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Gas Decarbonisation Pathways for Estonia

(Baltic Regional Gas Market countries)

Deliverable 3: Report on relevant scenarios for a decarbonised Baltic Regional Gas Market by 2050

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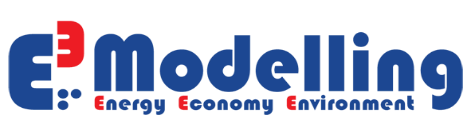
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# List of abbreviations

|  |  |
| --- | --- |
| 3B+F | Baltic States + Finland |
| BAU | Business-as-usual |
| CGH2 | Compressed hydrogen gas |
| CH4 | Methane |
| CM | Cost minimal |
| CNG | Compressed natural gas |
| CO2 | Carbon dioxide |
| CO2eq. | Carbon dioxide equivalent |
| DAC | Direct air capture |
| EE | Estonia |
| FI | Finland |
| GHG | Greenhouse gases |
| H2 | Hydrogen |
| LCOE | Levelised cost of energy |
| LEAP | Low Emissions Analysis Platform |
| LH2 | Liquified hydrogen |
| LNG | Liquified natural gas |
| LT | Lithuania |
| LV | Latvia |
| NEMO | Next Energy Modelling system for Optimisation |
| NG | Natural gas |
| PL | Poland |
| REN-Hydrogen | Renewable hydrogen |
| REN-Methane | Renewable methane |
| RGMCG | Regional Gas Market Coordination Group |
| SMR | Steam methane reforming |
| SNG | Synthetic natural gas |
| ToR | Terms of reference |
| UGS | Underground gas storage |
| USD | US dollar |

# Terminologies used in the report

***On-Network/Pipeline gas flows***

Gas flows in the natural gas (NG) pipeline network (transmission and distribution pipelines).

***Off-Network gas***

The term is referred to locally produced gas from the domestic/regional resources which can be consumed directly at the point of production or can be transported via trucks or other supply means but not injected in distribution or transmission NG networks (e.g., biogas in power plants, biomethane/hydrogen in transport, biomethane in industries, etc.)

***Regional LNG import infrastructure***

The existing and planned LNG terminals in the RGMCG countries (Estonia, Latvia, Lithuania, and Finland).

***Gas supply***

Domestic renewable gas production including LNG import in any of the countries in the region. The overall available gas can either be consumed within the country or can be supplied via transmission network to the any of the country in the 3B+F region.

***Gas production capacities***

Domestic renewable gas production capacities in the region. These capacities are further segregated into the gas production capacities for gas network injection and the production capacities for Off-Network (pure gas) utilisation.

***Pipeline gas storage***

The term throughout the report referred to gas storage facility/facilities connected to the regional NG network e.g., the Inčukalns underground gas storage facility which can be accessed (to inject and to withdraw) by all four (3B+F) countries in the region. The term specifically refers to the gas storage facility which will be able to store the pipeline gas blend. The term ‘pipeline gas storge’ does not refer to ‘line-pack storage’ and should not be confused with it.

***Off-Network gas storage***

Gas storage facility/facilities for Off-Network gases (not injected into distribution or transmission networks), e.g., storage options for pure hydrogen or biomethane.

***Levelised costs of renewable gases***

The term refers to the cost of production of the domestic renewable gases. It indicates the average cost of generating one Megawatt hour (MWh) of domestic renewable gases over the lifetime of a generating asset. It considers the costs associated with a system, including upfront investments (capital investment), operation & maintenance costs, and fuel costs.

***Exogenous/Endogenous capacities***

The exogenous capacities are referred to as the existing or planned infrastructure capacities, whereas endogenous capacities are those that model optimises to deploy additional/complementary to the existing or planned capacities.

**Note:** The above-mentioned terms are further described in the modelling methodology and scope in section Modelling Tools & Methodology.

# Introduction

This report presents the methodology and results of modelling conducted for Deliverable 3 of the *Gas decarbonisation pathways for Estonia* project. **The objectives of Deliverable 3 are to define and analyse the potential routes to decarbonise the Estonian gas sector by 2050, being a part of the common regional gas market (three Baltic States + Finland [3B+F])**. The modelling accounted for the relevant market, policy, and physical dynamics in Estonia, Latvia, Lithuania, and Finland and considered four future scenarios, namely the:

* Business-as-usual (BAU) scenario;
* Renewable methane focus (REN-Methane) scenario;
* Renewable hydrogen (REN-Hydrogen) scenario; and
* Cost Minimal scenario (exploring competition between renewable gases and NG to find the least cost decarbonisation solution for the modelled period, given set constraints and modelling boundaries[[1]](#footnote-2)).

The report is organised as follows:

* Chapter 2 of the report begins with an overview of the modelling scope, structure, and methodology before providing details on the simulation approach and characteristics of the modelled scenarios.
* Chapter 3 presents a detailed analysis of the BAU scenario (scenario without a climate neutrality requirement).
* Chapters 4, 5, and 6 illustrate the in-depth result analysis of scenarios with a requirement to achieve carbon neutrality of the regional gas market (REN-Methane, REN-Hydrogen, and Cost Minimal scenarios).
* Chapter 7 highlights the key messages of the modelling exercise while highlighting the key attributes of a cross-scenario result comparison.
* Chapter 8 presents the answers to the additional study questions addressed outside of the model boundaries. It highlights the impacts of hydrogen blending on NG infrastructure and end-use equipment by comparing different methods of hydrogen transportation and the related costs. Potential carbon dioxide (CO2) sources for synthetic natural gas (SNG) are discussed, and a cost comparison of different CO2 sources is presented. Finally, each country's renewable gas export potential in the joint regional gas market (3B+F) is discussed.

The overall philosophy of the Deliverable 3 modelling was to emphasise inputs and information sourced from Estonia, Latvia, Lithuania, and Finland transparently for the systematic treatment of future uncertainties. The analyses presented in this report are intended to inform policy and planning choices through credible simulations to decarbonise the regional gas market. The modelling seeks to illuminate trade-offs among the decarbonisation pathways and the viability of different renewable carriers for gas production. Results from the Deliverable 3 modelling will feed into the socioeconomic analysis, risk analysis, sensitivity analysis, and policy action plan development planned for the upcoming stages of the *Gas decarbonisation of Estonia* project.

# Modelling Tools & Methodology

SEI constructed a model using the [Low Emissions Analysis Platform (LEAP)](https://leap.sei.org) and the [Next Energy Modelling for Optimisation (NEMO)](https://github.com/sei-international/NemoMod.jl) to represent the regional gas system and simulate scenarios. Together, these software tools comprise SEI's energy modelling toolkit. LEAP has been used by over 50,000 practitioners in government, academic, and research organisations in more than 190 countries, with over 60 countries having used LEAP to develop their Nationally Determined Contributions to the Paris Agreement. NEMO is an optimisation platform designed with native LEAP interoperability in mind, and the two pieces of software operate together to provide advanced optimisation features alongside a graphical user interface for data input and result-viewing.

## Modelling scope and structure

This section details the model's coverage, divided into three sections: spatial, sectoral, and temporal range.

### Geography

The model represents energy demand and supply in four countries, making up the Baltic Regional Gas Market Coordination Group (RGMCG): Estonia, Latvia, Lithuania, and Finland. The model covers only energy demand from within these four countries; net exports to other neighbouring countries, historically or in any future scenario, are not considered. Situation is analysed as it was until end of 2022, that means the existing regional gas infrastructure assets[[2]](#footnote-3) and planned or announced assets[[3]](#footnote-4) are taken into account in this report and modelling assumptions. Energy supply from other neighbouring countries is included, represented as if it were an energy supply resource in the country to which those exports first arrive (see Table ‎2‑2 for how energy supply resources from other countries are represented in the model’s scope).

### Fuels, Sectors and Technologies

This analysis explores pathways for the region to transition away from natural gas and towards a decarbonised gas system comprised of biomethane or biogas, hydrogen, and potentially synthetic natural gas (SNG). As a result, the model represents consumption and production, transport, and energy storage only for gaseous fuels. Changes in gaseous fuel use that arise from increased electrification or displacement by other fuels are considered outside the LEAP and NEMO model framework and added as a pre-calculated input regarding gas demand levels.

Within the four RCGMG countries, the model represents gas consumption for each fuel, detailed in Table ‎2‑1 below.

Table ‎2‑1. Gas consumption detail by fuel for the region

| Country | Level of Detail | Fuels Covered |
| --- | --- | --- |
| RGMCG countries[[4]](#footnote-5) | Total national consumption | Pipeline Gas[[5]](#footnote-6), Biogas, Biomethane, Green Hydrogen |

On the energy supply side, individual modules are comprised of groups of gas production technologies that output the same gaseous fuel.

Table 2‑2 describes these energy supply modules by listing the fuel each produces, the resources that can produce that fuel as an output, and the feedstock that each resource transforms into its output fuel.

