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ENVIRONMENTAL
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ASSESSMENT OF GAS INTAKE AND ASSOCIATED EMISSIONS IN NORTH MACEDONIA

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IN NORTH MACEDONIA

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ABBREVIATIONS

bcm	billion cubic meter
CCGT	Combined Cycle Gas Turbine
CCS	carbon capture and storage
DESFA	National Natural Gas System Operator S.A. (Gas TSO Greece)
EBRD	European Bank for Reconstruction and Development
EIB	European Investment Bank
ENTSO G	European Network of Transmission System Operators for Gas
GWh	Gigawatt hours
FID	Final Investment Decision
JKM	Japan Korea Marker
LNG	Liquefied Natural Gas
LTC	Long-term contract
PECI	Project of Energy Community Interest
TAP	Trans-Adriatic Pipeline
TYNDP	Ten Year Network Development Plan
WBIF	Western Balkans Investment Framework



EXECUTIVE SUMMARY

The goal of this study was to assess the impact of the new Greece-North Macedonia gas pipeline and the planned new CCGT power plants on the gas prices, and flows in the region and on the changes on the electricity mix of the Macedonia and related CO₂ emissions.

BACKGROUND

The new GR-MK pipeline adds another supply route to North Macedonia, that at the time of writing this study (fall 2025) imports all its gas via the existing interconnector between Bulgaria and Macedonia. This pipeline is now mainly transporting Russian gas that is delivered via the Turk Stream pipeline and Bulgaria. Since 2023 however first amounts of non-Russian sources gas were reported to arrive to Macedonia via Bulgaria. The new interconnector adds another gate to the Greek LNG terminals capacity, providing access to the global LNG market and with the direct connection to the TAP pipeline Azeri gas shipped via the TAP pipeline can also provide new pipeline sources.

The additional fuel need of the planned new CCGTs would substantially increase the current (3 TWh/yr in 2024) Macedonian gas demand with an assumed 55% efficiency and 60% utilization to 13 TWh when they enter the market. However, this utilization depends on market circumstances and competing CCGTs in the region. It is also the task of this study to assess how these new CCGT plants would be utilized at different gas price levels. There are also other CCGT plans announced in the region (in Romania, Greece, ...) that would certainly impact

the North Macedonian electricity market and the competitiveness of the planned new CCGT units in North Macedonia.

METHODOLOGY

We modelled the gas price and flow impacts of the new pipeline with the European Gas Market Model (EGMM) in two main scenarios: with and without the new GR-MK pipeline; and with and without the new CCGT plants. To test the robustness of our results sensitivity runs were carried out for different global price environments (Japanese Price at 20, 40, 50 EUR/MWh) and with stagnating EU gas demand (reference scenario), lower demand (-15%) and higher demand (+15%)

For the electricity modelling we used the European Power Market Model (EPMM). Using two gas price projections based on the EGMM runs (a higher and a lower gas price) we tested the utilization of the new CCGT capacities in North Macedonia in our best estimate infrastructure scenario, where only the most developed CCGT plans materialize (low infrastructure scenario). However these project plans can change and neighboring countries CCGT outbuild can have a serious impact on the Macedonian CCGTs profitability, therefore our first sensitivity scenario tests higher CCGT outbuild in the region. As we assumed that North Macedonia joins the ETS by 2030 we run a second sensitivity to see how a potential delayed implementation by 2035 changes electricity wholesale prices, the utilization of the power plants and the emissions of North Macedonia and the region.

GAS MODELLING RESULTS

The gas market modelling main findings are the following:

- The new GR-MK pipeline provides another supply route to new sources.
- However, it does not have or in certain scenarios it has a negligible regional impact on the gas markets depending on the scenario. The reason for that is that MK consumption doubled since 2014 and is about to triple from 2024 to 2030 if all CCGTs are built and run. Still the highest estimates are at a yearly 1.3 bcm consumption, that is negligible from the European gas market point of view.
- The pipeline and the power plant investments' gas demand need therefore have its effect limited to North Macedonia. If only the pipeline is commissioned, the price effect is a decrease by 1.5 EUR/MWh. With additional CCGT demand, the effect drops to a decrease of 0.3-0.5 EUR/MWh compared to the without CCGTs and no pipeline scenario. In the current price environment (30-40 EUR/MWh) it is between 1-5% change. Regarding price effects, results are robust to both the demand and global price sensitivities.
- Flow patterns and utilisation of infrastructure show that when only the pipeline is commissioned, all flows from the BG-MK interconnector are redirected to the new route. If additional CCGTs are added to the Macedonian demand, the pipeline is used nearly at capacity, but the BG-MK route is also needed to meet the increased demand.

ELECTRICITY MODELLING RESULTS

- North Macedonia can securely operate without the completion of the new CCGTs but will rely heavily on imports. Our modelling estimates import to consumption ratio at 30% in 2030 which decrease to 25% until 2040. There is however no energy not supplied, which means that the higher import dependency is not associated with increased security of supply risk, as many countries in Europe safely operate with high import ratio.
- Completion of the new CCGTs brings only a short-term decrease in wholesale electricity prices in North Macedonia, with the effect diminishing over time (around 10 EUR/MWh in 2030, 0-2 EUR/MWh in 2040).
- The utilisation of the new CCGTs is above 70% in 2030 but decreases over time. In most cases, it drops well below 40% by 2040, and in one case down to 5-6%. Only if reference gas prices are assumed and no other CCGT investments occur in the region, it remains just above 40% throughout the entire period.
- A new CCGT project could only both be profitable and reduce GHG emissions in the region under a narrow set of conditions: it is correctly sized (likely a single project rather than two), investment costs remain within a reasonable range, European gas prices are around €40/MWh, and there is no major expansion of regional CCGTs.
- New CCGTs increase CO₂ emissions in North Macedonia and make it more difficult to meet its climate commitments.
- If only a few planned CCGTs are built in the region, the new plants in North Macedonia would decrease CO₂ emissions in the close proximity because they substitute coal.

SENSITIVITY RESULTS

- Increased CCGT deployment across the Balkans leads to slightly lower prices in North Macedonia, increased competition, thus lower utilisation of the North Macedonian new gas power plants as well as slightly higher regional CO₂ emissions.
- Late ETS joining of the WB6 region results in lower prices and higher utilisation of the North Macedonian CCGTs, but significantly higher emissions in both MK and the region. Joining the ETS is closely connected to EU accession so cannot be considered in isolation.

KEY MESSAGES

Overall, the findings highlight the delicate balance between, economic efficiency, and environmental sustainability, and emphasise the **importance of coordinated regional planning** when considering new gas power investments. On a regional level a limited amount of new CCGT power plants would in a transitional period **support regional decarbonization** by substituting existing coal-based power generation.

Current plans are overblown. Building two CCGTs in North Macedonia would not be financially viable. There are competing project plans in the region which would cannibalize the market and increase the CO₂ emission.

There is a trade-off: countries must decide whether they build a CCGT and emit CO₂ respectively or they opt for decarbonization and renewables and rely more on electricity imports. New CCGTs reduce electricity import dependency, but **the system can safely operate without the CCGTs.**

There are certain country related **benefits**, but they **are short living**: Would a CCGT enter the Macedonian market in 2030 a 10 €/MWh **price decrease** (~10%) could be expected for the benefit of the consumers. This price damping effect however melts down by 2040 to a negligible 0-2 €/MWh.

To strengthen the projects profitability investors would be interested in lobbying for an ETS prolongation, that would result in significantly higher emissions both in North Macedonia and in the region.



2

INTRODUCTION

2.1. PIPELINE INVESTMENT BETWEEN GREECE AND NORTH MACEDONIA

Currently, Macedonia is only connected to Bulgaria via pipeline and is mainly supplied with Russian long-term contracted gas. Since 2023 however first amounts of non-Russian sources gas were reported to arrive to Macedonia via Bulgaria¹. The planned new interconnector with Greece will be referred to as the GR-MK pipeline. The GR-MK interconnector links North Macedonia to TAP pipeline system in Greece and allows to access pipeline gas from Turkey, Italy, Azerbaijan and LNG from Greek terminals. The new interconnector would have a positive effect of adding a second supply route to the Macedonian market. Project promoters also highlighted the security of supply dimensions of the new pipeline.

As of 2025, The North Macedonia – Greece interconnector is a project under construction. A joint agreement of Greece and Macedonia was signed in

2021.² The national TSOs are responsible for building the pipeline sections on their national territory. The pipeline was awarded PECL status in the 2018 and 2020 PECL selection rounds, when natural gas pipelines could still apply for this title, which is not the case since the new TEN-E regulation entered into force in 2022³. Expected commissioning of the pipeline is 2025 December, commercial operation is to start in January 2026.⁴ As of 2025 September, the pipeline is already under construction and according to the Promoter's plans is expected to enter commercial operation by 2027.

The project connects North Macedonia to the TAP pipeline system with a 66 km pipeline in Macedonia and a 56 km line in Greece. Annual capacity of the pipeline was announced 1.5 bcm/year, but according to the latest TYNDP of DESFA (Greek TSO) it was expanded to 1.8 bcm.⁵ (Figure 1)

ENTSO TYNDP lists the projects under the code TRA-F-967, Pipeline Nea Messimvria – Evzoni/Gevgelija and Metering Station, promoted by DESFA. Capacity is announced 28 GWh/day. However, based on the announced 1.5-1.8 bcm/year capacity

¹ President Siljanovska Darkova in a press conference on 12 March 2025: "North Macedonia received first commercial gas from Azerbaijan in late 2023, totaling 12 million cubic meters. In December 2023, ESM Prodazba, the gas division of North Macedonia's ESM power utility, announced the start of natural gas purchases from the Bulgarian trader Graystone Bulgaria Ltd. The supplied gas mix includes both Azerbaijani and American products. Gas deliveries from Azerbaijan to North Macedonia continued in 2024 with a more systematic and organized approach." See: <https://caspiannews.com/news-detail/north-macedonia-seeks-more-natural-gas-imports-from-azerbaijan-2025-3-12-28/>

² <https://www.argusmedia.com/es/news-and-insights/latest-market-news/2233336-greece-north-macedonia-sign-deal-for-gas-line?backToResults=true>

³ https://energy.ec.europa.eu/topics/infrastructure/trans-european-networks-energy_en

⁴ <https://www.argusmedia.com/en/news-and-insights/latest-market-news/2619638-greece-north-macedonia-gas-link-delayed-by-22-months>

⁵ https://www.desfa.gr/wp-content/uploads/2024/09/Draft-Development-Plan-2024-2033_04092024_pc_vf.pdf
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Figure 1.
Routing of the pipeline from Nea Messimvria to the border with North Macedonia
Source: DESFA TYNDP 2024



Table 1.
Main characteristics of the interconnector
* No entry-exit tariff system exists. System users pay a domestic exit tariff.

Source: REKK assumptions based on publicly available sources

	Capacity, GWh/day	Length (km)	Investment cost (M EUR)	Tariff (EUR/MWh)	Commissioning
GR-MK (GR part)	40	56	92.04	0.48	2027
MK-GR (MK part)	40	66	120	0*	2027

this should rather be 30-50 GWh/day. DESFA has done a market test for the planned interconnector in 2022, with reserve prices 4.1717691 EUR/(kWh/h)/y (~0.48 EUR/MWh).⁶ This means that capacities for this pipeline can be booked on a long-term basis on this price. The reserve price will be the tariff for the pipeline use in case there is no congestion on the pipeline.

The project has received financing from several European donors: WBIF (investment grant of 12.724 Mn EUR)⁷, EIB (41 Mn EUR)⁸ and EBRD (98.6 Mn EUR loan)⁹ all provided loans and grants for the realisation of the pipeline.

2.2. CCGT POWER PLANT INVESTMENT

Besides the GR-MK gas pipeline investment, two additional combined cycle gas turbines (CCGTs) are planned at Bitola (250-300 MW) and Negotino (800 MW). The new pipeline would cover the additional gas demand of these power production capacities. The newly planned gas-fired units would replace the current lignite-fired Bitola and Oslovej and fuel-oil fired Negotino power stations.

Power sector in North Macedonia is dominated by fossil generating capacities: over 80% of major power plants are fuelled by lignite (55%), heavy fuel oil (11%) or natural gas (17%). Reservoir-type hydro account for 18% of installed capacities. Besides these non-intermittent capacities, some run-of-river hydro, PV and wind capacities operate in the country.

⁶ <https://www.desfa.gr/wp-content/uploads/2024/03/FEK-Greece-North-Macedonia-250722.pdf>

⁷ <https://www.wbif.eu/investmentgrants/WB-IG04-MKD-ENE-01>

⁸ <https://www.eib.org/en/projects/all/20180836>

⁹ <https://www.ebrd.com/home/work-with-us/projects/psd/51747.html#customtab-aeb523f4f0-item-fb1599966a-tab>

Table 2.
Installed electricity
generating capacity
in North Macedonia of
major plants (above 100
MW), 2025

Source: ENTSO-E
transparency platform

Name	Production Type	Installed capacity (MW)	Commissioning Date	Planned de-commissioning
BITOLA	Lignite	699	1982	2030
OSLOMEJ	Lignite	125	1980	2030
TEC Negotino	Heavy Fuel Oil (HFO)	210	1978	2030
TE-TO	Natural Gas	251	2012	-
TIKVES	Hydro Water Reservoir	114	1966	-
VRUTOK	Hydro Water Reservoir	150	1957	-

Future CCGT power plant investments aim to replace the existing local lignite and fuel oil fired units with gas fired capacities. The newly commissioned gas-fired plants are to be hydrogen ready. This means that less emitting but still fossil fuel-based power production enters the system with the future potential to use carbon capture storage (CCS) or switching to decarbonized gases e.g. biogas or hydrogen, that can be clean if produced from green electricity. Currently the green hydrogen market is infant and we are not aware of any CCGT in the world running only on hydrogen due to the lack of green hydrogen, but the technical potential for this technology being developed for new turbines as it is a requirement against new CCGT investments.¹⁰ There are numerous test cases and pilots and the technology providers seem to be confident about the partial hydrogen readiness of their projects, however the lack of commercial viability of hydro-

¹⁰ In March 2022, the EU adopted the Complimentary Climate Delegated Act (CCDA) setting conditions under which fossil-fuel-based gas (or "gas") is considered a "sustainable" activity in the EU Taxonomy on Sustainable Activities (EU Taxonomy). The CCDA provided two hard-to-achieve technical screening criteria related to emissions intensity, of which one must be met: Direct emissions intensity of less than 270g CO₂e/kWh, applying only when the facility's construction permit is granted before 2031, or lifecycle emissions intensity of less than 100g CO₂e/kWh. The 270g CO₂e/kWh direct emissions threshold is particularly notable as it allows for an increase in emissions intensity above the EU's predetermined alignment threshold of 100g CO₂e/kWh applied to other activities in the EU Taxonomy. Due to this exception, the direct emissions intensity threshold requires additional criteria to be met, such as evidence that the gas power generation replaced coal power generation within a 15% capacity range. Studies find based on evidence of projects who disclose information on their lifecycle emissions requirements that testing Scope 3 emissions may be challenging at the entity level, let alone at the facility level required by the EU Taxonomy. (See: [EU Taxonomy: Is There Sustainable Gas-Fired Power Generation?](#))

gen based power production prevents the market from development.

Additionally, REKK carried out an analysis for the Balkan region¹¹, which examined the impact of hydrogen-based operation. It concluded that even if green hydrogen were available in sufficient quantities, the fuel cost would be much higher than that of natural gas, so producers would only adopt this option if required by regulation. In such a case, however, there would be serious concerns regarding profitability of these power plants.

Table 3.
Potential power
plant investments

Name	Production Type	Installed capacity (MW)	Commissioning Date
NEGOTINO 2	Fossil gas, hydrogen	800	2030
BITOLA 1R	Fossil gas, hydrogen	250-300	2030

¹¹ https://rekk.hu/downloads/projects/REKK_Technical_Report_GasPP_final2.pdf

3

METHODOLOGY AND SCENARIOS

To address the questions related to the new pipeline and the planned new CCGT. We will apply a combined use of gas and electricity market modelling.

STEP 1: Gas market modelling

STEP 2: Electricity market modelling

The gas market modelling will provide gas price scenarios for the electricity market modelling and the electricity market modelling will show how the planned new CCGTs will impact the electricity mix and related emissions of North Macedonia and the region.

STEP 1. GAS MARKET MODELLING

Effects of the GR-MK interconnector in the gas market is assessed with market modelling using REKK' European Gas market model. The detailed description of the model is included in the Annex. We want to see how the new pipeline is changing the prices and flows compared to the current situation, but we also want to see how the new pipeline would change prices and flows if there would be additional demand coming from the planned new gas fired power plants.

