel).

The Panama Canal Authority offers only two slots for LNG vessels daily, resulting in ca. 37.5 bcm/year. The capacity is halved if these two slots are used for southbound and northbound journeys, i.e., 18.75 bcm/year.[31]

Northern Sea Route is assumed to have the following shipping capacity (2020 data from Kpler):

- Two cargoes in May;
- Three cargoes in June;
- Five cargoes in July;
- Nine cargoes per month in August and September;
- Four cargoes in October
- And tone cargo per month for the rest of the year.

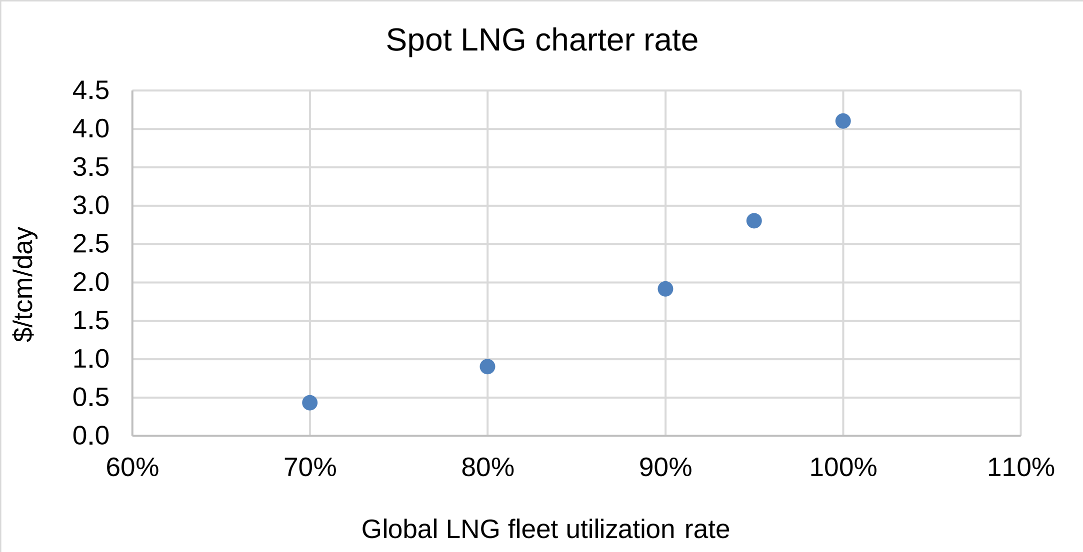
- *LNG shipping costs*

LNG shipping costs consist of the charter rate and fuel used to run ship engines. As for fuel to run the LNG ships, following Rogers (2018) research, we assume they run on LNG boil-off (daily boil-off rate for a Dual Fuel Diesel Electric, DFDE, LNG carrier is assumed to be 0.1%/day for laden trips and 0.07%/day for ballasting). The daily LNG charter rate is modelled endogenously by assuming a short-run marginal cost of LNG shipping as a function that shows a positive relationship between global fleet utilisation and spot charter rate (see Figure A. 5). The parameters of this marginal supply cost function are computed based on research done by Enderlin and David (2021). We linearise the cost function by modelling five steps:

1. When the global LNG fleet is less or equal to 70% utilisation rate (UR), the charter rate is $0.43/tcm/day;
2. when UR is between 70% and 80% - $0.90/tcm/day;
3. when UR is between 80% and 90% - $1.91/tcm/day;
4. when UR is between 90% and 95% - $2.80/tcm/day;
5. and, finally, when UR is between 95% and 100% - $4.10/tcm/day.

[30]https://www.suezcanal.gov.eg/English/Pages/FAQ.aspx#:~:text=%E2%80%8BThe%20canal%20is%20owned,takes%2012%20to%2016%20hours.
[31]https://iea.blob.core.windows.net/assets/5aa5170d-8dcd-4b99-b8b9-c761ad3a84ed/GasMarketReportQ22021.pdf

Figure A. 5: Cost function for spot LNG charter rate



Source: adapted from Enderlin and David (2021)

Other techno-economic parameters for LNG shipping modelling are taken from Rogers (2018) research and assumptions in the Eikon Terminal's LNG voyage cost methodology. In particular:

- Tanker loading is assumed to be 94% of the cargo capacity, allowing for 2% vapour space to limit dangerous pressure build-up and 4% as heel left for a return (ballast) voyage;
- Suez Canal transit fee is assumed to be $0.225/MMBtu, or $8.679/tcm;
- Panama Canal transit fee is assumed to be $0.22/MMBtu, or $8.486/tcm;
- The transhipment cost for Yamal Westward LNG voyages is assumed to be $0.10/MMBtu or $3.857/tcm;
- Port costs (non-regasification or liquefaction-related costs): $100,000/day/cargo; assuming 160,000 cubic meters LNG vessel and 98% loading, this port charge results in $1.12/tcm. This fee is added to the variable cost of liquefaction (2 days) and regasification (1 day);
- Port days: 3 days, including one day at the export port, one day at the import port, and one day at the return destination port;
- Agents, broker fees, and insurance: 2% of charter cost plus $2,600/day for insurance.
- Two compulsory dry dockings are assumed to be every five years, with 30 days per dry dock.[32]

Finally, it is worth noting that the charter cost and boil-off apply to roundtrip between origin and destination (Rogers, 2018).

A.6.7 Conversion factors and exchange rate

The model uses US Dollars as the reporting financial unit and MW and MWh-th as capacity and energy units. Therefore, all parameters reported in this paper were converted to these units using the following conversion factors:

- Capacity of gas infrastructure: bcm/year
- Capacity of electricity infrastructure: MW
- 1bcm of gas = 11,111,100 MWh-th of gas

[32] https://seekingalpha.com/article/4223891-lng-shipping-economics

- 1 thousand cubic metres (tcm) = 11.1111 MWh-th of gas
- 1 $/tcm = 0.09 $/MWh-th
- 1 $/MMBtu = 38.5714 $/tcm
- 1 metric tonne of coal is assumed to equal 22.01987 GJ[33]
- 1 tonne of coal equivalent (TCE) is assumed to equal 29.3076 GJ or 8.141 MWh[34]
- 1 GJ is assumed to equal 0.277778 MWh-th[35]
- 1 liquid cubic metre of LNG equals 571 natural gas (in gaseous form)[36]
- We use the 2021 average Euro to USD exchange rate of 1.1827 per ECB[37]
- All costs and prices are reported in real 2021 US dollars

[33] https://www.eia.gov/energyexplained/units-and-calculators/energy-conversion-calculators.php
[34] http://extraconversion.com/energy/tonnes-of-coal-equivalent
[35] https://www.inchcalculator.com/convert/gigajoule-to-megawatt-hour/#:~:text=To%20convert%20a%20gigajoule%20measurement,energy%20by%20the%20conversion%20ratio.&text=The%20energy%20in%20megawatt%2Dhours,the%20gigajoules%20multiplied%20by%200.277778.
[36] See GIIGNL (2017) LNG report (page 36)
[37] https://www.ecb.europa.eu/stats/policy_and_exchange_rates/euro_reference_exchange_rates/html/eurofxref-graph-usd.en.html

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