Table ‎2‑2. The energy production sector includes output fuel, resource, and input fuel

|  |  |  |
| --- | --- | --- |
| Output Fuel | Supply Resources or Production Technology | Input (Feedstock) Fuel |
| Pipeline Gas (comprised of natural gas, biomethane, green hydrogen, and synthetic natural gas) | Natural Gas from LNG Terminal | LNG |
| Natural Gas via pipelines from Russia or Belarus (No imports after April 2022) | Natural Gas |
| Natural Gas via pipeline from Poland | Natural Gas |
| Electrolysis | Electricity |
| Synthetic Natural Gas (Methanation reactor) | Electricity (electricity is assumed to produce hydrogen to react with carbon dioxide) |
| Agricultural Waste Digestion | Agricultural Waste |
| Wastewater Digestion | Wastewater |
| Landfill Waste Digestion | Landfill Waste |
| Biowaste | Biomass |
| Pipeline gas Storage (UGS) | Pipeline & underground gas (not consumed as feedstock but stored for later use) |
| Biomethane (off-Network) | Agricultural Waste Digestion | Agricultural Waste |
| Wastewater Digestion | Wastewater |
| Landfill Waste Digestion | Landfill Waste |
| Biowaste Digestion | Biowaste |
| Biomethane Storage | Biomethane (not consumed as feedstock but stored for later use) |
| Green Hydrogen (off-Network) | Electrolysis | Electricity |
| Hydrogen Storage | Renewable Hydrogen (not consumed as feedstock but stored for later use) |
| Biogas | Agricultural Waste Digestion | Agricultural Waste |
| Wastewater Digestion | Wastewater |
| Landfill Waste Digestion | Landfill Waste |
| Biowaste | Biomass |

Hereinafter, "production" means a process that satisfies the energy requirement for a particular fuel. Production processes may represent the creation of fuel from feedstock, or they may represent the arrival of fuel from outside the RGMCG region

In addition to the energy supply resources described above, blended pipeline gas (a mixture of natural gas, biomethane, hydrogen and SNG) produced in one country may be transported to another using the three existing bi-directional transmission pipelines (see in sub-section 2.4.2 *On-Network Pipeline Gas*). Other fuels that do not get injected in the pipelines are called "off-network" fuels[[6]](#footnote-7), since they are assumed to be consumed in the same country within which they are produced. Off-network includes pure unblended biomethane, pure unblended renewable hydrogen, and biogas.

### Time Horizon and Resolution

The time horizon represented by the model is composed of two separate epochs: the historical period, which is used to describe the current or historical status of the energy system, and the scenario period, during which different scenario assumptions are explored. The historical period begins in 2015 and extends to 2021, after which the scenario period covers 2022 through 2050. Wherever possible historical data are included for each year of the historical period, generally, data can be specified, and results viewed annually. Selected data inputs and results are available every month.

## Modelling methods

### *Software Tools*

The figure below presents a schematic of the integrated modelling and shows the respective roles of LEAP and NEMO.

Figure ‎2‑1. Schematic of LEAP-NEMO model

Diagram

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Within the modelling toolkit, LEAP and NEMO fulfil separate functions. The critical modelling tasks fulfilled using LEAP are:

* Model structuring (adding regions to represent each RGMCG country, creating supply and demand sectors, associating fuels or other resources with each industry),
* Scenario creation and management,
* Data input, including historical data and future assumptions in each scenario,
  + Some input assumptions are provided in a text-only format directly to NEMO, where LEAP does not natively support those inputs.
* Energy demand accounting,
* Energy supply simulation for renewable gas production and natural gas import,
* Cost accounting for all sectors modelled using LEAP,
* Emissions accounting for all sectors modelled using LEAP.

Generally, NEMO interacts with LEAP to provide the least-cost optimisation capabilities within a single energy supply module. However, in this model, NEMO is engineered to offer optimisation capabilities for three energy production sectors listed in Table ‎2‑2 (biomethane production, renewable hydrogen production, and pipeline gas production). Within these sectors, NEMO fulfils the following roles:

* Energy production, underground gas storage injection and withdrawal
* Capacity additions,
* Transmission pipeline utilisation,
* Cost accounting for sectors modelled using NEMO,
* Emissions accounting for sectors modelled using NEMO.

In addition to LEAP and NEMO, Microsoft Excel and SQLite are used where necessary to display and post-process modelled results. Figure 2‑2 presents a snapshot of the model's internal structure.

Figure 2‑2. Sample model structure with a focus on demand (left) and gas production and supply (right)

Graphical user interface, text, application

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## Gas Demand

Yearly gas demand forecasts[[7]](#footnote-8) for each country and fuel included in the model's scope are developed outside the LEAP/NEMO modelling platform (**for the detailed gas mix and gas demand assumptions, see the attached file in Annex A**) and input directly into LEAP as an annual time series of fuel requirements. Annual energy demands are then divided into twelve monthly energy demands, using a demand curve that allocates the percentage of each year's yearly demands occurring each month. In Latvia, Lithuania and Finland, no sectoral demand information is represented in the model, so all national gas consumption in these countries is assigned the same demand curve derived from each country's national monthly demand for natural gas. Estonia's monthly national and monthly gas demand for buildings are available separately. These derive a demand curve for buildings and a separate curve for all other sectors (by first subtracting building natural gas demand from national demand and calculating the monthly allocation of energy requirements from the difference). Although monthly demand curves are constructed using historical monthly demands for natural gas, the same curve is assigned to all gaseous fuels that may be consumed in each scenario. The sub-annual demand curves in Annexe A can be seen in the attached file.

## Gas Supply

LEAP is designed to sum energy demands for each fuel across all demand modules, which then become monthly requirements for energy supply processes in that same country. One or more energy supply processes operate together within a production module[[8]](#footnote-9), which attempts to meet the energy requirements for that sector’s output.

Table ‎2‑2 lists the set of supply resources or production technologies (collectively called *processes*) for each fuel produced within the model.

**For each energy production side (On-Network and Off-Network), LEAP and NEMO are used to answer two fundamental questions**:

1. How much gas is produced, and from which processes?
2. How much capacity is required, and for which processes?

Energy production requirements in each month are set by summing the energy demands for each fuel. **Capacity requirements in each year are set by the capacity needed for the highest demand month** (peak demand month)[[9]](#footnote-10). The model’s role is to attempt to satisfy both the energy production and capacity requirement and provide answers to the two questions above.

### Rules-Based Energy Supply Simulation using LEAP

Biogas and natural gas production are simulated entirely within LEAP without using NEMO. LEAP offers several methods for determining how future production, and production capacity, will evolve. Each method can be described as "rules-based", meaning that they rely on predetermined rules that dictate how energy and capacity needs are met.

#### Off-Network Biogas Production

For the production of pure biogas, existing production capacity from agricultural waste, wastewater, landfill waste, and biowaste is represented in each country. As energy requirements change yearly in each scenario, production capacity is added in predetermined ratios. The four biogas technologies meet the criteria for biogas each month, with each technology contributing to the sector's overall energy production in proportion to its pre-existing total capacity.

### Least-Cost Energy Supply Simulation using NEMO

In contrast to LEAP's rules-based method for capacity additions and energy production, NEMO performs a least-cost optimisation to simultaneously find capacity additions and monthly energy production for each process in each scenario year. The optimal solution is the mix of capacity and energy production that results in the lowest net present cost, considering all cost inputs provided: capital, fixed operation and maintenance (O&M), variable O&M, and input fuel costs (**see inset box**). The optimal solution may also include dedicated underground gas storage capacity, which operates by absorbing gas in some months and releasing it during others.

In addition to the primary goals of ensuring sufficient energy is produced, and adequate capacity added, several additional constraints may be applied within the model, which NEMO must obey as it searches for a least-cost solution. These constraints vary by scenario and by energy production sector.

#### Off-Network Biomethane Production

Costs in LEAP and NEMO

The model relies on a set of cost inputs to perform two functions. The first is to generate overall cost results, which can be compared across scenarios to assess total social costs. The second role of cost inputs in the model is to provide a basis for the least-cost optimisation used by NEMO.

This model assigns each energy supply resource or production technology capital costs and fixed and variable operation and maintenance costs. Costs for input fuels (consumed to produce biomethane, biogas, hydrogen, SNG and pipeline gas) are also included. Costs are specified for each relevant fuel, in each year, and for each country.

**Transmission Pipeline Costs**

Only fixed and variable operation and maintenance costs are represented for transmission pipelines. Capital costs are ignored because no additional international pipeline capacity is considered in any scenario, and the capital costs for existing pipelines are considered sunk.

New production capacity needs are governed by increasing demands for biomethane, with dedicated biomethane storage capacity added if it is cost optimal. Regardless of the overall level of biomethane required, an additional constraint is included that forces agricultural waste, wastewater, landfill waste, and biowaste to be used in predetermined shares. These shares remain constant yearly but are differentiated by country (**see Annex D**).

#### Off-Network Hydrogen Production

As with pure biomethane, new production capacity needs are governed by increasing demands for pure hydrogen, with dedicated hydrogen storage capacity added if it is cost-optimal to do so. Electrolysis is the only technology in the model capable of producing renewable hydrogen, so the technology must meet all pure hydrogen requirements.

#### On-Network Pipeline Gas

Pipeline gas comprises natural gas, biomethane, renewable hydrogen, and SNG. It may also be transported among countries via the region’s three existing gas pipelines (but currently there are no injection points on the regional transmission network). These are:

* Vireši - Tallinn pipeline, connecting Estonia to Latvia;
* The Balticconnector pipeline, connecting Estonia to Finland;
* Vilnius – Rīga pipeline, connecting Latvia to Lithuania.