Modelling will show the effects along these two main dimensions:

- With and without new GR-MK interconnector

- With and without new CCGTs (Bitola and Negotino)

Outcomes of the scenarios will be compared to a base case, which is without the new interconnector and without the new CCGT demand. These two dimensions would show four distinct scenarios, one of which (without the interconnector BUT with additional CCGTs) is disregarded, as the increased demand of power sector can not be met with the existing infrastructure.

Table 4.
Modelled gas market scenarios for North Macedonia

	Without CCGTs	Length (km)
Without GR-MK interconnector	Base	-
With GR-MK interconnector	Pipeline	Pipeline + CCGT

As the new CCGT capacities are expected to enter from 2030, the modelled years are 2030, 2035 and 2040.

Besides a reference case, sensitivities for LNG supply and demand balance (20/30/40/50/60 EUR/MWh) as well as on the European gas demand will be tested (~3500 TWh +/-15%).

STEP 2: ELECTRICITY MARKET MODELLING

Table 5.
Estimated scenarios in the electricity market modeling

Scenario name	European gas price	Macedonia CCGTs built	Regional CCGT expansion	WB6 ETS entry date
LowGas_wo	Low	No	No	2030
LowGas_wi	Low	Yes	No	2030
REF_wo	Reference	No	No	2030
Ref_wi	Reference	Yes	No	2030
LowGas_CCGT_wi	Low	Yes	Yes	2030
REF_CCGT_wi	Reference	Yes	Yes	2030
LowGas_lateETS_wi	Low	Yes	No	2035
REF_lateETS_wi	Reference	Yes	No	2035

Electricity market modelling is performed using REKK's EPMM, a unit commitment power market model. The model is suited to show the utilisation of the newly commissioned CCGT plants and identify the main drivers which affect the profitability of the units. Gas price outputs of EGMM are fed into the EPMM model, selecting a higher and a lower gas price pattern from the scenarios described above.

First, the effects of completing the new CCGTs are analysed using the incremental approach, where a scenario when the CCGTs in North Macedonia are completed (wi) compared with a scenario in which the power plants are not built (wo). This analysis is conducted under two distinct gas price patterns derived from the EGMM model, assuming a Reference gas price level (REF, about 40 €/MWh), while the in the other case a significantly lower European (and North Macedonian) gas price (LOW about 20€/MWh).

Under these scenarios, it is assumed that a limited amount of new gas capacity, approximately 7 GW, will be completed in the Region¹², and that North Macedonia will join the EU ETS in 2030.

¹² Gas power plant expansion is considered in the West Balkan six (WB6) countries: Albania, Bosnia and Herzegovina, Kosovo, North Macedonia, Montenegro and Serbia and countries in close proximity: Bulgaria, Croatia, Greece, Hungary, Moldova, Romania and Slovenia.

In the case when new CCGTs are completed in North Macedonia, two additional sensitivities are considered. The first examines a large-scale deployment of new gas power plant capacities, amounting to around 12 GW (excluding North Macedonia) within the region. The second considers a delayed entry of WB6 countries into the EU ETS in 2035, with the Carbon Border Adjustment Mechanism (CBAM) remaining in place until that time. The list of all scenarios is summarised in Table 5. The underlying assumptions of the scenarios are presented in 4.2.

The years 2027, 2030, 2035, and 2040 are modelled in the analysis.

4

MODELL INPUTS AND ASSUMPTIONS

4.1. GAS MARKET MODELLING

Main modelling inputs for demand and production in the scenarios were agreed upon the kick-off meeting (Sept 2025), as well as the infrastructure

scenarios. The table below summarises main input assumptions, which are described in detail in the following chapters.

Table 6.
Model input data

	Unit	2024	2025	2027	2030	2035	2040
DEMAND assumption							
EU27	TWh/ year	Eurostat historical 2023	National Trends	National Trends			
GAS PRODUCTION assumption (EU)							
EU	TWh/ year	Eurostat historical 2023	National Trends	National Trends			
INFRASTRUCTURE increments (ENTSOG based low advanced)							
Transmission capacity technical (any extension, or new pipeline) and tariffs on IPs	GWh/ day	ENTSOG extended by ACER, AIT, E-Control data and information		ENTSOG TYNDP Low advanced infrastructure			
LNG liquefaction and regasification	GWh/ day	ENTSOG extended by ACER, AIT, E-Control data and information		Global Energy Monitor gas infrastructure tracker 2024 ENTSOG TYNDP Low advanced infrastructure			
Storage capacity	TWh/ year, GWh/ day	ENTSOG extended by ACER		ENTSOG TYNDP Low advanced infrastructure			

4.1.1. DEMAND

Annual gas demand in TWh/year is based on ENTSOG National Trends scenario of the ENTSOG 2022 TYNDP¹³ (Ten-Year Network Development Plan). ENTSOG covers the gas demand for the EU27, while the scope of our modelling covers non-EU27 countries as well, which are part of the interconnected European gas pipeline network.

For non-EU27 countries, we assumed stagnating gas demand based on historical figures.

Monthly distribution of annual demand is derived from the 2019-2023 historical average consumption distribution. For EU27, Eurostat¹⁴ historical data was the source for the monthly distribution of gas consumption. Historical gas consumption for non-EU27 countries was based on the JODIGAS¹⁵ data initiative.

Demand is characterised by a downward-sloping demand function, the elasticity of the demand function was assumed low (0.01).

Sensitivity scenarios:

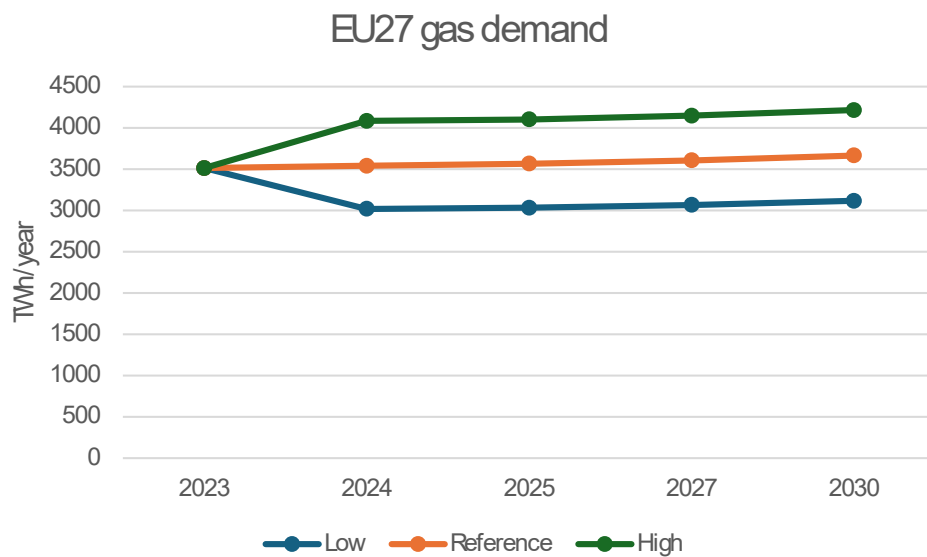
Two sensitivity cases are tested for demand: a demand level 15% above (high) and 15% below (low demand) the initial trajectory (reference demand).

For EU27, reference demand means ~3 500 TWh/year gas consumption in 2023. High demand levels mean ~4 000 TWh/year, which corresponds to the EU27 gas demand before the energy crisis. Low demand shows an extreme with ~3 000 TWh/year. (Figure 2)

For North Macedonia, gas demand was set at 3.65 TWh/year for scenarios without CCGT expansion, and 13.21 TWh/year for scenarios with additional CCGT capacities. Future gas demand assumed a 55% efficiency of gas-fired units and a 60% load factor of the power plants Negotino (800 MW) and Bitola (300 MW). **This means that in our CCGT scenario the North Macedonian gas demand would more than triple compared to 2024.**

Figure 2.
Annual gas demand assumed in the EU27, TWh/year (2023-2030)

Source: ENTSOG TYNDP



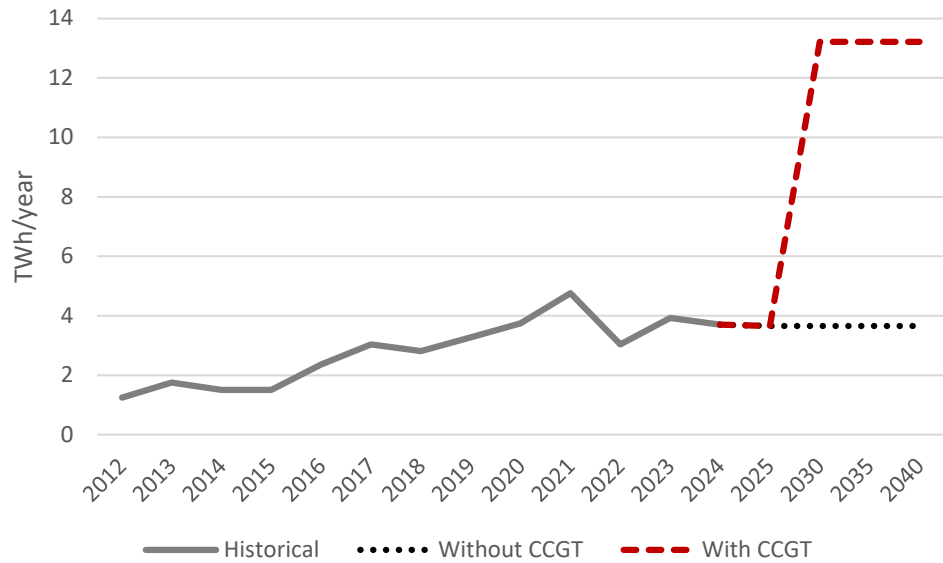
¹³ https://www.entsog.eu/sites/default/files/2023-09/TYNDP2022_Joint_Scenario_Full-Report-April-2022.pdf

¹⁴ Supply, transformation and consumption of gas - monthly data [nrg_cb_gasm]

¹⁵ <https://www.jodidata.org/gas/>

Figure 3.
Annual gas demand assumed in North Macedonia, TWh/year (2023-2030)

Source: State Statistical Office and REKK assumption on future gas demand



4.1.2. PIPELINE INFRASTRUCTURE

The European pipeline system is represented by the interconnector capacities as reported by the ENTSOG TYNDP. For all interconnector points, the lesser rule applies¹⁶. Capacities on the same borders are aggregated to one single IP (Virtual Interconnection Point) on each border even if more physical entry points exist.

The EGMM inputs do not consider internal bottlenecks. We assume that the capacities reported by the TSOs are firm capacities. There EGMM **is not modelling the hydraulic flows** of the assumed scenarios.

Pipeline capacity is partly reserved by the long-term supply contracts (LTCs) along the delivery route of the contracts. **The model does not consider contractual congestion.** The capacity that is not used by the LTC for delivering gas can be used for spot trading at the regulated (yearly) tariffs applicable on the respective IPs. We do not apply seasonal or monthly factors as a simplification the yearly tariffs are applied. Changes of the tariffs, caused for example by changing OPEX or cost of capital over time, are not taken into consideration.

In **case physical congestion** of the pipelines the price on the adjacent markets will divert and the congestion rent of the TSOs will increase.

Pipeline capacities for North Macedonia are listed in Table 7 below.

Table 7.
Daily capacities at North Macedonian IPs for modelling, GWh/day

	Daily capacity, GWh/day			
	2025	2030	2035	2040
BG-MK	32.47	32.47	32.47	32.47
GR-MK	0	40	40	40
MK-GR	0	40	40	40

4.1.3. GAS STORAGE CAPACITIES

Our model is using the data of Gas Storage Europe (GSE) for existing and planned capacities in Europe. There is no gas storage facility operating in North Macedonia nor is it planned in the near future.

4.1.4. LNG LIQUEFACTION AND REGASIFICATION CAPACITIES

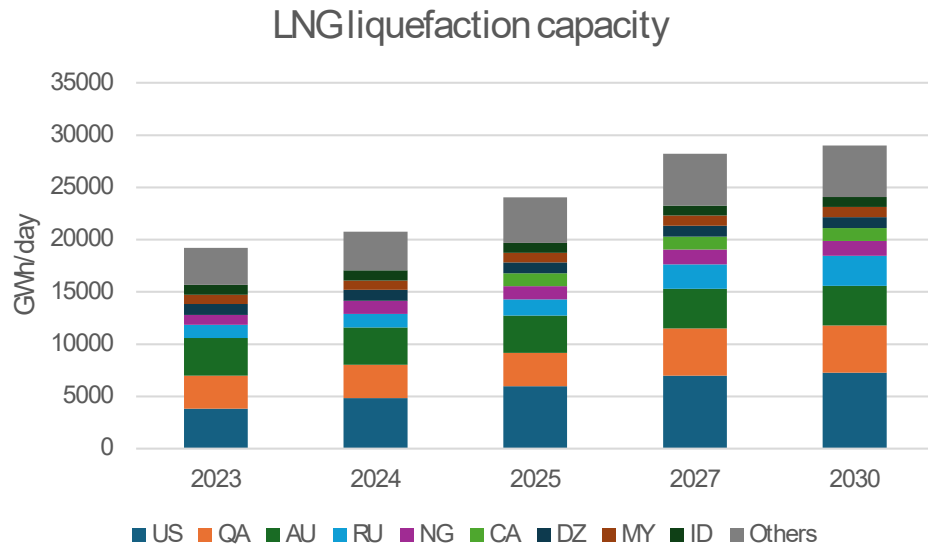
There is a consensus that LNG supply will significantly increase in the next years.

With a conservative approach, we only consider liquefaction facilities that are under construction or have secured FID (Final Investment Decision) already. This results in a 50% increase of global LNG-supply by 2030. This assumption is in line with ACER (2024) MMR European LNG market developments¹⁷.

¹⁶ Lesser rule means that in case TSOs on the two sides of the border report different capacities for the same interconnection point, the smaller capacity will be used in the modelling.

¹⁷ https://www.acer.europa.eu/sites/default/files/documents/Publications/ACER_2024_MMR_European_LNG_market_developments.pdf

Figure 4.
Total LNG liquefaction capacity by region, GWh/day
Source: Global Energy Monitor Gas Infrastructure Tracker 2024¹⁸



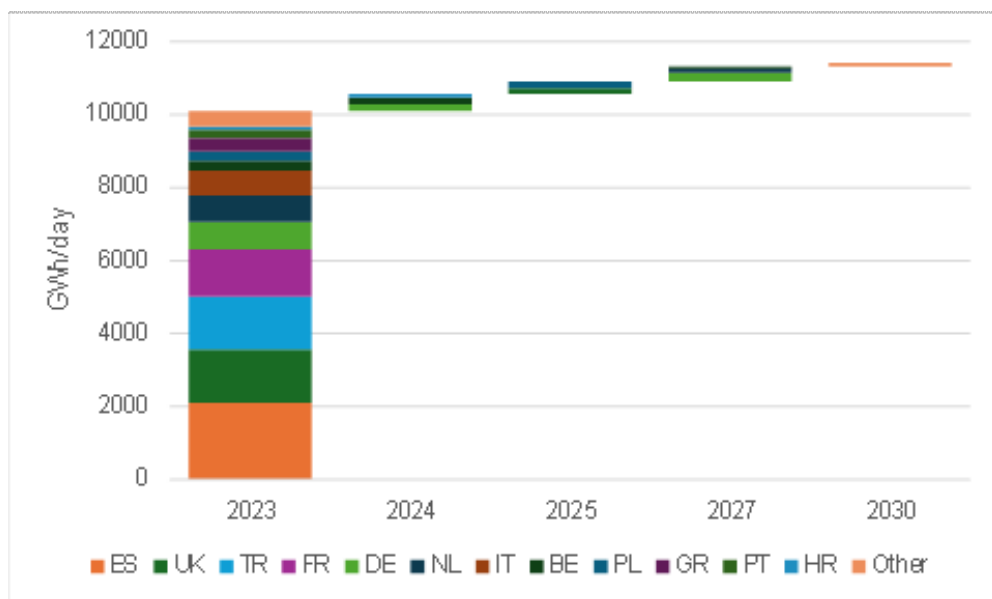
Most capacity additions are expected in the US and Qatar.

LNG supply cost to Europe is calculated for each supply source based on a netback market value concept calculation where the alternative destination is the Asian market, more precisely the Japan Korean Marker (JKM).

From 2023 to 2030, total LNG regasification capacities are expected to grow by 13% from 10 095 GWh/day to 11 420 GWh/day. Additional regasification capacity to come online is expected in Germany, Belgium, Poland, Netherlands, Croatia, Sweden and the UK.

North Macedonia is a land locked country, but the new GR-MK pipeline will provide access to the Greek LNG terminals. North Macedonian company ESM has already booked capacity on the new Alexandroupolis terminal that currently cannot be utilized¹⁹. In our modelling we assume that LNG sources will be available for North Macedonia on the nearby terminals (in Greece).

Figure 5.
Total LNG regasification capacity in Europe by 2023 and capacity additions by 2030, GWh/day
Source: ENTSOG System Capacity Map 2024²⁰



¹⁸ <https://globalenergymonitor.org/projects/global-gas-infrastructure-tracker/>

¹⁹ https://www.euractiv.com/short_news/north-macedonia-to-reserve-capacities-at-alexandroupolis-lng-terminal/

²⁰ <https://www.entsog.eu/maps#>

4.1.5. RUSSIAN PIPELINE CONTRACTS

During the course of the energy crisis, Russian long-term contracts, which provided nearly 40% of European imports before have gradually been terminated or suspended. Except for a few EU Member States and Balkan countries, Russian pipeline gas nearly disappeared from the European supply. Existing long-term contracts were listed based on OIES quarterly gas review:

“Supplies from Russia continue to be delivered exclusively via the Turkish Stream pipeline to Gazprom’s long-term contract counterparties in Greece, North Macedonia, Serbia, Bosnia-Herzegovina, Hungary, and Slovakia. For deliveries to counterparties in Greece, Gazprom’s contracts with DEPA (2 Bcma) and Prometheus (0.8 Bcma) expire in 2026 and 2027, respectively, while Gazprom’s contracts with Mytilineos in Greece (0.2 Bcma until 2030), SPP in Slovakia (3.5 Bcma until 2034), and MVM in Hungary (4.5–6.5 Bcma until 2036) expire later.”²¹

“This leaves 15.1 Bcma of Gazprom’s long-term contracts still active and under which deliveries continue to be made – all

via the Turkish Steam pipeline. This comprises term contracts for deliveries to Greece (3.0 Bcma between DEPA, Mytilineos, and Prometheus), North Macedonia (0.2 Bcma for MakPetrol), Serbia (1.5 Bcma for Srbijagas), Bosnia-Herzegovina (0.4 Bcma for Energoinvest), Hungary (6.5 Bcma for MVM), and Slovakia (3.5 Bcma for SPP).”²²

In July 2025 the European Commission drafted a new legislative proposal to phase out Russian gas from the EU by 2028. This proposal is the REPower EU Roadmap, and it is expected to be approved by the end of 2025²³ According to this Roadmap the Russian gas is to be phased out from European (EU27) supply from 2027. This includes Russian pipeline gas and LNG as well. In our modelling we included the implementation of the Roadmap into our assumptions. However, the Russian long term contract gas deliveries to non-EU countries (BA, RS and MK) via Turk Stream and Bulgaria is left unchanged.

4.2. ELECTRICITY MARKET MODELLING

4.2.1. COAL PRICE

Coal prices²⁴ have experienced very high volatility in recent years, with particularly sharp fluctuations observed during 2021–2023. This period was marked by strong correlation with gas prices, and in the past year coal traded in the elevated range of 100–150 \$/t, significantly above earlier levels. Looking ahead, the expected price trajectory is derived through a regression model in which REKK’s reference gas price serves as the main explanatory variable. Based on this approach, coal prices are projected to follow a slightly decreasing trend between 2027 and 2040, stabilizing around an average of 100 \$/t over the long term.

Table 8.
Russian long-term
CONTRACTS still
delivered in July 2025
Source: OIES Quarterly gas
review issue 29 2025

	ACQ bcm	Expiry
RU-BA	0.4	yearly renewed
RU-GR	3	2025
RU-HU	4.5-6.5	2036
RU-MK	0.2	2027
RU-RS	1.5	yearly renewed
RU-SK	3.5	2027
TOTAL	13.1-15.1	-

²¹ OIES Quarterly gas review issue 29 2025 July

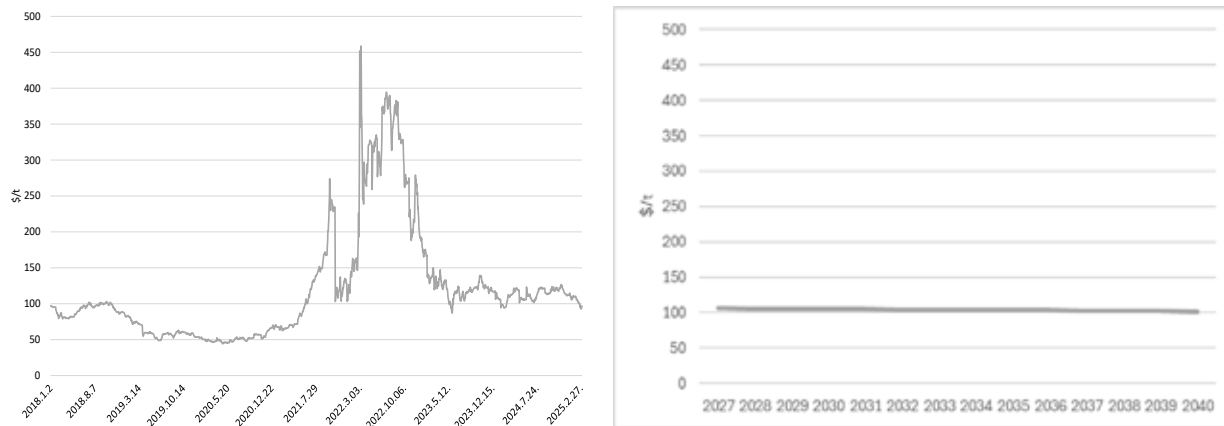
²² Jack Sharples (2025): [No Way Back? Challenges to Russian Pipeline Gas in Europe Make Near-Term Rebound Unlikely](#)

²³ [COMMUNICATION FROM THE COMMISSION TO THE EUROPEAN PARLIAMENT, THE COUNCIL, THE EUROPEAN ECONOMIC AND SOCIAL COMMITTEE AND THE COMMITTEE OF THE REGIONS Roadmap towards ending Russian energy imports COM/2025/440 final/2](#)

²⁴ These are the coal prices which coal-fired power plants use in Europe, for lignite fired power plants (such as the North Macedonian ones) a country specific lignite price is used which is for North Macedonia 1.4 EUR/GJ.

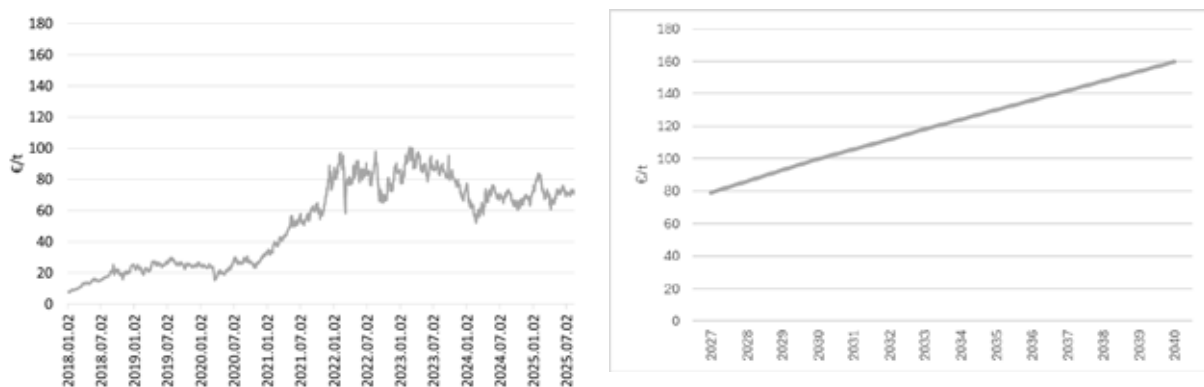
Figure 6.

Historical (left) and future (right) coal prices, USD/t

Source: Historical data: Marketwatch²⁵, Forecast: REKK's regression calculation

4.2.2. CO₂ PRICE

Since the beginning of 2022, the EUA price has fluctuated within a range of 60 to 100 EUR/t. Forecasts from different institutions support an upward trend: the IEA World Energy Outlook (2024)²⁶ projects 127–131 EUR/t in 2030 and 141–193 EUR/t in 2040; the European Commission's proposal for NECP planning (end of 2022) estimates 94 EUR/t in both 2025 and 2030, and 100–290 EUR/t by 2040; while the EC's 2040 90% assessment (February 2024)²⁷ anticipates an even higher range of 160–290 EUR/t by 2040. Together, these projections highlight a strong expectation of rising EUA prices in the coming decades. In the modelling a synthesis pathway created by REKK is used in which prices are expected to rise significantly, surpassing 100 EUR/t by 2030 and exceeding 150 EUR/t by 2040.

Figure 7.Historical (left) and future (right) CO₂ prices, EUR/tSource: Historical data: ICE based on Ember²⁸, Forecast: REKK's own estimation based on the estimations of IEA and EC

²⁵ <https://www.marketwatch.com/investing/future/mtfc00/charts>

²⁶ <https://www.iea.org/reports/world-energy-outlook-2024>

²⁷ <https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex-%3A52024SC0063&utm>

²⁸ <https://www.marketwatch.com/investing/future/mtfc00/charts>

Figure 8.
Gas prices in North Macedonia and neighbouring countries under reference gas prices, 2027-2040

Source: REKK modelling

Gas prices-REF (EUR/MWh)	2027	2030	2035	2040
MK	38.1	39.7	38.5	36.1
GR	37.4	38.1	36.8	34.4
BG	38.7	39.5	38.1	35.8
RS	40.1	40.0	38.6	37

Figure 9.
Gas prices in North Macedonia and neighbouring countries under Low gas prices, 2027-2040

Source: REKK modelling

Gas prices-REF (EUR/MWh)	2027	2030	2035	2040
MK	19.4	21.4	20.2	18.4
GR	18.8	19.6	18.6	16.7
BG	19.9	21.2	19.8	18.1
RS	21.3	22.5	20.9	19.3

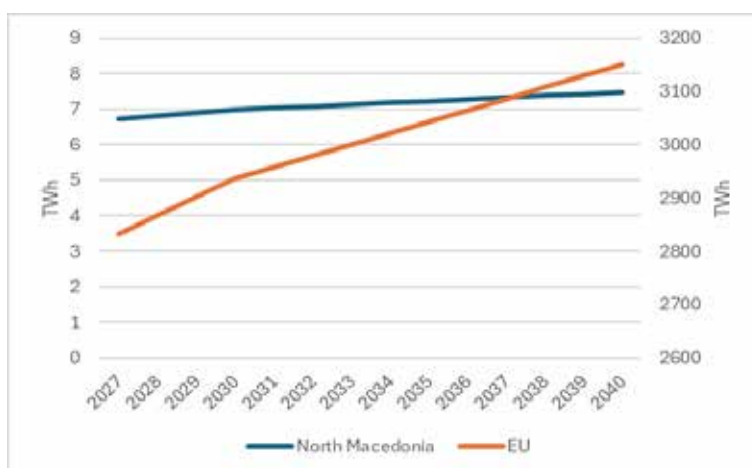
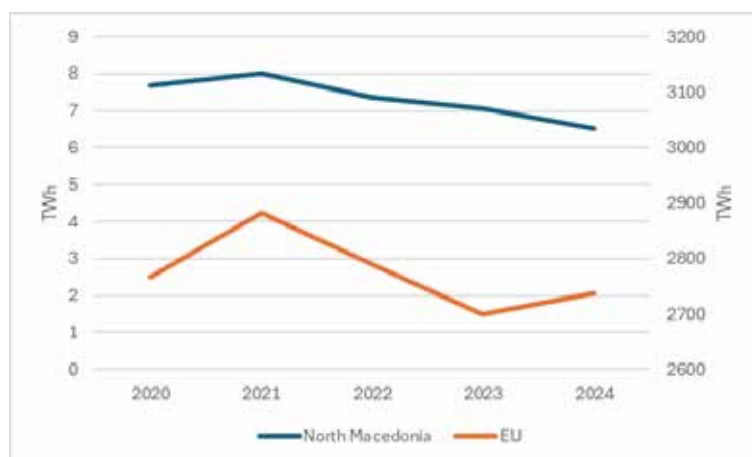
4.2.4. ELECTRICITY DEMAND IN NORTH MACEDONIA

Since 2021, electricity consumption in North Macedonia has shown a continuous decline, falling from 8 TWh to around 6.5 TWh, while EU27 consumption has largely stagnated, fluctuating between 2,700 and 2,850 TWh in the 2020-2024 period. Looking ahead, the World Bank projects North Macedonian demand to recover, reaching 7–8 TWh by 2030 and 8–9 TWh by 2040, depending on their scenarios. However, REKK offers a more cautious outlook, noting that the impact of energy efficiency measures has often been underestimated in past forecasts. REKK’s prognosis relies on 2024 actual values, adjusted using the European Commission’s “Fit for 55” modelling growth rates²⁹, resulting in a more conservative trajectory of future electricity consumption.

Figure 10.

Historical (up) and future (down) electricity demand in north macedonia and the EU27, TWh/year

Source: European Commissions’s Policy Scenarios for Green Deal



²⁹ Source: https://energy.ec.europa.eu/data-and-analysis/energy-modelling/policy-scenarios-delivering-european-green-deal_en

4.2.5. INTERCONNECTORS

Interconnector capacities of North Macedonia (and other countries as well) are based on REKK's own data collection, supplemented with the data of ENTSO-E TYNDP 2024 reference grid map³⁰. Projections of future capacities are aligned with ENTSO-E TYNDP 2024 planned projects³¹, ensuring consistency with officially documented development pathways.

Table 9. Existing and planned interconnector capacities in North Macedonia, NTC (MW)
Source: ENTSO-E TYNDP 2024

Status	From (A)	To (B)	NTC A-B (MW)	NTC B-A (MW)	Commissioning date
Existing	BG	MK	400	400	in operation
Existing	KO	MK	280	320	in operation
Existing	GR	MK	850	1100	in operation
Existing	RS	MK	480	460	in operation
Planned	AL	MK	500	500	2026
Planned	GR	MK	500	500	2036

Based on ENTSO-E there are two new projects expected to be commissioned in North Macedonia, the Bitola-Elbasan interconnector connecting the country to Albania and a future planned interconnector between Greece and North Macedonia in the mid-2030s. In the modelling the completion of both new lines is considered.

4.2.6. INSTALLED POWER PLANT CAPACITIES IN NORTH MACEDONIA

Installed fossil power plant capacities for the EU-27 rely on Global Energy Monitor's³² and Beyond Fossil Fuel's³³ projections, complemented by REKK's country-specific data collection. Renewable capacity expansion is primarily based on the National Energy and Climate Plans (NECPs)³⁴, with an ad-

justment applied to wind capacity, assuming 80% realization, as compared to actual implementation the targets seem overoptimistic.

In the case of North Macedonia, the data source was Eco-Svest's expert data collection, with no additional fossil capacity expansion considered beyond the planned CCGTs. In the modelling 300 MW capacity was assumed for Bitola and 800 MW for the Negotino power plant. For renewables, the list-

ed PV and wind projects were further supplemented by applying a region-specific capacity growth rate to reflect realistic development trends, especially post 2030.

Figure 11 summarizes the current and future capacity composition of EU (left) and North Macedonia (right). For North Macedonia, a separate chart is provided for the case when the Bitola and Negotino projects are completed, and another for the case of non-completion.

³⁰ <https://eepublicdownloads.blob.core.windows.net/public-cdn-container/tyndp-documents/TYNDP2024/foropinion/StartingGrid2030.xlsx>

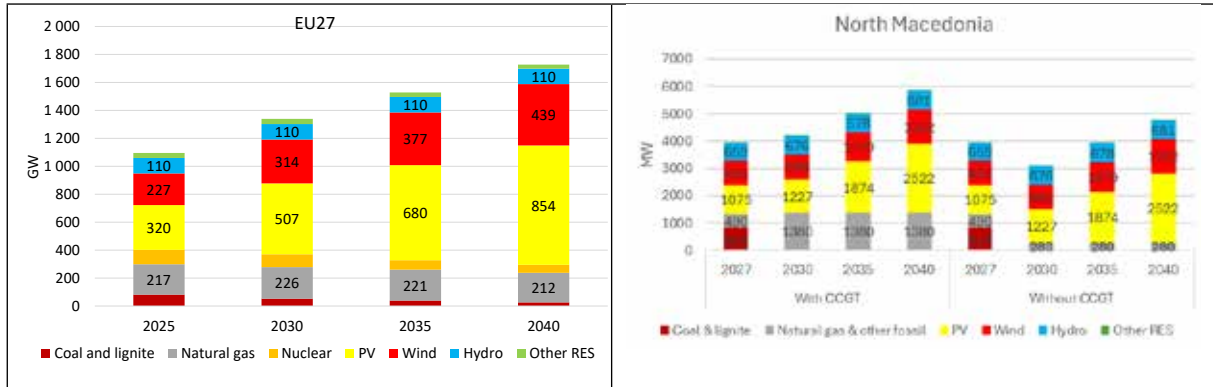
³¹ <https://tyndp2024.entsoe.eu/projects-map/transmission>

³² <https://globalenergymonitor.org/>

³³ <https://beyondfossilfuels.org/gas-tracker-tab/>

³⁴ https://commission.europa.eu/energy-climate-change-environment/implementation-eu-countries/energy-and-climate-governance-and-reporting/national-energy-and-climate-plans_en

Figure 11.
Installed power plant capacities in EU27 and North Macedonia to 2040, MW
 Source: REKK's own data collection based on Global Energy Monitor & Beyond Fossil Fuels



4.3. CCGT PLANS IN THE BALKAN REGION (OUTSIDE NORTH MACEDONIA)

The future of gas-fired power plant investments is very uncertain. Many countries in Europe and the Balkan region have significant capacity expansion plans for gas power plants; however, earlier REKK modelling showed that if all the planned power plants were completed, the vast majority of them would not be able to operate profitably (Szabó et al., 2025)³⁵. It can be argued that the new capacities are required to enable operation based on green hydrogen; however, this transition, due to the potentially limited green hydrogen supply, also does not seem economically and technically feasible in the near future. For the modelling exercise, we do not consider the use of green hydrogen as a fuel for gas power plants. The model can only consider plants operating entirely on hydrogen, not blends of natural gas and hydrogen. A similar analysis was carried out by REKK for the Balkan region³⁶, which examined the impact of hydrogen-based operation. It concluded that even if green hydrogen were available in sufficient quantities, the fuel cost would be much higher than that of natural gas, so producers would only adopt this option if required by regulation. In such a case, however, there would be serious concerns regarding profitability.