This means that, unlike off-network fuels, on-network pipeline gas may be produced in one country but consumed in another to meet that country's demands. When this occurs, a country's pipeline gas production may exceed its domestic requirements. Only the three existing transmission pipelines can transport pipeline gas among countries. Their ability to carry energy is limited by their current energy capacity per unit of time; the model will not add other pipelines in any scenario. Additional underground gas storage capacity is not permitted in any of the scenarios. Because of the transmission pipelines, the existing underground gas storage capacity in Latvia can function as an emergency supply resource for the whole RGMCG region.

Depending on the country, natural gas can be supplied to the mix by LNG terminals, Inčukalns UGS or imports from Poland[[10]](#footnote-11). Biomethane is supplied by agricultural waste digestion, wastewater digestion, landfill gas digestion and biowaste. Hydrogen and SNG for blending are each produced from a single process. The model may add additional capacity to any process as long as the constraints in each scenario allow it. For example, in the Business-as-Usual and Hydrogen scenarios, no additions of SNG capacity may be added. The expansion of new import capacity from Poland is prohibited under any scenario.

Using NEMO, the model chooses from among all energy supply resources (including energy production, storage, or transmission to or from another country) to meet each country's requirements for pipeline gas in each month and scenario year. In addition, constraints are applied to each country's overall portfolio of resources used to produce pipeline gas. These are:

* Minimum energy production requirements for biomethane and renewable hydrogen differ in each year and each scenario. Minimum SNG production requirements are also imposed in the renewable methane-focused scenario. Biomethane can be produced from any of the four feedstocks described earlier, but the share of blended biomethane from each feedstock in each country is another constraint provided to the model (see Annex D).
* Predetermined percentages[[11]](#footnote-12) of biomethane, hydrogen, and SNG in overall pipeline gas energy production. These percentages differ in each year and each scenario. Where these percentage shares do not sum to 100%, natural gas from LNG terminals or Poland will make up the remainder.

The combined effect of these two constraints – the minimum energy production and fixed blending share – means that the model forces each country to produce (at minimum) a predetermined amount of each gas while maintaining a predetermined blending ratio. Both constraints continue to be met even when the demand for pipeline gas changes. For technologies that produce pipeline gas, capacity is added so that the energy production constraints may be met and also to ensure that is enough capacity for the highest-demand month.

### Key modelling assumptions

#### Biomethane feedstock availability and cost

Due to biomass feedstock dispersion across the country, biomethane is considered to be produced at regional level. Biomethane feedstock streams such as biowaste and sewage/wastewater have not been allocated any fuel cost. Biowaste streams are considered to be delivered to the local biomethane/biogas production plants by the waste producers. In this way, the responsible entity can avoid the gate fee for the waste disposal by covering only the transport cost of the biowaste delivery to the plant and the biomethane/biogas plant owners can avoid costs attached to the feedstock transportation and handling before it enters the plant premises. On the other hand, the agricultural residues are considered to have a market value of 64 Euro/ton (2022), and any further transportation costs of the feedstock are not considered.

#### CO2 source for SNG production

Since CO2 is co-produced in biogas upgradation process, it is considered that the biomethane production plants can supply the required CO2 for SNG production. Consequently, CO2 capture costs can be avoided. Due to the inherent lucrative nature of the combination, CO2 sources from local biogas upgradation plants are selected for SNG production in the modelling.

#### Gas storage

Model includes two distinct gas storage infrastructures, pipeline gas storage and Off-Network gas storage options. Under pipeline gas storage, surplus renewable gases (in the blended state) from any of the 4 countries (3B+F) countries are allowed to store their sub-annual renewable gas surplus (in the blended state) at the Inčukalns UGS in Latvia via selected injection points at the transmission gas network in the respective countries. Within the modelling scope, it is considered that the existing gas storage capacity at Inčukalns is enough for pipeline connected storage and model is constrained not to add any new pipeline connected capacity. On the other hand, Off-Network gases (pure biomethane and pure renewable hydrogen) are considered to be stored in surface storage facilities (pressurized gas storage for biomethane and Liquid organic hydrogen carrier (LOHC) technology for hydrogen). Model can deploy Off-Network gas storage capacities if it optimises to do so.

#### Biomethane plant utilisation rate

As per the communications with the biomethane experts, biomethane plant utilisation rate is taken as 85% (constant throughout the year).

#### LNG utilisation rates

LNG terminal’s utilisation rate is taken as the historical plant utilisation of the Klaipeda LNG terminal, as it is the only functional LNG terminal at the time of the modelling exercise. To have a realistic sub-annual utilisation curve for LNG terminals, Klaipeda LNG terminal’s utilisation rates before (2021) and after (2022) Russian invasion of Ukraine are averaged.

#### Electrolyser availability

For hydrogen produced from electrolysis, the load factor is assumed to be the same as the average monthly capacity factor of wind electricity (see Annex E).

#### Renewable electricity price

Hydrogen is considered to be produced only through electrolysers using renewable electricity (only onshore and offshore wind power because of the very low monthly capacity factor of solar). Levelised costs projections of renewable electricity are based on projection data from IRENA 2022 and Lazard 2021 (Annex D).

#### Candidates for endogenous capacity expansion

Model contains a projection of planned or announced (exogenously specified) gas infrastructure expansion (e.g., new LNG import facilities etc.). These projections also include assumptions about anticipated retirements of the existing or planned (exogenously specified) infrastructure capacities (e.g., Klaipeda LNG terminal’s retirement in 2044 and the lease expiration of Inkoo FSRU in 2033 etc.). In all scenarios, the model is permitted to complement the existing or planned LNG terminal capacity in the region. Model is permitted to add any new renewable gas production. These capacity requirements in each year are set by the capacity needed for the highest demand month (peak demand month), meaning that the required total installed capacity in a year is dictated by the peak load month. In all scenarios, the model is constrained not to add any new cross-border pipeline capacities, or any new pipeline connected storage capacity (as there are no other UGS points in the region and no further storage capacity expansion of Inčukalns is considered).

#### Levelised costs of production of the renewable gases

Levelised cost of producing renewable gas is calculated by dividing the overall discounted costs associated with a renewable gas generating system over a time slice (including discounted capital cost, discounted operational and maintenance costs, and discounted fuel costs) by the total energy of the gas produced by the renewable gas production asset in that time slice. It is shown in Euro/MWh.

#### Natural Gas/LNG import from outside the RGMCG region

The model refers the NG import as the import from the “third-country” from outside the RGMCG region (Russia, Belarus, or Poland (via GIPL), or rest-of-world via an LNG terminal) from which each RGMCG imports gas supply, using separate LEAP Transformation Processes for each.

Due to the Russian invasion of Ukraine, Europe stopped importing NG from Russia in the mid of 2022. Thus, the model is constrained not to import any Russian NG in the region after May 2022. The model optimises the future NG or LNG imports (compressed NG if from GIPL and LNG if from the regional LNG terminals), the future gas flow volumes between the RGMCG countries as per the existing interconnector capacity availability within the region, and the future utilisation of the regional gas storage in Latvia.

As discussed above, the model has two possibilities for the future NG import, either from the existing/planned/newly calculated LNG terminal capacities in the form of LNG and regasifing it or from the GIPL (Lithuania-Poland) pipeline interconnection. There is no import restriction on the LNG terminal module in the model, but the plant utilisation is dictated by the plant availability curve for which Klaipeda LNG terminal’s real sub-annual utilisation data for 2021 and 2022 is averaged. On the other hand, the GIPL (Lithuania-Poland) pipeline interconnection became operational and so far, has one sided gas flows (from Lithuania to Poland). For GIPL, the model contains the constraint of using the historical gas import data for the optimisation of the future gas import.

## Modelled scenarios

The project used the Deliverable 3 model to explore four future scenarios for the joint regional market in 3B+F. The scenario without a climate neutrality requirement is attributed as a Business-as-usual scenario based on the existing climate and energy policy framework, assuming no significant increase in climate change mitigation ambition. On the other hand, three different climate-neutral scenarios are considered: renewable methane focused that explores the impacts of investing in mainly biomethane and SNG in the region (3B+F), renewable hydrogen focused that explores the effects of investing in a renewable hydrogen-based gas infrastructure and cost minimal scenario that allows the competition between different fuels, given set constraints. Table ‎2‑3 provides an overview of the scenarios’ definitions, while sections 2.5.1, 2.5.2, 2.5.3, and 2.5.4 describe each scenario's main assumptions and critical characteristics in more depth.

Table ‎2‑3. Overview of the scenario definitions (qualitative comparison of the explored scenarios for the 3B+F joint gas market)

| **Indicators** | **Scenario 1** | **Scenario 2** | **Scenario 3** | **Scenario 4** |
| --- | --- | --- | --- | --- |
| **Scenario definition** | ‘Business-as-usual’ | ‘REN -Methane dominant scenario’ | ‘REN -Hydrogen dominant scenario’ | ‘Cost minimal scenario’ |
| **Decarbonisation level** | Non-Climate neutral scenario (Joint gas market is not decarbonised by 2050) | Climate-neutral scenarios (Gas sector is decarbonised by 2050) | | |
| **End-user decisions** | | | | |
| **End-user decisions regarding the applications in demand sectors** | Focus on methane-based end-user applications | Focus on methane-based end-user applications | Focus on hydrogen-based end-user applications | Focus on the least cost-based fuel mix (with the hydrogen technical limitation constraints without significant investment for retrofitting) |
| **Major gas carrier** | NG is still a major part of the gas demand (followed by biomethane and hydrogen and a small portion of biogas) | Methane (includes biomethane and SNG and followed by H2 and a small portion of biogas) | Hydrogen (followed by a small portion of biomethane and biogas) |
| **Strategy for the gas infrastructure to follow end-user decisions** | | | | |
| **Gas type expected within a national and cross-border gas infrastructure** | NG followed by biomethane and hydrogen | Short term: NG followed by biomethane, SNG, and hydrogen  Long-term: Biomethane followed by SNG and hydrogen | Short term: NG followed by hydrogen  Long term: NG followed by hydrogen and eventually pure hydrogen | Optimised scenario for the least cost solution (with the hydrogen technical limitation constraints without significant investment for retrofitting) |
| **Hydrogen blending** | Up to 5 vol.% | Up to 10 vol.% | Up to 10 vol.%  and eventually 100 vol.% pure hydrogen |
| **NG infrastructure** | No retrofitting of gas supply infrastructure is envisioned | No heavy retrofitting on gas supply infrastructure is envisioned  Technical possibilities of biomethane and hydrogen injection in transmission and/or distribution lines are considered. | No heavy retrofitting on gas supply infrastructure is envisioned for blending levels up to 10 vol.%  By 2041, total repurposing of the NG network infrastructure (TSO and DSO lines) is envisioned.[[12]](#footnote-13) | Retrofitting constraints (on the NG network infrastructure) are envisioned if the hydrogen blending levels cross the threshold of 10 vol.% |
| **End-user equipment adaptation** | No retrofitting constraints for end-use applications are considered except for the applications where the end equipment is sensitive to the NG gas quality**.** | Retrofitting constraints for end-use specific applications. | Retrofitting or replacement constraints for end-use-specific applications. | Retrofitting constraints for end-use specific applications. |
| **Gas supply infrastructure in use** | The role of transmission lines remains largely intact. Gas distribution via DSO lines. | The role of transmission lines remains largely intact. Gas distribution via DSO lines. | The role of transmission lines remains largely intact. Gas distribution via DSO lines. | The role of transmission lines remains largely intact. Gas distribution via DSO lines. |
| **Deployment of dedicated gas pipelines by TSO and/or DSO** | Limited and separated hydrogen networks may exist. New reliable pipelines are not modelled, but comparative cost feasibility of pure gas supply modes will be provided in a case study (dedicated pipeline vs. gaseous truck transport) | | | |
| **Change of demand between scenarios** | Baseline demand projections | Gas demand projections with electrification considerations | | |
| **Gas storage** | Conventional large-scale underground methane storage with an assumption to be able to store blended gas up to 10 vol.% H2[[13]](#footnote-14) | | Conventional large-scale underground methane storage with an assumption to be able to store blended gas up to 10 vol.% H2 blends and pure H2 after 2040. | Conventional large-scale underground methane storage with an assumption to be able to store blended gas up to 10 vol.% H2 blends |

### Business-as-usual (BAU) scenario

The BAU scenario assumes no new climate change mitigation requirements are implemented in the study area in addition to what already exists in the National energy and climate plans and other existing strategy documents. The BAU scenario is the first scenario modelled for Deliverable 3. It assesses implications for Estonia and other joint gas market participant countries (Latvia, Lithuania, and Finland) if the region's gas systems develop without a carbon neutrality requirement. Unless otherwise noted, the BAU and all other modelled scenarios use the methods described in section 2.2. Complementing these, the BAU also includes different vital assumptions, as outlined below.

| Defining characteristics of the BAU scenario |
| --- |
| * Final gas demand[[14]](#footnote-15)   + To be covered by NG, followed by biomethane and hydrogen. NG is still to be a significant part of the gas supply by 2050   + Estonia: Gas demand projection based on Civitta Eesti, 2021[[15]](#footnote-16) and verified by Elering   + Finland: Gas demand estimates provided by the Ministry of Energy Finland   + Latvia: Gas demand estimated based on RS2020[[16]](#footnote-17), verified by the Ministry of Economics of Latvia   + Lithuania: Estimated based on RS2020, verified with the Ministry of Energy Lithuania * Gas production and storage capacity   + Biomethane production as per existing country-specific targets specified in National energy and climate plans and other strategy documents   + Distributed (regional) biomethane production and injection in DSO & TSO system/grid   + Renewable hydrogen production as per country profiles from Fuel cell hydrogen joint undertaking (FCH JU 2020)[[17]](#footnote-18), low demand scenario   + Hydrogen injection at transmission gas network up to 5 vol.% by 2050   + No additions to synthetic natural gas (SNG) capacity   + No further reserves of underground gas storage (i.e., only existing Inčukalns UGS)   + Off-network gas storage capacity for biomethane and hydrogen may be added based on the model optimisation * Gas transmission   + The modelled area (3B+F): Includes existing (historical and the most recent till May 2022) pipelines and cross-border interconnectors.   + Third country: No Russian/Belarusian gas flows available after mid-2022. * LNG terminal capacities   + The modelled area includes existing and planned capacities.   + The model optimises the LNG terminal capacity based on the LNG terminal sub-annual utilisation curve given in Annex D – Technical assumptions.   + Additional required capacities may be added based on the model optimisation. * ETS price projection: Based on projection data[[18]](#footnote-19) (S&P Global, 2022)[[19]](#footnote-20) and (REUTERS, 2022)[[20]](#footnote-21) (Annex D) * Levelised costs of renewable electricity: Based on projection data from IRENA 2022[[21]](#footnote-22) and Lazard 2021[[22]](#footnote-23) (due to the low-capacity factor of solar, only onshore & offshore wind power is considered – See Annex D) * Climate-neutral gas supply in 3B+F: not fulfilled |

Figure ‎2‑3 illustrates the BAU scenario approach for the Baltic-Finnish region. For a detailed scenario storyline, see the attached file in Annex A.

Figure ‎2‑3 Holistic vision of BAU scenario

Diagram

Description automatically generated

### Renewable Methane focused (REN-Methane)

The renewable methane-focused (REN-Methane) scenario assumes a climate change mitigation ambition and carbon-neutral gas supply solution to be implemented by 2050 to enable the region towards carbon neutrality. The REN-Methane scenario is the second scenario modelled for Deliverable 3. It assesses the implications of the future carbon-neutral gas supply systems for Estonia and other joint gas market participant countries (Latvia, Lithuania, and Finland). Unless otherwise noted, all modelled scenarios use the methods described in section ‎2.2. Complementing these, the REN-Methane also includes other vital assumptions as outlined below.

| Defining characteristics of the REN-Methane scenario |
| --- |
| * Final gas demand[[23]](#footnote-24)   + To be covered by biomethane followed by hydrogen and SNG (SNG injection only in NG gas network to cover the remaining gas share in pipelines due to H2 blending limitations – no off-network use of SNG), SNG will be produced from the C02 captured in the biomethane plants (costs are explained in the later section).   + Baseline gas demands from the BAU scenario are updated for the reduced demand implications due to the electrification effect based on EU infra. Study[[24]](#footnote-25) * Gas production and storage capacity   + Biomethane production as per country-specific technical (economically realisable) production potential (discussed and verified with each member state, see sub-section 5.1 of Deliverable 2 ‘Baseline data collection’ report)   + Distributed (regional) biomethane production and injection in DSO & TSO lines   + Renewable hydrogen production as per country profiles from (FCH JU 2020)18, low demand scenario   + Hydrogen injection at transmission gas network up to 10 vol.% by 2050   + Addition of synthetic natural gas capacity according to the need to fulfil the pipeline gas requirement   + No further reserves of underground gas storage (i.e., only existing Inčukalns UGS   + Off-network gas storage capacity for biomethane and hydrogen may be added based on the model optimisation * Gas transmission   + The modelled area (3B+F): Includes existing (historical and the most recent till May 2022) pipelines and cross-border interconnectors.   + Third country: No Russian/Belarusian gas flows available after mid-2022. * LNG terminal capacities   + The modelled area includes existing and planned capacities.   + The model optimises the LNG terminal capacity based on the LNG terminal sub-annual utilisation curve given in Annex D – Technical assumptions.   + Additional required capacities may be added based on the model optimisation. * ETS price projection: Based on projection data[[25]](#footnote-26) from (S&P Global, 2022)20 and (REUTERS 2022)21 (Annex D) * Levelised costs of renewable electricity: Based on projection data from IRENA 202222 and Lazard 202123 (due to the low capacity factor of solar, only onshore & offshore wind power is considered – See Annex D) * Climate-neutral gas supply in 3B+F: fulfilled |

Figure ‎2‑4 illustrates the Ren-Methane scenario approach for the Baltic-Finnish region. For a detailed scenario storyline, see the attached file in Annex A.