In this analysis, we considered two main scenarios regarding new gas power plant deployments (with gas as primary fuel). In the Reference scenario, only those future power plants are included in the system which are either under construction or in a relatively well-advanced stage, progressing continuously toward completion. To minimize biases in determining which plant belongs to this advanced category we relied on most recently updated investment tracker databases, provided and expert judgement and cross checked our project collection with other local experts in North Macedonia and the region, who follow the projects closely. In the high CCGT scenario, most announced plans (except those that have stalled for a long time) are considered.

Table 10 summarises the modelled capacities in both cases. The first column shows the existing capacities, the second one the additional capacities relative to the 2025 state in the Reference scenario, while the third column shows those in the high CCGT scenario.

³⁵ https://rekk.hu/downloads/events/4_SeieiAdrienn_V4%20conference.pdf

³⁶ https://rekk.hu/downloads/projects/REKK_Technical_Report_GasPP_final2.pdf

Table 10.
Planned gas capacities in the Balkan region (Outside North Macedonia)

Source: REKK's own categorisation based on Global Energy Monitor and Beyond Fossil Fuels databases & national sources

	Existing gas capacities - 2025 (MW)	New capacities - 2030 (MW)		New plants in REF	New plants in CCGT
		REF	CCGT		
Albania	0	0	170		Roskovec
Bosnia	0	0	0		
Bulgaria	1041	0	0		
Croatia	947	0	983		Legard Hybrid project, Crodux Slavon-ski Brod I-II.
Greece	6270	2692	3352	Larissa, Alexandroupolis, Komitini	Thessaloniki II, Ptole-maida
Hungary	3774	650	1650	Mátra	Tisza I-II
Kosovo	0	0	0		
Moldova	0	0	0		
Montene-gro	0	0	440		Bar
Romania	3074	2650	4825	Iernut, Chimcomplex, Chiech Soda, Craiova 2, Grosavesti, Bucharest Sud 8, Progresu, Bucharest Titan, Pa-las, Mintia Phase I	Turceni, Isalnita I-II, Mintia phase II
Serbia	549	0	500		Nis
Slovenia	588	0	0		
Sum	16673	5992	11920		

As of 2025, the largest installed capacities are found in Greece (6,270 MW), Hungary (3,774 MW), and Romania (3,074 MW), followed by Croatia (947 MW), Bulgaria (1,041 MW), and Slovenia (588 MW). Other countries in the region — Albania, Bosnia, Kosovo, Moldova, and Montenegro — have no existing gas-fired capacity at this point, with Serbia hosting a smaller base of 549 MW. In total, existing capacity across the region amounts to 16,673 MW.

Looking ahead to 2030, planned new capacities show a significant regional expansion, though concentrated in just a few countries. Under the Ref-

erence scenario, a total of 5992 MW of additional capacity is expected, led by Romania (2,650 MW) and Greece (2,692 MW). Also significant expansions planned in Hungary (650 MW).

The CCGT scenario envisions a much larger build-out of 11,920 MW, again dominated by Romania with up to 4,825 MW, followed by Greece with 3,352 MW, Hungary with 1650 MW and Croatia with nearly 1,000 MW. Smaller expansions are foreseen in Montenegro (440 MW) and Serbia (500 MW), while Albania's Roskovec plant would contribute 170 MW.

5

RESULTS

5.1. GAS MARKET MODELLING

As lined out in Chapter 3, the utilisation and effects of the pipeline on the gas markets were assessed by modelling the pipeline ceteris paribus, i.e. adding the (i) GR-MK pipeline and (ii) the pipeline and the new CCGTs to a modelled base case without changing any other assumptions (e.g. European gas demand, availability of Russian gas, LNG market conditions, tariffs on infrastructure etc.).

5.1.1. PRICES

Effects of commissioning the GR-MK interconnector are limited to North Macedonia. (Figure 13) The pipeline creates competition to the existing BG-MK interconnector and has a price-decreasing effect of 1.5 EUR/MWh (~4%). The additional demand of CCGTs alleviates this effect to 0.4 EUR/MWh (1%). (Table 11, Figure 12)

Table 11. gas wholesale prices in North Macedonia in the base case, with the pipeline and with the CCGTs, EUR/MWh (JP=40, EU demand=REF)
Source: RKK modelling

EU demand	JP price	Base			Pipeline			Pipeline+CCGT		
		2030	2035	2040	2030	2035	2040	2030	2035	2040
ref	40	40.14	38.64	36.52	38.66	37.17	35.05	39.74	38.46	36.06

Figure 12. gas wholesale prices in North Macedonia in the base case, with the pipeline and with the CCGTs, EUR/MWh (JP=40, EU demand=REF)
Source: REKK modelling

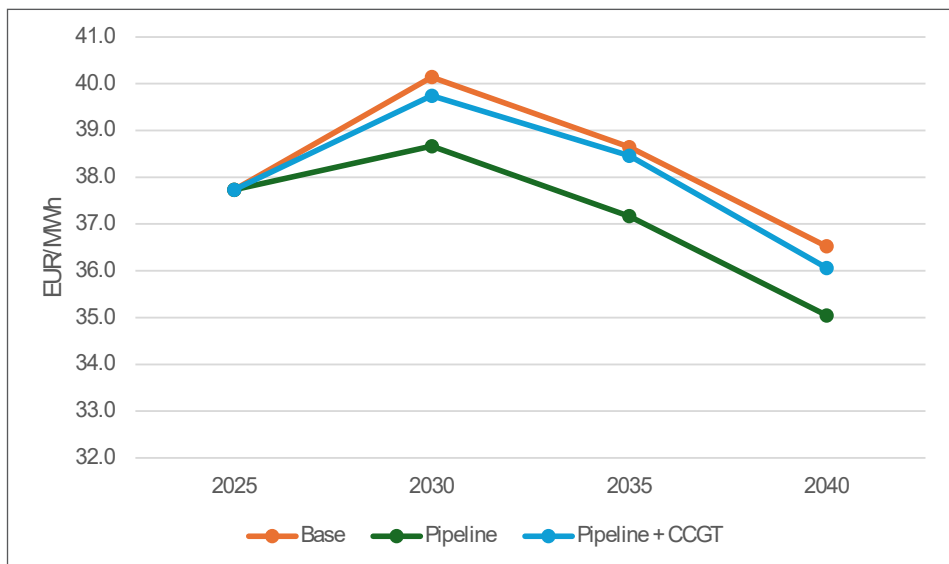
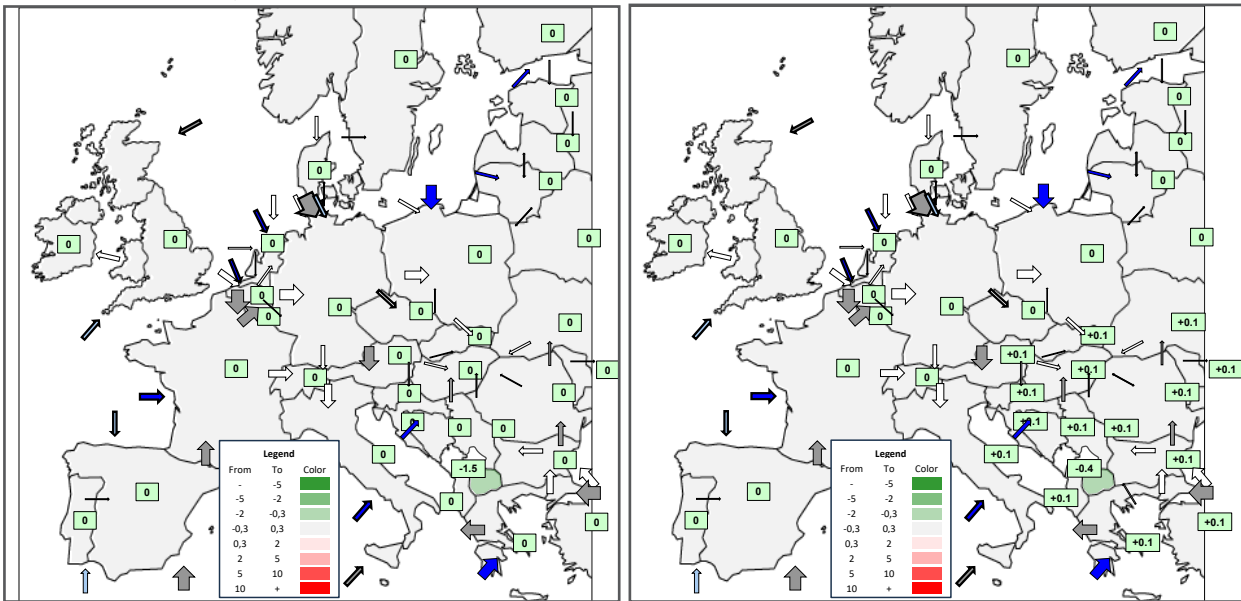


Figure 13. Price effect of GR-MK interconnector in 2030, EUR/MWh compared to the base case (JP=40 EUR/MWh, EU demand=REF)
Source: REKK modelling



5.1.2. GAS FLOWS

It is apparent that once the pipeline is commissioned, flows are redirected from the existing route to the newly commissioned one. With the CCGTs in operation, the pipeline runs at nearly full capacity, with additional utilisation of the existing BG-MK interconnector. (Table 12, Table 13)

As the pipeline is supplied from Greece, it is interesting to see what the sourcing of the gas is. To do so, the supply structure of Greece was compiled (including all interconnectors and LNG sources). If only the interconnector gets commissioned, the flows are redirected from the Greece-Bulgaria-North Macedonia route to the Greece-Bulgaria

route. The reason for that is that the tariff for the Greek route is more attractive. When additional CCGTs are added, the interconnector is run nearly at capacity.

Surprisingly, it is not LNG utilisation what is ramped up in 2030 and 2035. LNG terminals in Greece have already been running at capacity in our base case. For 2040, Greek LNG utilisation is increased by 7.5 TWh/year.

For 2030 and 2035, it is flows out of the Greek system which are reconfigured: less gas is transmitted to the Bulgarian network and to Italy via TAP. These volume reductions are the main sources of supply for the new interconnector. (Table 14)

Table 12. Pipeline flows and gas demand in North Macedonia, TWh/yr

	TWh/yr	Base			Pipeline			Pipeline+CCGT		
		2030	2035	2040	2030	2035	2040	2030	2035	2040
BG-MK		3.66	3.66	3.66	0.00	0.00	0.00	1.29	1.29	1.29
GR-MK		0.00	0.00	0.00	3.66	3.66	3.66	11.95	11.95	11.95
MK-GR		0	0	0	0	0	0	0	0	0
MK demand		3.66	3.66	3.66	3.66	3.66	3.66	13.23	13.24	13.24

Table 13. Pipeline utilisation and gas demand in North Macedonia, %

		Base			Pipeline			Pipeline+CCGT		
		2030	2035	2040	2030	2035	2040	2030	2035	2040
BG-MK		31%	31%	31%	0%	0%	0%	11%	11%	11%
GR-MK		0%	0%	0%	25%	25%	25%	82%	82%	82%
MK-GR		0%	0%	0%	0%	0%	0%	0%	0%	0%

Source: REKK modelling

Table 14.
Pipeline flows, LNG and demand change in Greece compared to the base case, TWh/yr

Source: REKK modelling. Δ refers to change compared to reference case.

	Pipeline			Pipeline+CCGT		
	2030	2035	2040	2030	2035	2040
Δ BG-GR	0.0	0.0	0.0	0.0	0.0	0.0
Δ IT-GR	0.0	0.0	0.0	0.0	0.0	0.0
Δ TR-GR	0.0	0.0	0.0	0.0	0.0	0.0
Δ MK-GR	0.0	0.0	0.0	0.0	0.0	0.0
Δ GR-AL	0.0	0.0	0.0	0.0	0.0	0.0
Δ GR-BG	-3.7	-3.7	-3.7	-10.4	-8w.9	-3.4
Δ GR-IT	0.0	0.0	0.0	-1.5	-2.8	-1.0
Δ GR-TR	0.0	0.0	0.0	0.0	0.0	0.0
Δ GR-MK	3.7	3.7	3.7	11.9	11.9	12.0
Δ LNG	0.0	0.0	0.0	0.0	0.2	7.5
Δ GR demand	0.0	0.0	0.0	0.0	0.0	0.0

5.1.3. SENSITIVITIES

Modelling sensitivities were performed for various market conditions: for the future LNG glut, over-supply of LNG capacities is expected to cause cheaper overall global price levels. Additionally to the reference case (JP= 40 EUR/MWh), global LNG price was considered at 20, 30, 50 and 60 EUR/MWh as well.

Besides the availability of LNG, main driver of the market outcomes is the level of European demand. Compared to the reference case, +15% and -15% of EU27 demand is modelled. For EU27, reference

demand means ~3 500 TWh/year gas consumption in 2023. High demand levels mean ~4 000 TWh/year, which corresponds to the EU27 gas demand before the energy crisis. Low demand shows an extreme with ~3 000 TWh/year.

With regard to price effects, results are robust to both the demand and global price sensitivities. The pipeline and the power plant investment has its effect limited to North Macedonia. If only the pipeline is commissioned, the price effect is 1.5 EUR/MWh. With additional CCGT demand, the effect drops to 0.3-0.5 EUR/MWh. (Table 15)

Table 15.
Price effect of the interconnector and the CCGTs in North Macedonia compared to the base case, EUR/MWh

Source: REKK modelling.

EU demand	JP price	Pipeline			Pipeline+CCGT		
		2030	2035	2040	2030	2035	2040
low	20	-1.48	-1.48	-1.22	-0.43	-0.15	-0.30
low	30	-1.48	-1.48	-1.39	-0.34	-0.34	-0.45
low	40	-1.48	-1.48	-1.35	-0.41	-0.34	-0.86
low	50	-1.48	-1.48	-0.44	-0.43	-0.47	-0.04
low	60	-1.48	-1.46	-0.48	-0.38	-0.50	-0.02
ref	20	-1.67	-1.48	-1.48	-0.39	-0.38	-0.04
ref	30	-1.48	-1.50	-1.48	-0.30	-0.24	-0.41
ref	40	-1.48	-1.48	-1.48	-0.40	-0.18	-0.46
ref	50	-1.48	-1.48	-1.48	-0.51	-0.34	-0.50
ref	60	-1.48	-1.48	-1.47	-0.43	-0.43	-0.48
high	20	-1.48	-1.76	-1.48	-0.52	-0.52	-0.46
high	30	-1.48	-1.55	-1.48	-0.52	-0.46	-0.36
high	40	-1.49	-1.48	-1.48	-0.52	-0.41	-0.26
high	50	-1.48	-1.48	-1.48	-0.38	-0.23	-0.43
high	60	-1.48	-1.48	-1.48	-0.38	-0.27	-0.51

Flow patterns and utilisation of infrastructure also shows the same picture: when only the pipeline is commissioned, all flows from the BG-MK interconnector are redirected to the new route. (Table 16)

If additional CCGTs are added to the Macedonian demand, the pipeline is used nearly at capacity, but the BG-MK route is also needed to meet the increased demand. (Table 17)

Table 16.
Annual flows on MK interconnectors with the GR-MK interconnector commissioned, TWh/yr

		Pipeline								
		2030			2035			2040		
EU demand	JP price	GR-MK	BG-MK	MK Demand	GR-MK	BG-MK	MK Demand	GR-MK	BG-MK	MK Demand
low	20	3.68	0.00	3.68	3.68	0.00	3.68	3.68	0.00	3.68
low	30	3.67	0.00	3.67	3.67	0.00	3.67	3.67	0.00	3.67
low	40	3.66	0.00	3.66	3.66	0.00	3.66	3.51	0.16	3.66
low	50	3.66	0.00	3.66	3.66	0.00	3.66	3.26	0.40	3.66
low	60	3.65	0.00	3.65	3.65	0.00	3.65	3.25	0.40	3.65
ref	20	3.67	0.00	3.67	3.67	0.00	3.67	3.68	0.00	3.68
ref	30	3.67	0.00	3.67	3.67	0.00	3.67	3.67	0.00	3.67
ref	40	3.66	0.00	3.66	3.66	0.00	3.66	3.66	0.00	3.66
ref	50	3.65	0.00	3.65	3.66	0.00	3.66	3.66	0.00	3.66
ref	60	3.65	0.00	3.65	3.65	0.00	3.65	3.65	0.00	3.65
high	20	3.59	0.00	3.59	3.67	0.00	3.67	3.68	0.00	3.68
high	30	3.59	0.00	3.59	3.67	0.00	3.67	3.67	0.00	3.67
high	40	3.59	0.00	3.59	3.66	0.00	3.66	3.66	0.00	3.66
high	50	3.59	0.00	3.59	3.65	0.00	3.65	3.66	0.00	3.66
high	60	3.59	0.00	3.59	3.65	0.00	3.65	3.65	0.00	3.65

Table 17.
Annual flows on MK interconnectors with the GR-MK interconnector and additional CCGTs commissioned, TWh/yr

		Pipeline + CCGT								
		2030			2035			2040		
EU demand	JP price	GR-MK	BG-MK	MK Demand	GR-MK	BG-MK	MK Demand	GR-MK	BG-MK	MK Demand
low	20	11.97	1.32	13.28	11.97	1.32	13.29	11.97	1.32	13.29
low	30	11.96	1.30	13.26	11.96	1.31	13.27	11.96	1.31	13.27
low	40	11.95	1.29	13.24	11.95	1.29	13.24	11.69	1.29	13.25
low	50	11.94	1.27	13.21	11.94	1.28	13.22	11.48	1.28	13.22
low	60	11.93	1.26	13.19	11.93	1.26	13.20	11.69	1.26	13.20
ref	20	11.96	1.32	13.28	11.96	1.32	13.28	11.97	1.32	13.29
ref	30	11.96	1.30	13.26	11.96	1.30	13.26	11.96	1.30	13.27
ref	40	11.95	1.29	13.23	11.95	1.29	13.24	11.95	1.29	13.24
ref	50	11.94	1.27	13.21	11.94	1.27	13.21	11.94	1.27	13.22
ref	60	11.93	1.25	13.18	11.93	1.26	13.19	11.93	1.26	13.19
high	20	11.83	1.11	12.94	11.96	1.32	13.28	11.97	1.32	13.29
high	30	11.83	1.11	12.94	11.95	1.30	13.26	11.96	1.30	13.26
high	40	11.83	1.11	12.94	11.95	1.29	13.23	11.95	1.29	13.24
high	50	11.83	1.11	12.94	11.94	1.27	13.21	11.94	1.27	13.22
high	60	11.83	1.11	12.94	11.93	1.25	13.18	11.93	1.25	13.19

5.2. ELECTRICITY MARKET MODELLING

5.2.1. ELECTRICITY PRICE IN NORTH MACEDONIA

The evolution of baseload electricity prices is summarised in Figure 14.

Peakload³⁷ price trends are captured in Figure 15.

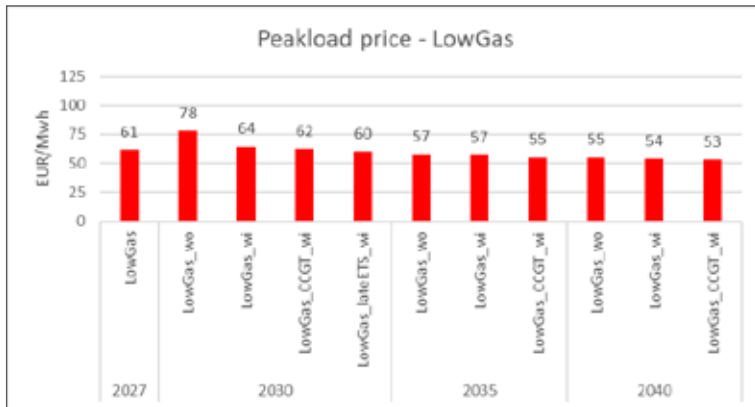
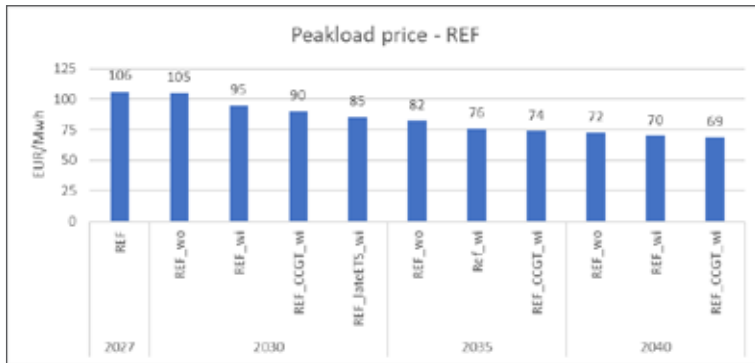
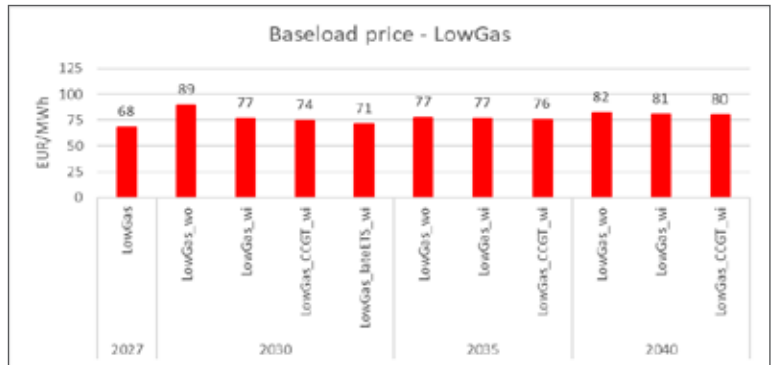
Figure 14. Evolution of North macedonian baseload prices in the reference (UP) and Lowgas (DoWN) scenarios, 2027-2040

Source: REKK modelling



Figure 15. Evolution of North macedonian Peakload prices in the reference (UP) and Lowgas (DOWN) scenarios, 2027-2040

Source: REKK modelling



In the LowGas environment, electricity prices are projected to be substantially lower, ranging between 70 and 90 EUR/MWh, compared to 100–120 EUR/MWh in the Reference scenario. This difference is primarily driven by the fact that gas-based electricity production is significantly cheaper in LowGas. Peakload prices remain consistently below baseload prices under both gas prices due to the constantly increasing amount of solar generation in both North Macedonia and Europe during daytime peak periods.

³⁷ Peak load period only considers weekdays between 8 AM and 8 PM. Traditionally this period was associated with higher prices, because of higher electricity demand.

The completion of new CCGTs plays a notable role in moderating electricity prices, however their relevance is diminishing over time. In the Reference scenario new North Macedonian CCGTs reduce electricity prices by 8 EUR/MWh in 2030, 5 EUR/MWh in 2035, and 2 EUR/MWh in 2040. In the Low-Gas scenario, the effect is more pronounced initially, with a reduction of 14 EUR/MWh in 2030, but it diminishes rapidly to less than 1 EUR/MWh in 2035 and 1 EUR/MWh in 2040.

At the regional level, the deployment of additional CCGTs beyond North Macedonia contributes to further price reductions. However, the magnitude of this effect also diminishes over time, with estimated reductions of 3–5 EUR/MWh in 2030, 1–2 EUR/MWh in 2035, and approximately 1 EUR/MWh in 2040 relative to the state when only 6 GW capacity is installed regionally. While CCGT construction in the country and the broader region can provide near-term price decrease in North Macedonia, the

long-term impact is constrained by both fuel costs (increasing EUA prices) and increasing integration of renewable generation, which displaces gas-fired power plants in more and more hours throughout the year.

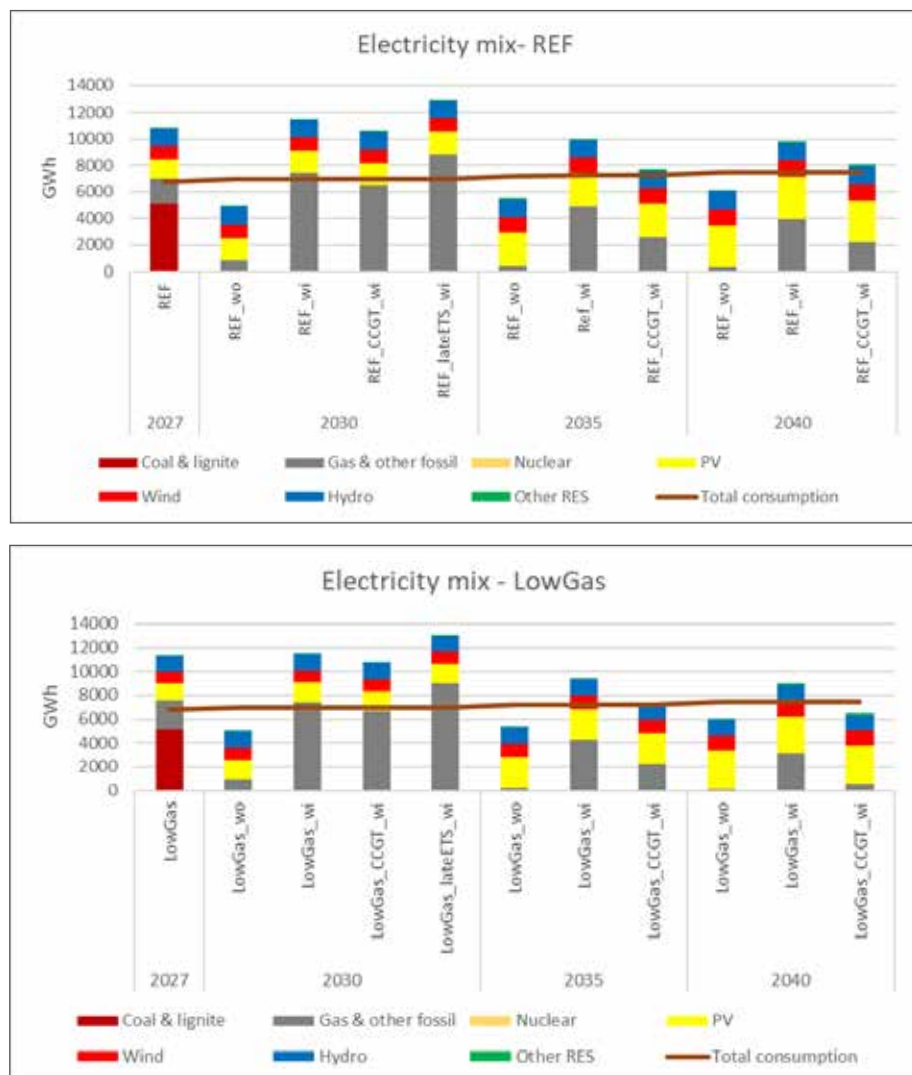
Participation of WB6 countries in the EU ETS system starting in 2030 results in electricity price increase in both scenarios compared to 2027. After 2030, the Reference scenario exhibits a slightly decreasing price trend, whereas the LowGas scenario shows a modestly increasing trend. Delayed ETS participation however can lead to significantly lower electricity prices in 2030, the difference amounts to 6–10 EUR/MWh.

5.2.2. ELECTRICITY MIX OF NORTH MACEDONIA

Figure 16 shows the electricity mix of North Macedonia under Reference and LowGas prices in all scenarios.

Figure 16. Electricity mix of north macedonia under reference (TOP) and LowGas (BOTTOM) gas price assumptions, 2027-2040

Source: REKK modelling



North Macedonia's electricity system remains secure under all examined scenarios, meaning that there is no occurrence of energy not supplied even if Bitola and Negotino are not completed. This means that the completion of the two new CCGTs is not a necessity for the secure operation of North Macedonian wholesale markets.³⁸ However, the country's reliance on electricity imports increases substantially if the planned CCGT power plants are not completed. In this case, the net electricity import ratio is expected to rise to approximately to 28–32% in 2030 and remains around 25% in 2040, compared to the current level of around 11%. This higher import share however does not result in security of supply issues as similarly to many European countries North Macedonia can safely operate with a high import ration based on the model results.

If the planned CCGT power plants are successfully completed, North Macedonia's position in the regional electricity market changes significantly. The additional generation capacity enables the country to become a net exporter of electricity, particularly in 2030, when RES deployment in the region is only modest.

Comparing the two gas price scenarios, it is evident that gas-based electricity generation is higher in the Reference case than in the LowGas case. At first glance, one might expect that lower gas prices would lead to higher production; however, this is not the case. The reason is that gas prices are lower across all countries, meaning that the main determinant of production becomes the relative gas price between countries rather than the absolute price level. In the LowGas environment, the relative position of both North Macedonia compared to the surrounding region and the WB6 region compared to Central Europe worsens. As a result, gas-based electricity production in North Macedonia is lower in this scenario compared to the Reference setup.

Independent from gas prices other regional CCGT projects do not pose very strong competition to North Macedonia in 2030 (but still decrease domestic gas-based production), however their influence increases considerably in the following years. As renewable energy sources expand rapidly across

Europe and the region, gas power plants in general will be needed less, so operating power plants compete more strongly.

Delayed entry of WB6 countries into the EU ETS has a notable impact on North Macedonia's generation mix. Postponing ETS participation leads to significantly higher gas-based electricity production in 2030, as the absence of carbon pricing temporarily improves the competitiveness of gas-fired generation, and no carbon price has to be paid when the power plant produces for the domestic market. Naturally it will result in higher emissions for North Macedonia as it is described in detail in Section 5.2.4.

5.2.3. UTILIZATION AND PROFITABILITY OF PLANNED NORTH MACEDONIAN GAS POWER PLANTS

The utilisation of Bitola and Negotino CCGTs is summarised in Figure 20 for both gas price scenarios. The figure shows that the utilisation of the two power plants is very similar, because in the modelling they have the exact same technology (CCGT completed in 2030) and facing the same gas price. Thus, operational differences only come from size difference which is relevant in only a small portion of hours.

In 2030, the newly established power plants reach an exceptionally high product market utilisation of around 73%, in both gas price scenarios. This indicates that, at the beginning of their operation, these new units are able to operate close to their economic potential.

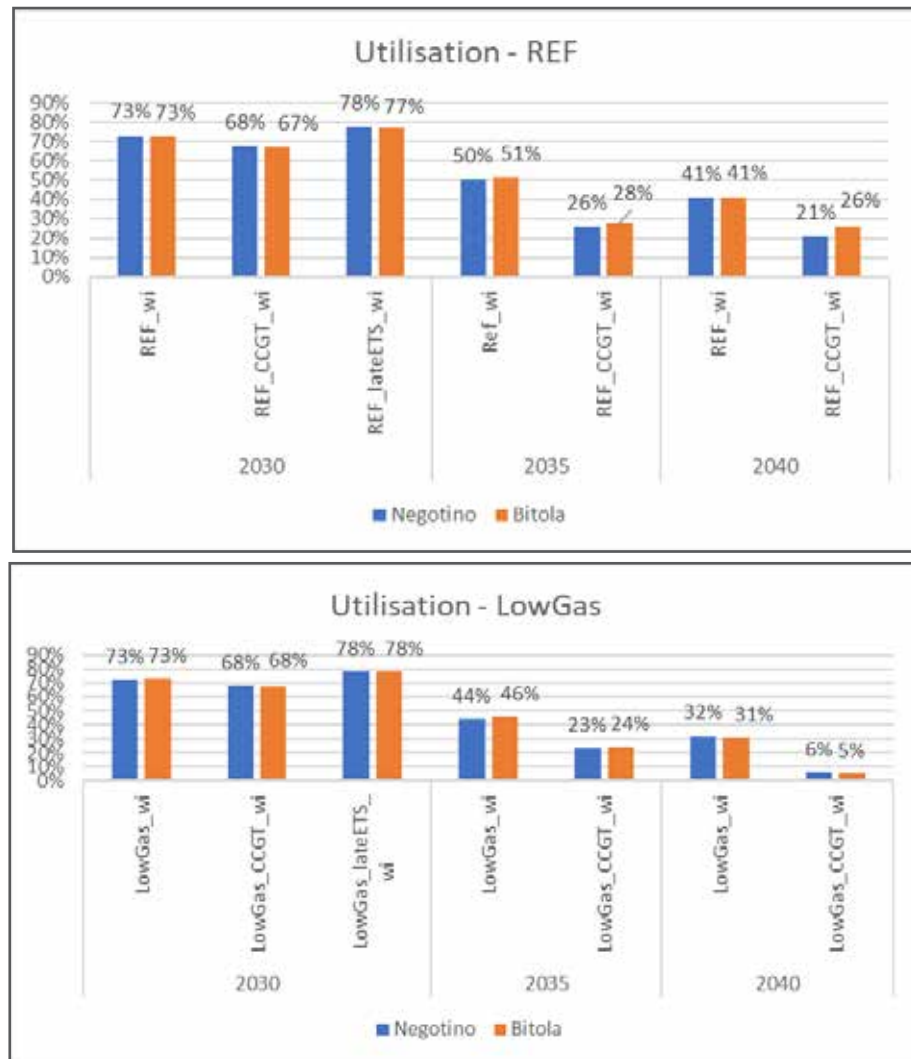
However, this initially high utilisation declines over time. By 2040, the utilisation of the new combined-cycle gas turbines (CCGTs) is projected to fall to 41% in the Reference (REF) scenario and to 32–31% in the LowGas scenario, even in the absence of additional CCGT capacity entering the regional market. This reduction reflects the increasing share of renewable generation, and the increasing costs of gas-fired electricity generation.