Figure ‎2‑4 Holistic vision of the REN-Methane scenario

Diagram

Description automatically generated

### Renewable Hydrogen-focused (REN-Hydrogen)

Similar to the REN-Methane scenario, the renewable hydrogen-focused (REN-Hydrogen) scenario assumes a climate change mitigation ambition and carbon-neutral gas supply solution to be implemented by 2050 to enable the region towards carbon neutrality. It is the third scenario modelled for Deliverable 3. It assesses the implications of the future carbon-neutral gas supply systems for Estonia and other joint gas market participant countries (Latvia, Lithuania, and Finland). Unless otherwise noted, all modelled scenarios use the methods described in section ‎2.2. Complementing these, the REN-Hydrogen scenario also includes other vital assumptions outlined below.

| Defining characteristics of the REN-H2 scenario |
| --- |
| * Final gas demand[[26]](#footnote-27)   + To be covered mainly by renewable hydrogen by 2050   + Baseline gas demands from the BAU scenario are updated for the reduced demand implications due to the electrification effect based on EU infra. Study25 (similar to REN-Methane scenario) * Gas production and storage capacity   + Biomethane production as per existing country-specific targets specified in National energy and climate plans and other strategy documents   + Distributed (regional) biomethane production and injection in DSO & TSO lines   + Renewable hydrogen production as per country-specific technical (economically realisable) production potential (discussed and verified with each member state, see sub-section 5.2 of Deliverable 2 ‘Baseline data collection’ report)   + Hydrogen injection at transmission gas network up to 10 vol.% by 2040.   + After 2040, hydrogen will be the only gas making up 100 vol.% gas flow in the DSO & TSO lines and be the significant gaseous energy carrier in off-network gases. It is important to take in account that existing pipelines could not be used for 100% of H2 and new infrastructure + repurposing the existing NG pipelines will be needed.   + The biomethane volumes which were injected in the DSO lines before 2040, will be use as Off- Network gas after 2040.   + No additions to synthetic natural gas (SNG) capacity   + Natural gas phase out gradually till 2040.   + No further reserves of underground gas storage (i.e., only existing Inčukalns UGS   + Based on the model optimisation, off-network gas storage capacity for biomethane and hydrogen may be added. * Gas transmission   + The modelled area (3B+F): Includes existing (historical and the most recent till May 2022) pipelines and cross-border interconnectors.   + Third country: No Russian/Belarusian gas flows available after mid-2022 * LNG terminal capacities   + The modelled area includes existing and planned capacities.   + The model optimises the LNG terminal capacity based on the LNG terminal sub-annual utilisation curve given in Annex D – Technical assumptions.   + Additional required capacities may be added based on the model optimisation * ETS price projection: Based on projection data[[27]](#footnote-28) from (S&P Global 2022)20 and (REUTERS 2022)21 (Annex D) * Levelised costs of renewable electricity: Based on projection data from IRENA 202222 and Lazard 202123 (due to the low capacity factor of solar, only onshore & offshore wind power is considered – See Annex D) * Climate-neutral gas supply in 3B+F: fulfilled |

Figure ‎2‑5 illustrates the Ren-Hydrogen scenario approach for the Baltic-Finnish region. For a detailed scenario storyline, see the attached file in Annex A.

Figure ‎2‑5 Holistic vision of REN-Hydrogen scenario

Diagram

Description automatically generated

### Cost Minimal scenario

Cost Minimal scenario is similar to the REN-Methane and REN-Hydrogen scenarios, assuming a climate change mitigation ambition and carbon-neutral gas supply solution to be implemented by 2050 to enable the region to reach carbon neutrality. It is the fourth scenario modelled for Deliverable 3. It assesses the implications of the future carbon-neutral gas supply systems for Estonia and other joint gas market participant countries (Latvia, Lithuania, and Finland). The key highlight of this scenario is that it optimises the pipeline gas mix during the modelling period based on the least cost method with some specified modelling constraints. Complementing the practices described in section ‎2.2, the minimal cost scenario also includes other vital assumptions outlined below.

| Defining characteristics of Cost Minimal scenario |
| --- |
| * Final gas demand[[28]](#footnote-29)   + To be covered by biomethane, H2 (considering the technical limitation), SNG, and NG. Natural gas phase out gradually till 2040. The model will decide the pipeline fuel mix using the least cost optimisation method.   + Baseline gas demands from the BAU scenario are updated for the reduced demand implications due to the electrification effect based on EU infra. Study25 (similar to REN-Methane and REN-Hydrogen scenario) * Gas production and storage capacity   + Biomethane production as per country-specific technical (economically realisable) production potential (discussed and verified with each member state) is given as an upper cap (maximum availability of a country)   + Distributed (regional) biomethane production and injection in DSO & TSO lines   + Renewable hydrogen production as per country profiles from (FCH JU 2020)18, an average of low and high demand scenario   + Hydrogen injection at transmission gas network with a maximum cap of up to 10 vol.%   + Addition of synthetic natural gas capacity according to the need to model optimisation to fulfil the pipeline gas requirement   + No further reserves of underground gas storage (i.e., only existing Inčukalns UGS   + Off-network gas storage capacity for biomethane and hydrogen may be added based on the model optimisation * Gas transmission   + The modelled area (3B+F): Includes existing (historical and the most recent) pipelines and cross-border interconnectors.   + Third country: No Russian/Belarusian gas flows available after mid-2022 * LNG terminal capacities   + The modelled area includes existing and planned capacities.   + The model optimises the LNG terminal capacity based on the LNG terminal sub-annual utilisation curve given in Annex D – Technical assumptions.   + Additional required capacities may be added based on the model optimisation, but no utilisation of LNG terminals (LNG imports) after 2040 * ETS price projection: Based on projection data[[29]](#footnote-30) from (S&P Global 2022)20 and (REUTERS 2022)21 (Annex D) * Levelised costs of renewable electricity: Based on projection data from IRENA 202222 and Lazard 202123 (due to the low capacity factor of solar, only onshore & offshore wind power is considered – See Annex D) * Climate-neutral gas supply in 3B+F: fulfilled |

Figure ‎2‑6 illustrates the Cost Minimal scenario approach for the Baltic-Finnish region. See the attached file in Annex A for a detailed scenario storyline.

Figure ‎2‑6 Holistic vision of Cost Minimal scenario

Diagram

Description automatically generated

## Stakeholder input into modelling

Stakeholders with interest in Estonia's joint gas network were consulted throughout the development of the Deliverable 3 model. The project team solicited stakeholder feedback on the scenario definitions, input data, assumptions, and future projections. Consultations with stakeholders extended over a several months period and included representatives from the following organisations (in addition to the project steering committee from the Ministry and European Commission Directorate-General for Structural Reform Support):

* Ab Amber Grid
* Adven Eesti AS
* AS Gaasivõrk
* AS GASO
* Building Registry
* Centre for Hydrogen energy technologies, Lithuania
* Competition Authority, Republic of Estonia
* Consumer Protection and Technical Regulatory Authority, Republic of Estonia
* Elenia Lämpö
* Elering
* Energate OÜ
* Estonian Biogas association
* Estonian Energy AS
* Estonian Gas Association
* Estonian Hydrogen Association
* Estonian Industry Association
* Estonian Power and heating Association
* Estonian renewable energy association
* Finnish Biogas association
* Gasgrid Finland Oy
* Gasum Oy
* JSC Conexus Baltic Grid
* Latvian Biogas association
* Lithuanian Biogas association
* Lithuanian Energy Agency
* Ministry of Energy, Republic of Lithuania
* Ministry of Economic affairs and communication, Republic of Estonia
* Ministry of Economics, Republic of Latvia
* Ministry of Energy, Republic of Finland
* Motiva
* NR Energy OÜ
* SC Klaipėdos Nafta
* SW Energia OÜ
* UAB Intergas
* Utilitas

Table ‎2‑4 Stakeholder consultation for deliverable 3 modelling

| Date | Topic |
| --- | --- |
| June 3rd 2022 | The modelling assumption file was shared with the steering board and stakeholders as an input brief for the following meeting. |
| June 10th 2022 | Conducted the second stakeholders’ workshop for deliverable 3 to discuss and gather feedback for scenarios and modelling methodology. |
| June 11th to 26th 2022 | Bilateral enquiries were going on for data inputs, scenarios planning and modelling approaches between stakeholders & steering board members and SEI Tallinn. Meanwhile, the modelling assumption was updated with the ministry and steering board feedback. |
| June 27th 2022 | Ministry of Economics affair and communication, Republic of Estonia, invited SEI Tallinn team members to discuss scenario planning and modelling exercise. |
| June 28th 2022 | Updated Modelling assumptions and scenarios file was sent to the steering board and stakeholders to collect their feedback. |
| June 30th 2022 | Contacted the district heating association for the consumption load curve of the building sector in Estonia. |
| July 1st -11th 2022 | Feedback was received from different stakeholders for the modelling assumption and scenario file. |
| July 7th 2022 | Requested Elering - Estonian TSO for a few input data for the D3 modelling and received it on the same day. |
| July 13th 2022 | Contacted the Ministry of Energy, Republic of Lithuania for the hydrogen production numbers of Lithuania and a few inputs from them for the modelling |
| July 15th 2022 | Bilateral mail communication with Elering TSO to discuss the scenarios, modelling, and other factors to be considered in deliverable 3. |
| July 25th 2022 | The modelling team requested inputs for the modelling from the Ministry of Energy, Republic of Finland and Amber grid TSO, Lithuania. (Feedback received in 1 week) |
| July 28th 2022 – August 4th 2022 | The modelling team contacted the centre of hydrogen energy technologies in Lithuania to enquire about hydrogen consumption's current and future status. (Feedback received in 1 week) |
| August 8th 2022 | Physical meeting with the biogas association representative, Estonia. |
| August 18th-29th, 2022 | Additional input data was received from the stakeholders of all four countries. |
| August 29th, 2022 | Received comments from Estonian ministry representative for D3 scenarios assumptions |
| August 30th, 2022 | Trilateral discussion between SEI, Elering and Estonian ministry representative about the scenarios and modelling constraints |
| Sept 1st, 2022 | Bilateral discussion with Estonian ministry representative about the D3 modelling and agreed upon its scope |
| Sept 1st, 2022 | Received feedback from Conexus Baltic Grid about the Inčukalns underground gas storage feasibility of hydrogen blended gas. |
| Sept 09th, 2022 | Progress meeting with the steering board to finalize the scenario assumptions for the D3 modelling |
| Sept 12th – Oct 6th, 2022 | The modelling team built the model using the different inputs received from the steering board and stakeholders. |
| Oct 7th, 2022 | Presented the first set of results to the steering board members |
| Oct 20th, 2022 | Presented the first set of results to the stakeholders. |
| Oct 24th, 2022 | Submitted the first draft report. |
| Jan 14th, 2023 | Received the first set of feedback from the steering board member and stakeholders. |
| Feb 10th, 2023 | Submitted the second draft report with implementing all the feedbacks received from the steering board member and stakeholders. |
| April, 2023 | Submitted the final draft |

As the project team received input from stakeholders, the Deliverable 3 model was continuously revised to incorporate new information and better reflect conditions for the Baltic Finnish gas market.