The decline becomes even more pronounced if other CCGTs are built in the region. In such a case, utilisation rates of the new plants are expected to decrease to 26–28% by 2035 and to 21–26% by 2040 in the REF scenario. Under the LowGas sce-

³⁸ The plants might be needed for reserve purposes, but those markets are not analysed in this report.

Figure 17.
Utilisation of Bitola
and negotiNo CCGTs
in Reference (up) and
lowgas (down) scenarios,
2030-2040

Source: REKK modelling



nario, utilisation falls even further—to 23–24% in 2035 and to as little as 5–6% by 2040. These very low values are not able to ensure economic viability in the long run.

To assess profitability, REKK performed additional calculations comparing the yearly profits of the two new gas power plants with their annualised investment costs³⁹. Over the expected lifetime of the plants—approximately 25 years without major renovation—the annual profits should exceed the annualised investment costs for the investment to be considered financially viable. In this calculation only the profits of the first 10 years can be considered, as the modelling period ends in 2040.

The variables required for calculating yearly profits are direct outputs of the EPMM model, while determining investment costs requires additional assumptions. These include the estimated capital costs of the two new power plants and the Weighted Average Cost of Capital (WACC) used for annualization. The assumptions applied in these calculations are summarised in Table 18.

³⁹ The annualised investment cost is the total capital expenditure of a project spread evenly over its economic lifetime, expressed as an equivalent yearly cost.

Table 18.
Applied assumptions
for annualised
investment cost
calculations

Variable	Data	Source
Investment cost of Bitola	Low: 300 million EUR Medium: 350 million EUR High 400 million EUR	European Commission & Government of North Macedonia. (2024). <i>Annex 2 – RGF indicative list of investment projects</i> ⁴⁰
Investment cost of Negotino	Low: 640 million EUR Medium: 747 million EUR High: 853 million EUR	Estimated with an economy of scale factor of 80%.
Real WACC	5.2%	Bedoya-Cadavid, J. A., Lanzas-Duque, Á. M., & Salazar, H. (2023). WACC for electric power transmission system operators: The case of Colombia. <i>Energies</i> , 16(2), 964 ⁴¹

Sources indicate that the investment cost of the Bitola power plant is estimated to range between 300 and 400 million Euros. Based on this, three investment cost scenarios were defined: a low-cost case at 300 million Euros, a medium-cost case at 350 million Euros, and a high-cost case at 400 million Euros.

For the Negotino project, REKK could not identify reliable information on investment costs. In previous years, the planned capacity of the project was between 300 and 500 MW, but in 2025 the design was revised, increasing the planned capacity to 800 MW. Since no cost estimate corresponding to this new size was available, REKK estimated the investment cost based on the Bitola values. It was assumed that the investment cost per MW for an 800 MW power plant is approximately 80% of that for a 300 MW plant, reflecting the economies of scale associated with larger installations.⁴² This calculation was made fall all three investment cost scenarios.

According to Bedoya et al. (2023)⁴³, the North Macedonian Transmission System Operator (TSO) operates with a real WACC of 5.2%. Although power plant projects typically face higher WACC values due to greater investment risks, it was assumed that the new CCGTs will likely receive governmental backing, which lowers their risk. Therefore, for the purposes of this profitability assessment, applying the TSO’s WACC of 5.2% was considered an appropriate and reasonable assumption.

The annualised investment cost per kWh was calculated by multiplying the total investment cost by the annuity factor and dividing the result by the installed capacity.

Figure 18 shows the results of the profitability calculations for Bitola power plant in the Reference and LowGas scenarios. The blue bars show the yearly profit, while the lines represent the annualised investment costs in the three costs scenarios.

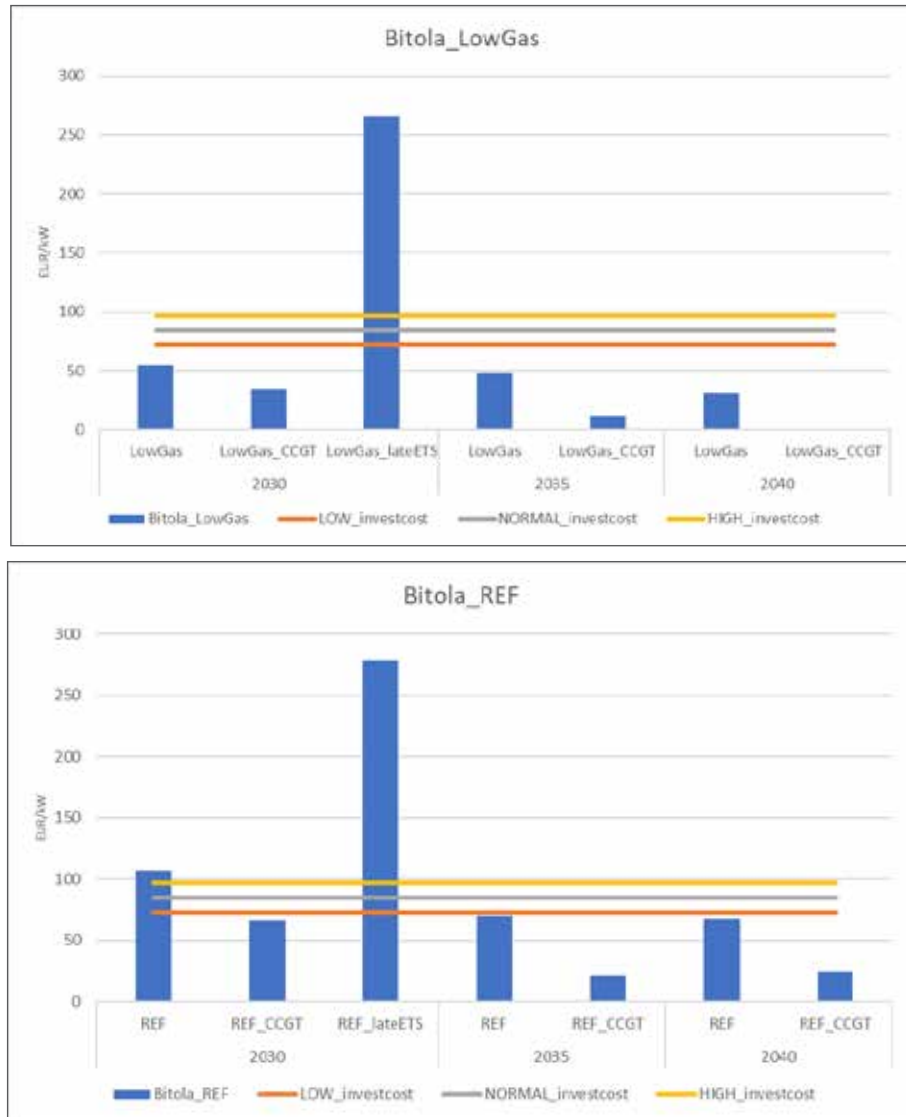
⁴⁰ <https://reform-monitor.org/documents/north-macedonia-annex-2-indicative-list-of-investment-projects/>

⁴¹ <https://www.mdpi.com/1996-1073/16/2/964>

⁴² Some costs elements are not related to size, thus if larger projects are built the capital costs per MW tends to be lower.

⁴³ Bedoya-Cadavid, J. A., Lanzas-Duque, Á. M., & Salazar, H. (2023). WACC for electric power transmission system operators: The case of Colombia. *Energies*, 16(2), 964

Figure 18.
 Profitability calculation
 for bitola CCGT in
 reference (Up) and
 Lowgas Down) scenArios,
 2030-2040
 Source: REKK modelling



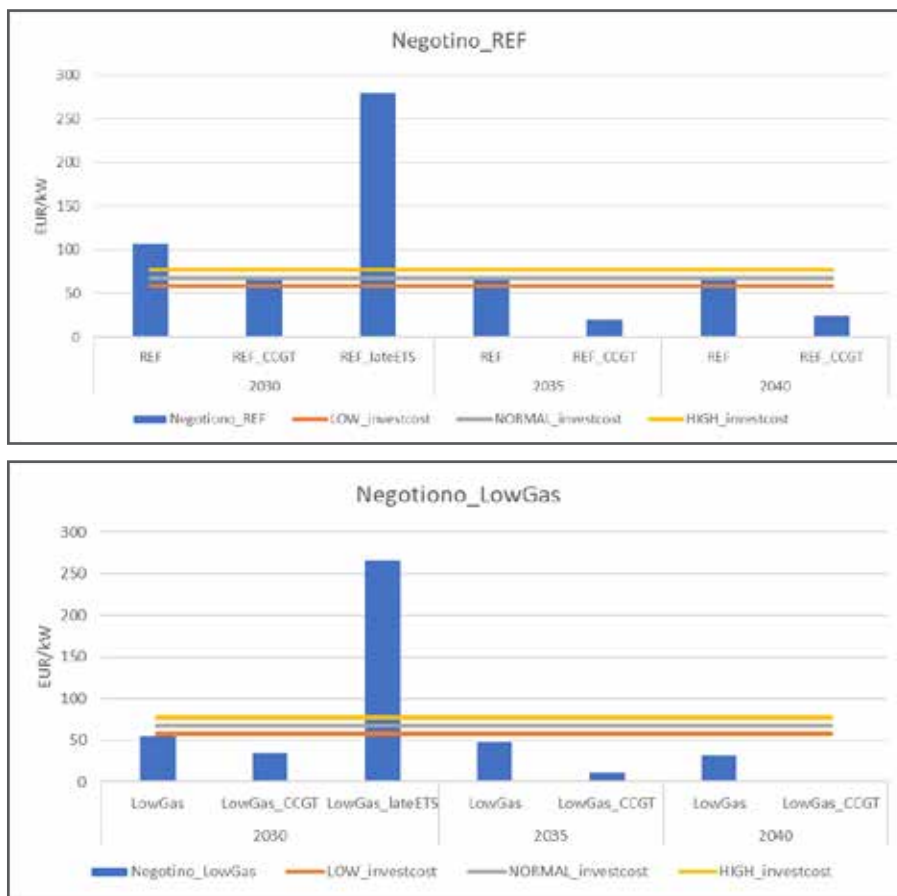
The results show that the Bitola project is not financially viable if it is developed simultaneously with the Negotino project. The only potential exception could occur if the WB6 countries remain outside the ETS system for an extended period as in 2030 the power plant realises very large profit in this

scenario. However, confirming this would require more detailed modelling for the later years without ETS participation. Since ETS participation is closely connected with EU accession, delays would imply consequences far beyond this investment, which are beyond the scope of the model.

For Negotino the results are presented in Figure 19

Figure 19. Profitability calculation for Negotino CCGT in reference (Up) and Lowgas (Down) scenarios, 2030-2040

Source: REKK modelling



The Negotino project does not appear to be financially viable under the LowGas scenario if it is constructed and operated in parallel with the Bitola project. In this case, the lower utilisation of the power plant leads to insufficient profits to cover investment costs.

However, under the Reference (REF) scenario, the financial outlook for Negotino is better, provided that a number of key conditions are met. First, the total investment cost should remain within a realistic and controlled range, not exceeding approximately 750 million Euro. Second, the power plant's utilisation rate should not experience a substantial decline after 2040, as maintaining relatively stable operation levels over its expected lifetime is essential for long-term profitability. Third, the regional market environment should remain relatively stable, without a major expansion of new CCGT capacities that would intensify competition and drive down utilisation for all gas-fired plants (including Negotino). If these conditions are met, the operation of Negotino power plant can be economically viable, within the modelled framework.

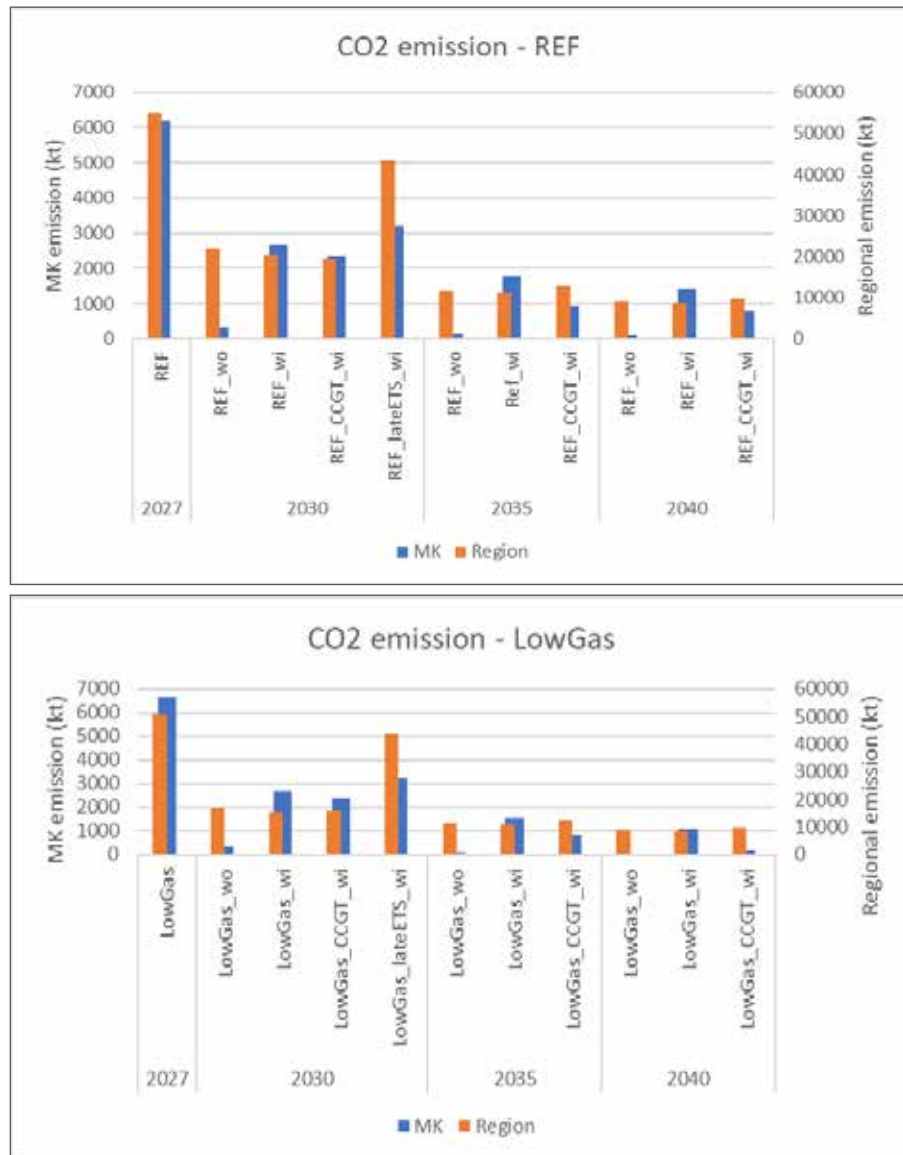
Similar to the findings for the Bitola power plant, the profitability of the Negotino project could increase substantially if the WB6 countries postpone their entry into the ETS. However this is closely connected to the countries' EU accession and cannot be considered in isolation. This effect is largely independent of gas price developments.