# Analysis of the BAU scenario

| Key findings |
| --- |
| * NG imports as LNG will play a significant part in gas supply for the whole region through LNG terminals, and domestic renewable gas generation (biomethane and renewable hydrogen) will help reduce import dependency of the countries and the GHG impact of the region. * As per the given constraints (see section Natural Gas/LNG import from outside the RGMCG region) model presents no NG flows from GIPL to the region. * Existing Klaipeda terminal in Lithuania, FSRU in Finland and planned skulte terminal in Latvia have sufficient capacity to satisfy the region’s NG demand. * Inčukalns UGS storage levels are estimated to be maintained at approx. 50% (12-13 TWh) of its total capacity (in all years). There will be no utilisation of UGS in the years 2030, 2040 and 2050. (based on assumptions made in 2022 by taking into account only the regional needs, without external gas flows, such as from GIPL etc.) * In the BAU scenario, the average biomethane Levelised production cost in the region by 2050 is calculated as 55 EUR/MWh (highest in Estonia as 65 EUR/MWh and lowest in Latvia 45 EUR/MWh). The difference in the biomethane levelised production costs are attributable to the differences in feedstock mix per country (see Annex C) and due this consideration the technology and feedstock costs vary per country (for further explanation see section 3.9 and Biomethane feedstock availability and cost under section 2.4.3). * In the BAU scenario, the average hydrogen Levelised production cost in the region by 2050 is calculated as 102 EUR/MWh (ranging between 98-106 EUR/MWh). Within the scope of this study, the renewable hydrogen is considered to be produced only from renewable (wind onshore/offshore) electricity, the hydrogen production costs vary mainly due to the differences in the wind power capacity factor per country (see section 3.9 for more details). * By 2050, Estonia, Latvia, Lithuania, and Finland’s emissions due to the gas consumption will decrease 41%, 39%, 45% and 69%, respectively (in comparison to 2021 levels). |

## Gas supply

The diversified gas supply of each country in the BAU scenario is shown in Figure ‎3‑1. The optimised gas supply results indicate that by 2030, the majority of the region’s gas demand is to be satisfied via the existing and planned LNG terminals in the region, as no future Russian or Belarusian gas flows are available. Although each country’s domestic renewable gas production will increase over the years, NG will still continue to be the significant gaseous energy carrier by 2050. Finnish gas supply has the highest decarbonisation impact by domestic renewable gas production owing to the considerable national biomethane production targets. Lithuanian gas supply is majorly decarbonised by off-network renewable hydrogen supply for the heavy industries (fertiliser and refinery)[[30]](#footnote-31), whereas the overall gas supply of Latvia and Estonia continue to rely heavily on imported LNG in the region. As per the modelling assumptions, the existing dedicated biogas production in the region (for electricity generation) is kept constant till 2050. Consequently, all four countries will have the same biogas supplies (for direct use in electricity production) in each decade (Figure ‎3‑1, off-Network biogas). The assumption related to the dedicated biogas supply is also applied to all the other scenarios (REN-Methane, REN-Hydrogen, and Cost Minimal).

Figure ‎3‑1 BAU gas supply for the Baltic Finnish region[[31]](#footnote-32)

## Required renewable gas production capacities

On the supply side of the BAU scenario, the required combined[[32]](#footnote-33) installed capacity for biomethane production by 2050 is calculated as 910 MW in Finland, 441 MW in Lithuania, 71 MW in Latvia, and 136 MW in Estonia. The new biomethane capacity additions will be distributed across the country (in each modelled country as the biomass availability is spread across the country). The existing dedicated biogas production capacities will remain constant in all years.

The required combined installed capacity for hydrogen production (for hydrogen blending and off-network hydrogen) by 2050 is calculated as 2281 MW in Finland, 3649 MW in Lithuania, 138 MW in Latvia, and 77 MW in Estonia.

The required hydrogen installed capacities are more significant than the biomethane production capacities as biogas plants have a constant production rate and a high-capacity factor. In contrast, the electrolyser’s capacity factor is determined as per the wind energy load factor of RGMCG countries, requiring larger installed capacities to cover the peak demands. Figure 3‑2 presents the overview of the renewable gas production capacities in the region.

Figure 3‑2 BAU scenario renewable gas production capacities in Baltic Finnish region

## NG import to the region

The model had two possibilities for the future NG imports, either from the existing/planned/newly calculated LNG terminal capacities in the form of LNG or from the GIPL pipeline interconnection from Poland. The model has no import restriction on the LNG terminal module, however the plant utilisation is dictated by the plant utilisation curve, for which Klaipeda LNG terminal’s real sub-annual utilisation data for 2021 and 2022 is averaged. On the other hand, the GIPL pipeline interconnection became operational from May 2022 and has so far seen (till end of 2022) one sided gas flows (from Lithuania to Poland).

For GIPL, the model includes the constraint of using the historical gas import data for the optimisation of the future gas import. So, given the absence of the historical data on gas flows from Poland to the region, the model optimisation results indicate that there is no NG import from Poland to the RGMCG region.

As a result, there are no gas import flows from the GIPL interconnection to the region. The region imports the requisite LNG cargo quantities from the regional LNG terminal facilities. The following section provides more explanation on the LNG import.[[33]](#footnote-34)

## Role of regional LNG import infrastructure

In the BAU scenario, the regional gas market does not achieve 100% decarbonisation by 2050. Hence, the role of LNG will be significant till 2050 for all four countries.

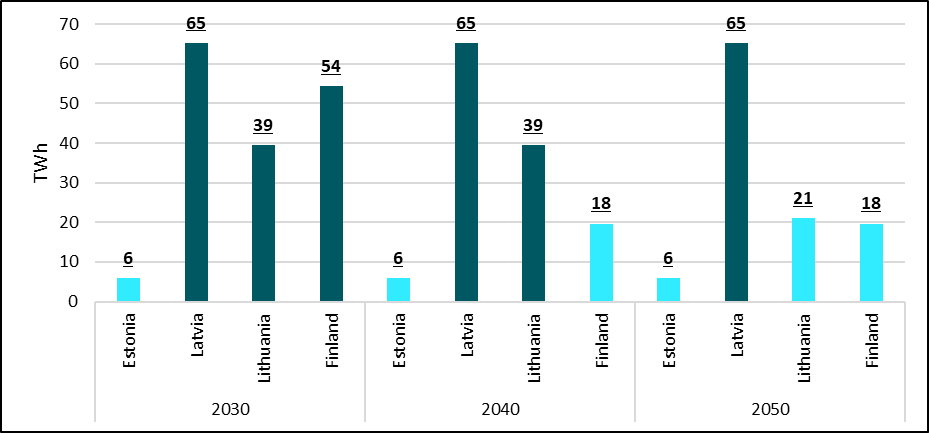
Klaipeda LNG terminal in Lithuania is connected to the transmission network in the region. From 2023 Exemplar FSRU in Inkoo Finland will provide new capacity for region, while Hamina LNG terminal in Finland, already provides additional gas supply. In 2022 the government and the parliament of the Republic of Latvia, Saeima, supported the creation of a liquefied natural gas (LNG) terminal in Skulte region. It has the status of an object of national interest and requires the terminal to be completed by the autumn of 2024. Development of Skulte LNG will be impacted by external investor financing and results of environmental impact assessment. Skulte LNG terminal is included in the model as a planned terminals for the region. As a whole, the modelling considers two existing terminals in Lithuania and Finland, and one planned LNG terminal in Latvia for the RGMCG region[[34]](#footnote-35).

As the Russian gas supplies stopped, natural gas production is not possible inside the region. Similar volumes of required NG will be imported into the region via LNG terminals. Specifically, in BAU scenario, the role of LNG terminals in the region is crucial for safeguarding security of gas supply.