5.2.4. CO₂ EMISSION CHANGES

When analysing CO₂ emissions, two important factors must be taken into account: first, the emissions originating within North Macedonia, and second, those occurring in the immediate vicinity of the country. The latter aspect is particularly relevant, as the completion of the Bitola and Negotino power plants may also influence regional emission levels. For the purpose of this analysis, the "close proximity" includes the WB6 countries, supplemented by North Macedonia's neighbouring countries that are not part of this group—namely Bulgaria and Greece. Figure 20 summarises both the domestic emissions of North Macedonia and the emissions within the close proximity.

Figure 20. modelled CO₂ emissions in north Macedonia and close proximity under reference (Up) and lowgas scenarios (Down), 2027-2040

Source: REKK modelling



In the LowGas scenario, total CO₂ emissions are lower both across the region and within North Macedonia compared to the Reference scenario. At the regional level, this difference arises because lower gas prices lead to greater substitution of coal-based generation with gas-fired production, resulting in a cleaner overall generation mix. In North Macedonia, the utilisation of the two new power plants is lower under the LowGas scenario, and therefore, the associated emissions are also reduced.

The completion of North Macedonia's CCGT power plants results in a significant increase in domestic emissions. Additional CO₂ emissions are estimated to exceed 2,500 kilotonnes in 2030, decline to around 1,500–2,000 kilotonnes by 2035, and further decrease to approximately 600–900 kilotonnes by 2040 depending on the gas price. The decline over time reflects the gradually lower utilisation of gas-fired units.

At the regional level, however, the construction of new CCGTs in North Macedonia leads to an overall reduction in emissions. Depending on the year and the scenario, regional CO₂ emissions decrease by approximately 500–2,000 kilotonnes, as efficient gas generation in North Macedonia substitutes more carbon-intensive coal-based production in other countries. This means that with respect to total emissions the projects seem beneficial for the region, but this could not be counted towards North Macedonia's emissions reduction commitments.

Assuming a larger deployment of CCGTs in Balkan countries leads to mixed conclusions regarding emissions. In the Reference scenario for 2030, higher CCGT deployment outside North Macedonia results in even lower emissions compared to a more modest CCGT expansion pathway. However, in all other examined years and scenarios, a larger

CCGT expansion in the Balkans tends to increase emissions relative to the moderate expansion pathway, meaning that too much new gas-fired capacity indeed increases emissions.

A delayed entry of the WB6 countries into the EU ETS would drastically increase emissions in both the close proximity and North Macedonia. The absence of carbon pricing incentives in this case maintains the competitiveness of fossil-fuel-based generation, slowing the transition toward cleaner energy sources.

6

CONCLUSIONS AND RECOMMENDATIONS

RESULTS OF THE GAS MARKET MODELLING:

The new GR-MK pipeline provides a second supply route for Macedonia on the gas markets and indeed provides access to alternative sources. However, it has a negligible impact on the regional gas market prices' development. This is a robust result despite that MK consumption doubled since 2014 and is about to triple from 2024 to 2030 if all CCGTs are built and run. The reason for that is that the highest estimates are at a yearly 1.3 bcm consumption, that is still negligible from the European gas market point of view.

The European gas market is well supplied by diverse sources and especially the global LNG supply increase by 2027 will provide sufficient sources to Europe even in a case when Russian gas is phased out from the EU gas mix. With the new interconnector in place, the North Macedonian gas market supply is ensured and is more resilient to supply shocks. The potential decrease of gas purchases from Europe from 2027 might result in surplus gas of Russian source that can be sourced via TurkStream. We did not consider this possibility of additional spot Russian sales in the modelling, but if that happens that would put a downward pressure on gas prices in North Macedonia.

Modelling results show that the GR-MK pipeline and the new CCGT power plant investment have its effect limited to North Macedonia. If only the

pipeline is commissioned, the price effect is **1.5 EUR/MWh decrease** compared to the base case. With additional CCGT demand, the effect drops to 0.3-0.5 EUR/MWh decrease. In the current price environment (30-40 EUR/MWh) it is between 1-5% change. Regarding price effects, results are robust to both the demand and global price sensitivities. It is worth noting, that in case of assuming 15% demand increase to Europe, the prices could dramatically increase throughout entire Europe. This result however should be read with caution. In our modelling we did not allow for a high flexibility for the consumers. Assuming therefore a high demand when price levels go high is contradicting the experience gained in the energy crisis of 2022-23. We can expect that European demand would certainly react to high prices with demand response. Still, we must note that a 15% increase in gas demand combined with a full Russian gas phaseout would have and increasing price impact all over Europe.

Flow patterns and utilisation of infrastructure also show that when the pipeline is commissioned, all flows from the BG-MK interconnector are redirected to the new route. If additional CCGTs are added to the Macedonian demand, the pipeline is used nearly at capacity, but the BG-MK route is also needed to meet the increased demand. Results also show that the additional capacity of the gas system allows for flexibility of supply routes, and this will add to the resilience of the system and provides also flexibility in market terms. Competing

sources result in better prices on wholesale level in North Macedonia.

Promoters of the project and donors highlight the hydrogen readiness of the infrastructure. It is indeed a prudent way to plan for possible future hydrogen utilisation, as it is less costly to invest in a hydrogen ready pipeline than repurpose an existing one. Nevertheless, actual markets of hydrogen, particularly renewable hydrogen, are less developed yet and it is unclear what will be the market clearing price and whether this will allow for the operation of hydrogen fuelled CCGTs.

RESULTS OF THE ELECTRICITY MARKET MODELLING:

The analysis indicates that North Macedonia can operate safely without completing the new combined-cycle gas turbines (CCGTs), relying instead on imports for approximately 30% of its electricity consumption in 2030, which decreases to 25% in 2040. Thus, the completion of the projects is not a necessity for the country although it might be associated with benefits.

The potential new North Macedonian CCGTs contribute to lower domestic electricity prices, although the impact diminishes over time—from around €10/MWh in 2030 to nearly zero by 2040. Utilisation of the new CCGTs is expected to exceed 70% in 2030 but gradually declines thereafter too. In scenarios where reference gas prices are assumed and no additional CCGT investments occur in the region, utilisation remains above 40% throughout the study period, but with low gas prices and regional CCGTs it can reach as low as 5% in 2040. With these utilisation values Bitola power plant is not profitable in any of the analysed scenarios, while Negotino might be, however economic viability is heavily dependent on the scenario setup.

From an environmental perspective, the new CCGTs lead to higher CO₂ emissions in North Macedonia; however, in scenarios where only a few of the planned CCGTs are built in neighbouring countries, they contribute to a net reduction in regional emissions by displacing coal generation.

Expanding CCGT deployment in the surrounding region slightly reduces North Macedonian prices due to increased competition, while simultaneously lowering the utilisation of the domestic CCGTs and slightly increasing regional emissions. Moreover, a delayed entry of the WB6 region into the EU ETS leads to lower electricity prices and higher utilisation of the North Macedonian CCGTs, but this comes at the cost of significantly higher emissions both domestically and regionally. Thus, delayed entry is beneficial for the projects from an economic point of view, however associated with significant excess harm, considering the climate perspective. ETS participation is also closely linked with EU accession, and later accession would have economic impacts that were outside the scope of the model.

The modelling results suggest that it may be feasible to implement a project in North Macedonia that is simultaneously profitable and beneficial for regional GHG reduction, provided it is appropriately sized—likely a single CCGT rather than multiple units. Key conditions for such a project include maintaining investment costs within a reasonable range, keeping European gas prices around €40/MWh, avoiding substantial expansion of CCGTs elsewhere in the region, and not delaying entry to the ETS post 2030. If any of the described conditions are not met, the project turns out either to be unprofitable or will be associated with significant excess emissions.

Overall, the findings highlight the delicate balance between, economic efficiency, and environmental sustainability, and emphasise the importance of coordinated regional planning when considering new gas power investments.





ANNEX

7.1. GAS MARKET MODELLING

EGMM (European Gas Market Model) is a competitive, dynamic, multi-market partial equilibrium model that simulates the operation of the wholesale natural gas market across the whole of Europe. The detailed mathematical description of the model was published and is openly accessible in Energy Policy 2023 Volume 173⁴⁴. It includes a supply-demand representation of EU27 countries, United Kingdom, Switzerland, the Contracting Parties of the Energy Community⁴⁵ and Turkey, including gas storage and transportation linkages. Large external markets, including Russia, Norway, Libya, Algeria, Azerbaijan, Iran and LNG (Liquefied Natural Gas) exporters are represented exogenously with market prices, long-term supply contracts and physical connections to Europe.

The timeframe of the model covers 12 consecutive months and market participants have perfect information over this period. Dynamic connections between months are introduced by the operation of gas storages and take-or-pay constraints (minimum and maximum deliveries are calculated over the entire 12-month period, enabling contractual flexibility).

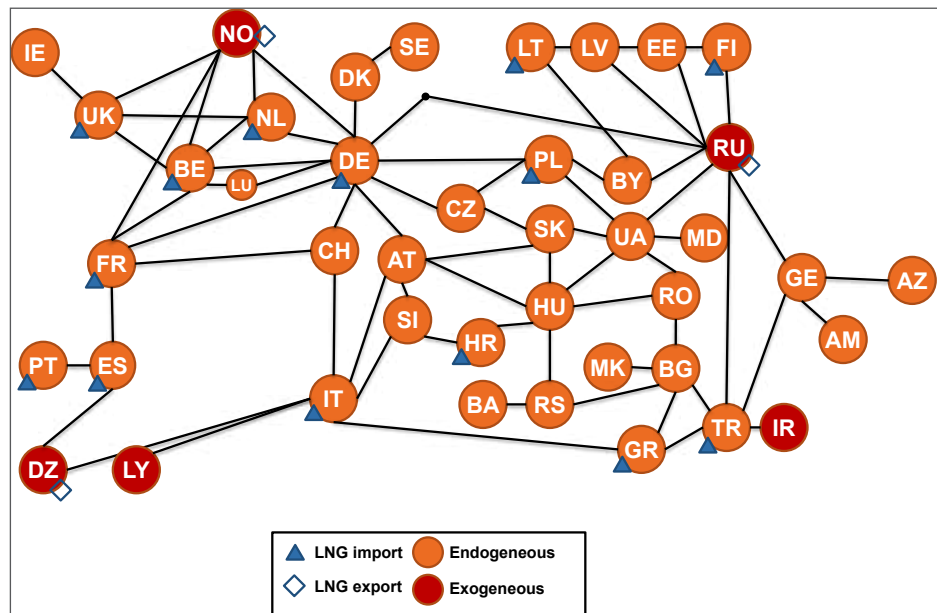
⁴⁴ Péter Kotek, Adrienn Selei, Borbála Takácsné Tóth, Balázs Felsmann (2023): What can the EU do to address the high natural gas prices? Energy Policy, Volume 173, 2023, 113312, ISSN 0301-4215, <https://doi.org/10.1016/j.enpol.2022.113312>. The model description is available in Annex 3.

⁴⁵ Contracting Parties of the Energy Community Treaty are: the European Union and Albania, Bosnia and Herzegovina, Georgia, Kosovo*, Montenegro, North Macedonia, Moldova, Serbia, Ukraine

The European Gas Market Model consists of the following building blocks: (1) local demand; (2) local supply; (3) gas storages; (4) external markets and supply sources; (5) cross-border pipeline connections; (6) LNG (liquefied natural gas) infrastructure (7) long-term take-or-pay (TOP) contracts; and (8) spot trading.

- ▶ **Local demand** is represented by demand functions. Demand functions are downward sloping, meaning that higher prices decrease the amount of gas that consumers want to use in a given period. For simplicity, we use a linear functional form, the consequence of which is that every time the market price increases by 0.1 EUR/MWh, local monthly consumption is reduced by equal quantities (as opposed to equal percentages, for example). The linearity and price responsiveness of local demand ensures that market clearing prices will always exist in the model. Regardless of how little supply there is in a local market, there will be a high enough price so that the quantity demanded will fall back to the level of quantity supplied, achieving market equilibrium.
- ▶ **Local supply** shows the relationship between the local market price and the amount of gas that local producers are willing to pump into the system at that price. In the model, each supply unit (company, field, or even well) has either a constant, or a linearly increasing marginal cost of production (measured in EUR/

Figure 21.
Geographical
representation of the
EGMM model
Source: REKK. Country
codes as ISO 3166-1 alpha-2
standards



MWh). Supply units operate between minimum and maximum production constraints in each month, and an overall yearly maximum capacity.

- ▶ **Gas storages** are capable of storing natural gas from one period to another, arbitraging away large market price differences across periods. Their effect on the system’s supply-demand balance can be positive or negative, depending on whether gas is withdrawn from, or injected into, the storage. Each local market can contain any number of storage units (companies or fields). Storage units have a constant marginal cost of injection and (separately) of withdrawal. In each month, there are upper limits on total injections and total withdrawals. There is no specific working gas fee, but the model contains a real interest rate for discounting the periods, which automatically ensures that foregone interest costs on working gas inventories are considered. There are three additional constraints on storage operation: (1) working gas capacity; (2) starting inventory level; and (3) year-end inventory level. Injections and withdrawals must be such during the year that working gas capacity is never exceeded, intra-year inventory levels never drop below zero, and year-end inventory levels are met.
- ▶ **External markets and supply sources** are set exogenously (i.e. as input data) for each month,

and they are assumed not to be influenced by any supply-demand development in the local markets. In case of LNG the price is derived from the Japanese spot gas price, taking into account the cost of transportation to any possible LNG import terminal. As a consequence, the price levels set for outside markets are important determinants of their trading volumes with Europe.

- ▶ **Cross-border pipelines** allow the transportation of natural gas from one market to the other. Connections between geographically non-neighbouring countries are also possible, which allows the possibility of dedicated transit. Cross-border linkages are directional, but physical reverse flow can easily be allowed for by adding a parallel connection that “points” into the other direction. Each linkage has a minimum and a maximum monthly transmission capacity, as well as a proportional transmission fee. Virtual reverse flow (“backhaul”) on unidirectional pipelines or LNG routes can also be allowed, or forbidden, separately for each connection and each month. The rationale for virtual reverse flow is the possibility to trade “against” the delivery of long-term take-or-pay contracts, by exploiting the fact that reducing a pre-arranged gas flow in the physical direction is the same commercial transaction as selling gas in the reverse direction. Additional

upper constraints can be placed on the sum of physical flows (or spot trading activity) of selected connections. This option is used, for example, to limit imports through LNG terminals, without specifying the source of the LNG shipment.

- ▶ **LNG infrastructure** in the model consist of LNG liquefaction plants of exporting countries, LNG regasification plants of importing countries and the transport routes connecting them. LNG terminals capacity is aggregated for each country, which differs from the pipeline setup, where capacity constraints are set for all individual pipeline. LNG capacity constraints are set as a limit for the set of “virtual pipelines” pointing from all exporting countries to a given importing country, and as a limit on the set of pipelines pointing from all importing countries to a given exporting country.
- ▶ **Long-term take-or-pay (TOP) contracts** are agreements between an outside supply source and a local market concerning the delivery of natural gas into the latter. Each contract has monthly and yearly minimum and maximum quantities, a delivery price, and a monthly proportional TOP-violation penalty. Maximum quantities (monthly or yearly) cannot be breached, and neither can the yearly minimum quantity. Deliveries can be reduced below the monthly minimum, in which case the monthly proportional TOP-violation penalty must be paid for the gas that was not delivered. Any number of TOP-contracts can be in force between any two source and destination markets. Monthly TOP-limits, prices, and penalties can be changed from one month to the next. Contract prices can be given exogenously, indexed to internal market prices, or set to a combination of the two options. The delivery routes (the set of pipelines from source to destination) must be specified as input data for each contract. It is possible to divide the delivered quantities among several parallel routes in pre-determined proportions, and routes can also be changed from one month to the next.

- ▶ **Spot trading** serves to arbitrage price differences across markets that are connected with a pipeline or an LNG route. Typically, if the price on the source-side of the connection exceeds the price on the destination-side by more than the proportional transmission fee, then spot trading will occur towards the high-priced market. Spot trading continues until either (1) the price difference drops to the level of the transmission fee, or (2) the physical capacity of the connection is reached. Physical flows on pipelines and LNG routes equal the sum of long-term deliveries and spot trading. When virtual reverse flow is allowed, spot trading can become “negative” (backhaul), meaning that transactions go against the predominant contractual flow. Of course, backhaul can never exceed the contractual flow of the connection.

7.1.1. EQUILIBRIUM

The European Gas Market Model algorithm reads the input data and searches for the simultaneous supply-demand equilibrium (including storage stock changes and net imports) of all local markets in all months, respecting all the constraints detailed above.

In short, the equilibrium state (the “result”) of the model can be described by a simple no-arbitrage condition across space and time. However, it is instructive to spell out this condition in terms of the behaviour of market participants: consumers, producers and traders. Infrastructure operators (TSO, storage and LNG operator) observe gas flows and their welfare is not factored in the equilibrium.

7.1.2. WELFARE

Welfare calculations are done ex post. The maximized value of the objective function is adjusted to properly account for actual welfare in the market. The operating profit of transmission and storage system operators is added using estimates for their marginal costs, and the expenditure on import contracts is increased by the take-or-pay fixed cost element.

Welfare components are assigned to regional and outside markets based on location. For consumer and local producer surplus, long-term contract profit,¹⁹ storage operating income and congestion rent, the assignment is straightforward. Pipeline operating income is shared in the ratio of entry and exit fees and pipeline congestion rent is shared equally by the neighbouring markets. LNG-related welfare components are assigned to the market hosting the terminal.” REKK EGMM model description based on Kiss, Selei and Tóth (2016)

7.1.3. OUTPUTS

Outputs of modelling are the wholesale gas market prices per country and the natural gas flows. Based on those outputs the model also calculated welfare on country and stakeholder level (consumer, producer, traders, infrastructure operators).

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In short, the equilibrium state (the “result”) of the model can be described by a simple no-arbitrage condition across space and time. However, it is instructive to spell out this condition in terms of the behaviour of market participants: consumers, pro-

ducers and traders. Infrastructure operators (transmission system operator (TSO), storage and LNG operator) observe gas flows and their welfare is not factored in the equilibrium.

7.2. ELECTRICITY MARKET MODELLING

The EPMM is a 168-hour unit commitment and economic dispatch model covering the electricity systems of 41 European countries. It simultaneously determines the equilibrium values of the wholesale electricity and reserve markets for each hour and market, taking into account the projected weather-dependent renewable generation, the electricity demand, the reserve requirements for each countries, and the technological constraints and costs (minimum operating and offtime, minimum / maximum load level, start-up / shut-down costs, variable costs of generation) for electricity generation and transmission. Using these inputs, the model predicts the operating status of the power plants every hour of the week (covering almost 3,500 power plants), the volume of generation at the operating units, the amount of capacities set aside for upward-regulation and downward-regulation, the operation of reservoir hydropower plants, the flows on all cross-border interconnectors, and the wholesale market price of electricity and the price of the upward and downward reserve capacities in each country.

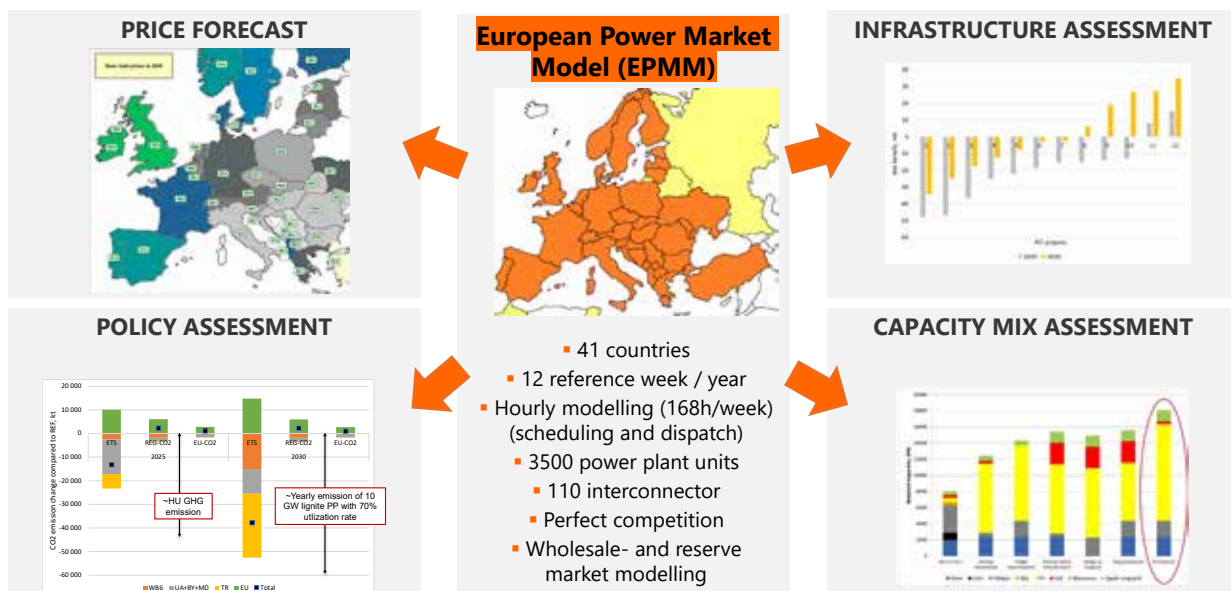
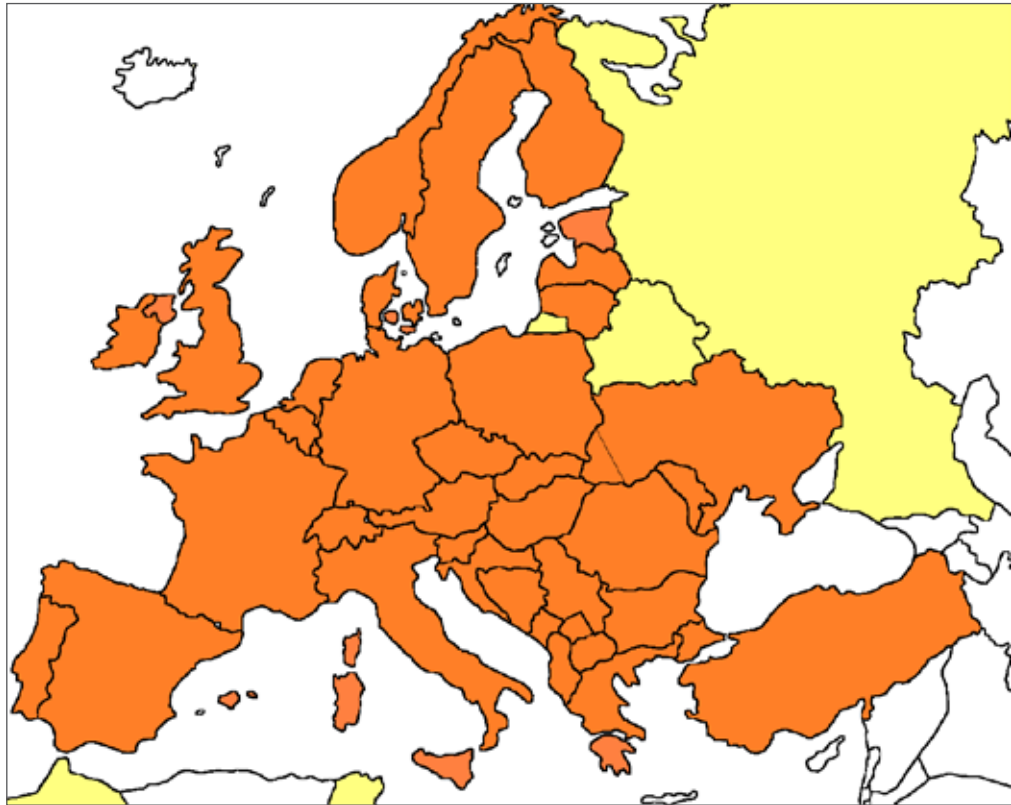


Figure 22.
Countries modelled in
EPMM



There are 41 countries modelled in EPMM: in these countries (indicated with an orange background on the following figure) prices are derived from the demand-supply balance, while on outside markets (indicated with yellow background) we assume exogenous prices.

There are three types of market participants in the model: producers, consumers, and traders. All of them behave in a price-taking manner: they take the prevailing market price as given and assume that their actions have a negligible effect on this price.

The EPMM models 3500 power plant units operated with 12 different fuels: natural gas, coal, lignite, heavy fuel oil (HFO), light fuel oil (LFO), nuclear, biomass, geothermal, hydro, wind, solar and tide and wave. Each plant has a specific marginal cost of production, which is constant at the unit level. In addition, generation capacity is constrained at the level of available capacity.

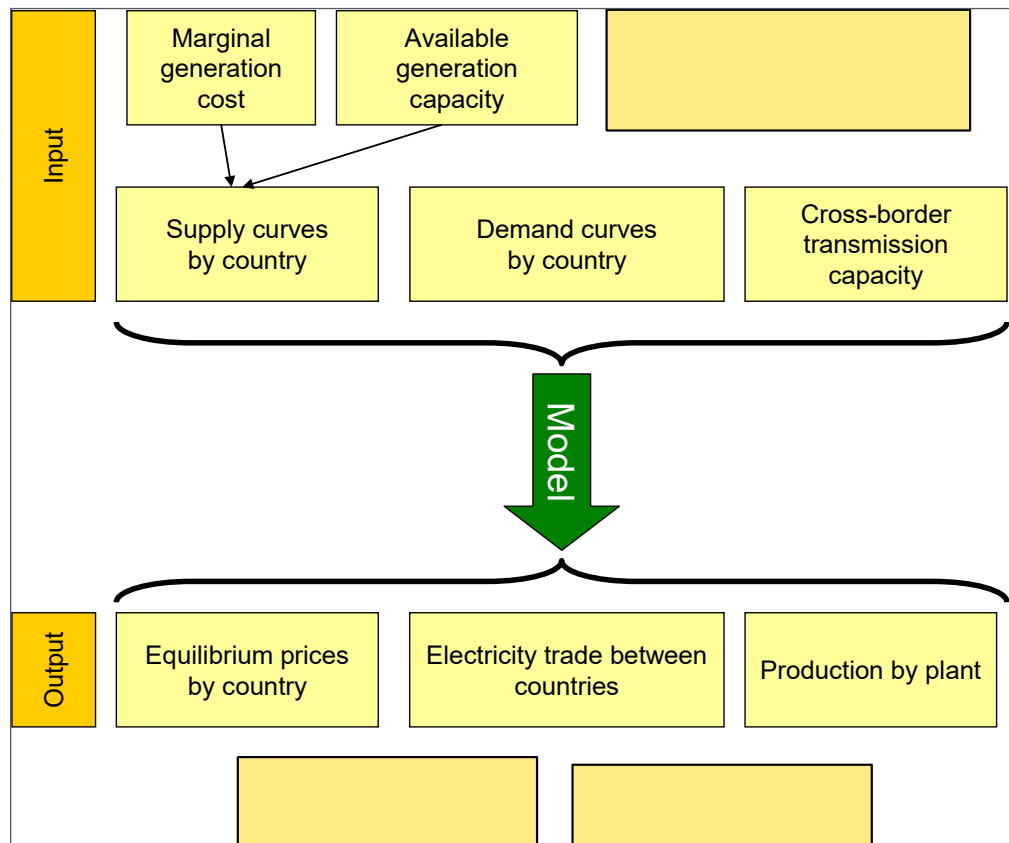
Power flow is ensured by 110 interconnectors between the countries, where each country is treated as a single node, thus no domestic power system constraint is taken into account. NTC values are

used to indicate trading possibilities, seasonal differences are included in the modelling based on historical data from ENTSO-E Transparency Platform. Future investments are assumed based on data from ENTSO-E's latest Ten-Year Network Development Plan (TYNDP).

Consumers are represented in the model in an aggregated way: by different price-sensitive demand curves for each modelled market. The inverse relationship between prices and the quantity consumed is approximated by a downward sloping linear function. Traders connect the production and consumption sides of a market, through exporting electricity to more expensive countries from cheaper ones.

Taking into account the short-term marginal cost for all available power plant units merit order curves are calculated for each market. With the demand curve and the constraints on international trade all input parameters are set. After that the model maximize the total welfare of the whole assessed countries. The model provides the equilibrium (wholesale) electricity prices for each market, the trade on each interconnector and the production of each power plant unit as output.

Figure 23.
Functioning of the model



7.2.1. SUPPLY SIDE OF THE MODEL

On the following figure methodology for marginal cost calculation of power plant units is presented. As perfect competition is assumed when the supply curve is formed all units provide their production on a marginal cost basis. To calculate marginal costs CO₂ emission cost, energy tax (if any), fuel cost and variable OPEX are summed up.

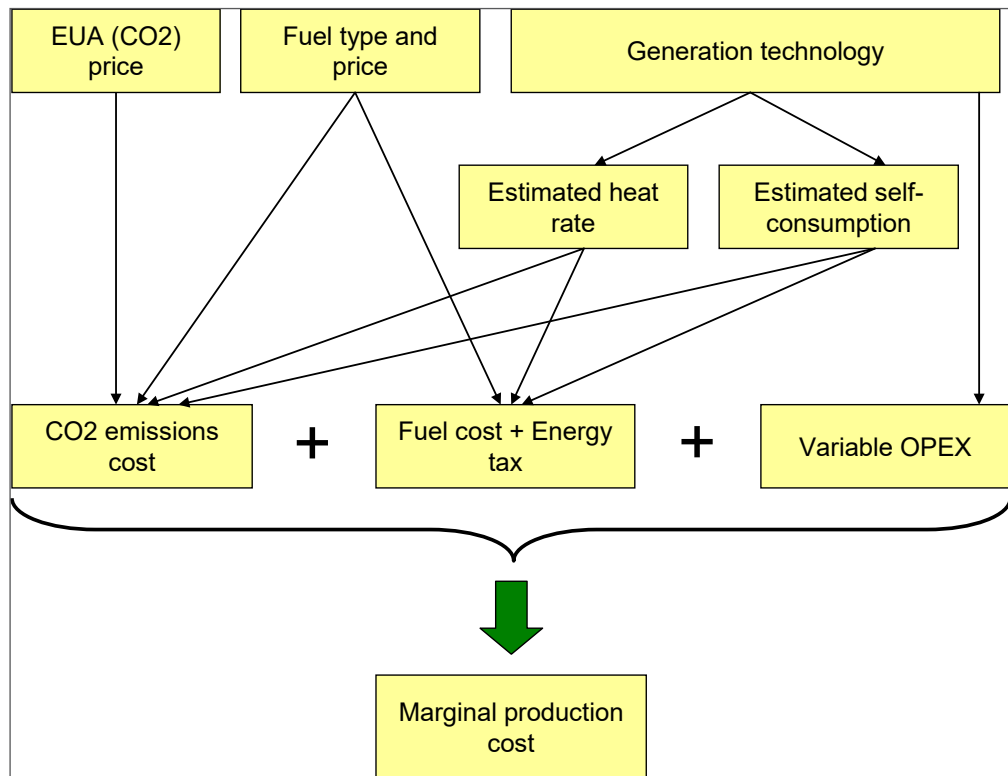
For all given technologies (e.g. OCGT, CCGT, thermal) commissioning date defines the efficiency, the self-consumption and the variable OPEX cost for all units. Using the fuel prices as an input total fuel costs are calculated taking into account the above parameters. CO₂ costs are based on the calculated emission level and the CO₂ quota prices, and all these costs are then added to the total energy tax paid and the variable OPEX.

It is important to note that only short-term marginal costs are considered, the model does not analyse whether long-term operation is profitable or not. It is possible, that some units remain operational even

if they provide electricity in a few hours per year. Power plant units are available until the end of their (pre-defined) lifetimes.

In the case of renewable power plants (biomass, geothermal, hydro, wind, solar, tidal), we calculate zero marginal cost on the product market, production depends only on availability. Renewable production (at a predetermined cost) can be curtailed. In the case of participation in the reserve market, we assume linear growth for wind and solar, with wind plants participating in the downward regulation up to 25% of their production and solar plants up to 15% of their production by the mid-2030s. The situation for hydropower is specific. With the exception of run-of-river plants, all hydropower plants (reservoir and pumped storage) optimise their production and reserve market participation for a full week, taking into account as a limit the maximum available production expected based on historical production data from previous years. These are used to determine the reserve market prices, while the marginal cost of the product market is zero on the supply curve.

Figure 24.
Methodology
for marginal cost
calculation



A regression model is used to forecast the future level of required reserve capacities: based on 5 years and 16 countries of data, upward and downward reserve requirements are forecast for each modelled country and each modelled hour, as a function of system load and weather-dependent renewable generation capacity.

7.2.2. DEMAND SIDE OF THE MODEL

Demand per country is an exogenous input to the model. Historical data are used to assume a specific demand pattern for each modelled country over the year, and assumptions are made about the actual level of demand based on forecasts from international institutions, literature and strategy documents. Between years, the initial demand path is unchanged, but it is endogenously shaped by (pumped) storage and demand side management (DSM) in each modelled year. For DSM, based on literature, it is assumed that by 2050, 25% of the average hourly consumption in a given year can be reallocated to other hours, and 10-10% of this amount can provide for upward and downward reserve capacity services. Between 2020 and 2050 we assume linear growth.

7.2.3. EQUILIBRIUM

Based on the capacity and marginal cost values of the generating units, and considering which units are in reserve, the supply function is determined for each modelled hour in each country. Demand can be met from neighbouring countries in addition to domestic supply, up to the limit of cross-border capacity. In the model, each market (country) is represented by a node, and the cross-border capacities are represented by estimated NTC (net transfer capacity).