Figure ‎3‑3 BAU-LNG terminal capacity of the Baltic Finnish region

**2**

**2**



Existing/Planned LNG terminals (green bars):  
**Lithuania (Klaipeda terminal):** 39 TWh, till 2044  
**Finland (Inkoo Exemplar FSRU):** 52 TWh, lease valid till 2033

Finland (Hamina): ~2 TWh, available till 2052  
**Latvia (Skulte):** 65 TWh, planned capacity available till 2054

Optimised/balancing LNG capacities (blue bars):  
**Lithuania:** 21 TWh, after Klaipeda terminal's retirement in 2044  
**Finland:** 18 TWh, after 2033 as the Exemplar FSRU lease expires  
**Estonia:** 6 TWh, early on capacity addition for optimised balancing

Modelling results reveal that until 2030, the existing/planned LNG import facilities are sufficient to balance the regional NG supplies. Hence the relatively small LNG import facility (6 TWh) in Estonia (as a result of the optimised exercise) can be avoided. To balance the Estonia’s NG demand, regional LNG terminals will supply NG to Estonia till 2050. After 2033, the lease for the Inkoo Exemplar FSRU in Finland can either be renewed or can be replaced with a relatively small capacity LNG import facility (calculated as 18 TWh as per optimisation results) which can stay operational till 2050. Finland can avoid deploying LNG receiving infrastructure capacity after 2033 by utilising the existing Klaipeda (Lithuania) and planned Skulte (Latvia) LNG terminals in the region, which are sufficient (104 TWh in total) to supply gas to Finland till 2050. As a result of scheduled retirement of Klaipeda LNG terminal in 2044, the model optimisation calculates to replace Klaipeda LNG import facility with another LNG facility which is around 21 TWh. However, due to the large existing capacity of skulte terminal in the region, this additional capacity deployment in Lithuania can also be avoided. At the same time, the natural gas demand in 2040’s will be lesser when compared to the NG demand of 2022, so the region doesn’t need to deploy any new capacity. (A more strategic sub-annual utilisation of the LNG terminals is crucial to avoid the need of additional LNG import capacities otherwise the underutilisation of LNG capacities could lead to additional required LNG capacities). As per our expert analysis and input from market experts, if Skulte LNG terminal is built as per the plan then the regional gas market will have enough capacity flexibility at sub-annual level to balance the region's (3B+F) NG demand. In that case, renewing/replacing the Finnish FSRU lease after 2033 and replacing the Klaipeda after 2044 will not be required, as regional natural gas demand will decrease over the years due to local renewable gas production growth, and deploying any new LNG receiving facility in the later years will soon result in to either stranded asset or have to be refurbished[[35]](#footnote-36) for other uses.

## Gas flow profiles

Within the BAU scenario, the total amount of gas flow between the countries in the years 2030, 2040 and 2050 is presented in the following Figure ‎3‑4[[36]](#footnote-37).

The total gas transported between the countries are the sum of sub annual gas flow (sum of monthly flows), so even if the yearly inflow and outflow of the countries appears similar at times, it does not imply that the gas transported at the sub-annual level (monthly/weekly/daily flows) is same between the countries[[37]](#footnote-38).

The overall gas demand of the region will decrease (see the attached document in Annex A for further information), and domestic gas production (from renewable hydrogen and biomethane) will help to reduce the country's reliance on annual gas imports. Modelling results show that the availability of LNG terminals in each country will result in small gas flows between the RGMCG countries for the year 2030 and 2040. As stated in the section 3.3, even though the model explicitly calculates to deploy 6 TWh and 18 TWh of LNG capacity in Estonia and Finland, the countries could avoid deploying any new LNG capacities with the better sub-annual utilisation of existing terminals. The natural gas required for Estonia and Finland will be supplied via the existing Klaipeda terminal and planned Skulte terminal[[38]](#footnote-39). In such situation, the gas flow between the region will be higher, rather than the same as indicated in the Figure ‎3‑4 for the years 2030 and 2040. By 2050, with the skulte terminal’s high available capacity will be able to supply natural gas for the whole region. The gas flow between the RGMCG countries will be even higher from Latvia to other countries in the region not as shown in the Figure ‎3‑4.

Based on the optimisation results for 2050, the net gas flow from Finland to Estonia is calculated as 0.096 TWh, from Estonia to Latvia is calculated as 1.04 TWh, from Latvia to Estonia is calculated as 0.94 TWh, from Latvia to Lithuania is calculated as 0.621 TWh, and from Lithuania to Latvia is calculated as 0.578 TWh.

Figure ‎3‑4 BAU – Gas flow profile in TWh

Map

Description automatically generated

## Storage analysis

In all scenarios, model was constrained not to add any new pipeline-connected underground gas storage capacity, but it was allowed to build any required off-network gas storage capacity (standalone storage technologies which are not directly connected to the NG network). In the model, the underground gas storage in Latvia acts as a common pipeline gas storage point for the Baltic-Finnish zone.

According to the most recent statistics on the gas storage levels in Europe revealed that the Inčukalns UGS is around 50% (September 2022) and based on the fact, the storage level of UGS in the first modelling year 2022 is considered as 50%. The model is also constrained to maintain the 50% underground storage level at the end of each modelling year for the security of supply.

The model is allowed to withdraw or inject the gaseous energy volumes during the year but the overall gas storage levels at the end of the year should be maintained at 50% level (before the peak winter months). Within the model, injection and withdrawal rates represent the gas requirement of the regional gas market (3B+F) from the UGS. Evaluation of the storage purposes outside the limits of the 3B+F region’s zone is not considered in this study. [[39]](#footnote-40)

The optimised future Inčukalns underground gas storage levels under BAU scenario considerations are presented in Figure ‎3‑5. The results show that there will be no utilisation of the UGS in 2030 and 2040 and 2050. The reason of non-utilisation of UGS is due to the significant LNG terminal capacities (Finnish FSRU, Skulte LNG terminal in Latvia, and Klaipeda LNG terminal in Lithuania) in the region. The model optimises the solution between utilising LNG terminals and having adequate storage volumes in the region.

Historically, the sub-annual utilisation of the Klaipeda LNG terminal remained significantly below its full import capabilities. In the year 2022, due to the Russian gas cut-off has showed Klaipeda terminal being utilised at its maximum levels (even in the early winter months of 2022). Following the high sub-annual availability of the regional LNG terminals, the scenario results in underutilisation of the UGS.

Figure ‎3‑5 BAU storage level of UGS at the end of each month

The optimisation results reveal that there is no off-network storage requirement for biomethane but do show the storage requirements for off-network renewable hydrogen. The following Figure ‎3‑6 depicts the hydrogen storage capacities for each country in the region. Comparatively, Lithuania and Finland require high standalone hydrogen storage capacities in the region due to the high demand for pure hydrogen for the industries.

Figure ‎3‑6 BAU – Hydrogen storage capacity

## GHG emissions

Figure ‎3‑7 illustrates the GHG impact in the BAU scenario, which assumes the region will not achieve complete gas decarbonisation by 2050. The GHG emission results show that all countries’ emissions will fall sharply due to the growth in domestic renewable gas production availability. When comparing 2050’s emissions with 2021, Estonia, Latvia, Lithuania, and Finland’s emissions decreased by around 41%, 39%, 45% and 69%, respectively. Finland’s huge emissions drop is due to their planned domestic biomethane and hydrogen production. Each country’s remaining emissions in the year 2050 are attributable mainly to NG consumption.

Figure ‎3‑7 BAU – gas related GHG emissions in the Baltic Finnish region

## Levelised costs of produced renewable gases

Figure ‎3‑8 presents the annual Levelised costs of energy production (LCOE) of the biomethane and renewable hydrogen, where they are compared with the NG price projection with and without the ETS prices. In all three decades, 2030, 2040, and 2050, Biomethane has been the most competitive gas carrier against NG. Biomethane feedstock streams like biowaste and sewage/wastewater have not been allocated any fuel cost and biomethane is considered to be produced at regional level near the availability of feedstock (avoiding additional feedstock transportation costs). If feedstock transportation costs and expenditures associated with biowaste feedstock are considered, the LCOE of biomethane will increase. Biomethane LCOE varies among countries ranging between 45-65 EUR/MWh in 2050; the difference in LCOE is caused mainly by the difference in biomethane feedstock considerations (please refer to Annex C - Feedstock mix constraints per country for biomethane production).

Renewable hydrogen’s LCOE will sharply decrease from 2030 to 2050, mainly due to the steep learning rates of the technology, and efficiency increase. By 2050, the LCOE of hydrogen for the region is ranging between 98 – 106 EUR/MWh.[[40]](#footnote-41)

Figure ‎3‑8 BAU – Comparison of LCOEs in 2030, 2040, and 2050 of the produced gases against NG prices

\*LCOE of existing off-Network biogas production is not calculated within the model

## Reasoning for difference in Levelised cost of renewable gases in the region

The difference in renewable hydrogen’s LCOE across the region in 2030 is attributable to the following reasons:

* The availability of renewable electricity for hydrogen production varies in each country as the sub-annual load factor of wind energy (onshore and offshore) in the region is different for countries within the region.
* Since Levelised cost calculation methodology is based on the overall discounted costs and the energy produced by an energy system in a time slice, the LCOE of renewable hydrogen is different for each country and depends on the overall capacity deployed and energy volumes produced in a time slice.

The difference in biomethane’s LCOE across the region in 2030 is due to the following reasons:

* Biomethane feedstock mix is different for each country. Based on the information received from the steering committee (ministry) representatives in the region, biogas association representatives and biogas reports of different countries, the biomethane feedstock availability and share of feedstock for each country is decided (please refer to Annex C - Feedstock mix constraints per country for biomethane production).
* Biomethane production system’s capital, operational and maintenance and variable costs are different as per each feedstock (For instance: Latvia is producing the cheapest biomethane in the region. The reason for this is that the major share of Latvian feedstock is from biowaste and the CAPEX, and OPEX of the anaerobic bio-digester plant is relatively less when compared to the other plants, also there is no cost considered for biowaste feedstock)[[41]](#footnote-42).

# Analysis of the REN-Methane scenario

| Key findings |
| --- |
| * The import dependency (LNG import from countries outside RGMCG) of the region will gradually decrease by 2050 (as per the NG phaseout consideration). * As per the given constraints (see section Natural Gas/LNG import from outside the RGMCG region) model presents no NG flows from GIPL to the region. * Existing Klaipeda in Lithuania, FSRU in Finland and planned skulte terminal in Latvia capacities are sufficient to satisfy the region’s NG demand. However, shifting the region’s major NG supply source from Russian pipelines to LNG terminals would reduce the regional cross border flows by 2030, but the gas flow between the countries will gradually increase by 2050 as renewable gas is integrated into the regional gas market. * Estimated Inčukalns UGS storage levels to be maintained at approx. 50% (12-13 TWh) of its total capacity (in all years). The modelling simulation shows no utilisation of UGS in the years 2030, and 2040. (Based on assumptions made in 2022 by taking into account only the regional needs, without external gas flows, such as from GIPL etc.) * In the REN-Methane scenario, the average Levelised production cost of biomethane in the region by 2050 is calculated as 52 EUR/MWh (highest in Estonia as 60 EUR/MWh and lowest in Latvia 41 EUR/MWh). The average Levelised production cost of renewable hydrogen in the region by 2050 is calculated as 101 EUR/MWh (highest in Finland as 106 EUR/MWh and lowest in Estonia as 95 EUR/MWh). The Levelised production cost of SNG for the region ranges between 128-156 EUR/MWh (lowest 128 EUR/MWh in Latvia). * Finland does not require SNG production because it’s biomethane potential and renewable hydrogen are sufficient to cover its gas demands. * By 2050, the regional gas market (3 Baltic states + Finland) will be fully decarbonised. |

## Gas supply

The diversified gas supply of each country in the REN-Methane scenario is shown in Figure ‎4‑1. The optimised gas supply results indicate that by 2030, the majority of the gas demand for the region is to be satisfied by LNG import. Over the following decades, the region’s dependency on LNG supply will decrease as each country’s domestic renewable gas production increases.

By 2050, biomethane and SNG will be the significant energy gaseous carrier produced within the region. Finland has no SNG production because its biomethane production potential is considerably high compared with its overall gas demand. In comparison to domestic biomethane production, Latvian and Lithuanian gas supply has the highest share of SNG production in the region (0.8 TWh and 0.7 TWh, respectively), whereas Estonia produces a small percentage of SNG (0.13 TWh). The existing dedicated biogas production in the region (for electricity generation) will remain constant in all years.

Figure ‎4‑1 REN-Methane – Gas supply for the Baltic Finnish region

## Required renewable gas production capacities

On the supply side of the REN-Methane scenario, the required aggregate installed capacity for biomethane production by 2050 is calculated as 1283 MW in Finland, 1074 MW in Lithuania, 407 MW in Latvia, and 357 MW in Estonia. The new biomethane capacity additions will be distributed across the country (in each modelled country as the biomass availability is spread across the country). The required SNG production capacity is calculated as 239 MW in Lithuania, 310 MW in Latvia, and 89 MW in Estonia. The model does not simulate to deploy any SNG production capacity deployment in Finland as it does not require SNG due to its high domestic biomethane production. The existing dedicated biogas production capacities will remain constant in all years.

The required combined installed capacity for hydrogen production (for hydrogen blending and off-network hydrogen) by 2050 is calculated as 1631 MW in Finland, 3715 MW in Lithuania, 182 MW in Latvia, and 90 MW in Estonia. Figure ‎4‑2 presents the overview of the renewable gas production capacities (MW) in the region.

Figure ‎4‑2 REN-Methane – Renewable gas production capacities for the Baltic Finnish region

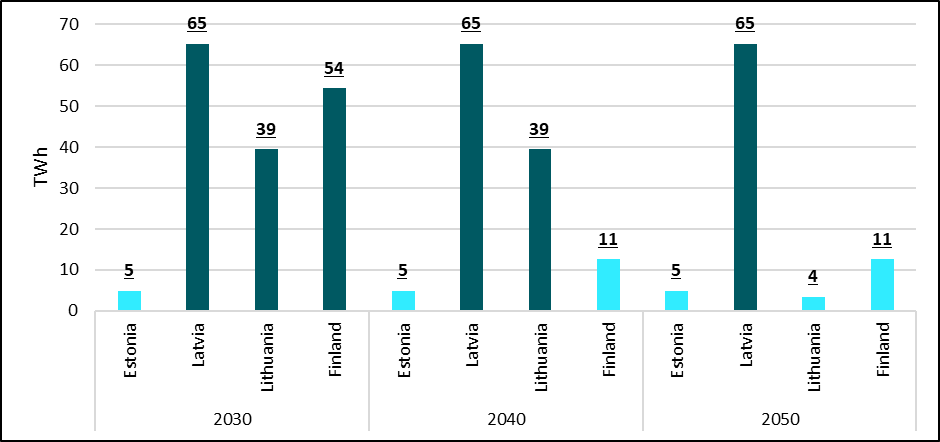
## Role of regional LNG import infrastructure

Similar to BAU scenario, the model optimises NG import via LNG terminals (as LNG) in the region, with no NG inflows from GIPL to the region (for more detail on the gas import from GIPL (Lithuania-Poland), see section ‎3.3). In the REN-methane scenario, the regional gas market is achievs 100% decarbonisation by 2050. Hence, the LNG capacity requirement for the region will gradually decrease till 2050. The BAU scenario describes in detail the existing and planned exogenous capacity of LNG terminals in Lithuania, Latvia and Finland.

Figure ‎4‑3 REN-Methane - LNG terminal capacities in the Baltic Finnish region

**2**

**2**



Existing/Planned LNG terminals (green bars):  
**Lithuania (Klaipeda terminal):** 39 TWh\_till 2044  
**Finland (Inkoo Exemplar FSRU):** 52 TWh\_lease valid till 2033

Finland (Hamina): ~2 TWh\_available till 2052  
**Latvia (Skulte):** 65 TWh\_planned capacity available till 2054

Optimised/balancing LNG capacities (blue bars):  
**Lithuania:** 4 TWh\_after Klaipeda terminal's retirement in 2044  
**Finland:** 11 TWh\_after 2033 as the Exemplar FSRU lease expires  
**Estonia:** 5 TWh\_early on capacity addition for optimised balancing   
  
**Finland:** 11 TWh\_after 2033 as the Exemplar FSRU lease expires  
**Estonia:** 5 TWh\_early on capacity addition for optimized balancing

These LNG capacities will secure the gas supply of the country/region. As the Russian gas supplies was stopped, natural gas production is not possible inside the region. Similar volumes of required NG will be imported through LNG terminals to the region. Specifically, the role of LNG terminals in the region in the early years from 2023-2030 is vital, as even with the domestic renewable gas production the scenario cannot satisfy the demand of the whole region without the support of LNG terminals. Modelling results reveal that until 2030, the existing/planned LNG import facilities are sufficient to balance the regional NG supplies. Hence the relatively small LNG import facility (5 TWh) in Estonia (as a result of the optimised exercise) can be avoided. To meet Estonia’s NG demand, the regional LNG terminals will supply NG to Estonia till 2050. After 2033, the lease for the Inkoo Exemplar FSRU in Finland can either be renewed or can be replaced with a relatively small capacity LNG import facility (calculated as 11 TWh as per optimisation results) which can stay operational till 2050. Finland can avoid deploying LNG receiving infrastructure capacity after 2033 by utilising the existing Klaipeda (Lithuania) and planned Skulte (Latvia) LNG terminals in the region, which are sufficient (104 TWh in total) to supply gas to Finland till 2050.

After 2044, as a result of the planned retirement of Klaipeda LNG terminal, the model optimisation calculates to replace Klaipeda LNG import facility with a smaller facility which is around 4 TWh and this capacity deployment can also be avoided due to the high existing capacity of the Skulte terminal in the region. (A more strategic sub-annual utilisation of the LNG terminals is crucial to avoid the need of additional LNG import capacities which could lead to underutilisation of the regional LNG import infrastructure). As per our expert analysis and input from market experts (Latvian stakeholders), if the Skulte LNG terminal is built, then the regional market will have enough capacity flexibility at sub-annual level to balance the region’s (3B+F) NG demand. In that case renewing/replacing the Finnish FSRU lease after 2033 and replacing the Klaipeda after 2044 will not be required, as regional gas is supposed to be carbon neutral after 2050 and deploying any new LNG receiving facility in the later years will soon result in to either stranded assets or assets that must be refurbished[[42]](#footnote-43) for other uses.

## Gas flow profiles

Within the REN-Methane scenario, the gas flow between the countries in the years 2030, 2040 and 2050 is presented in Figure ‎4‑4. The total gas transported between the countries are the sum of sub annual gas flow (sum of monthly flows), therefore even if the yearly inflow and outflow of the countries appears identical, it does not imply that gas transport at sub-annual level (monthly/weekly/daily flows) are same between the countries. The sub-annual gas flows between the countries are different due to the production profiles[[43]](#footnote-44) of biomethane, renewable hydrogen and SNG production systems. The sub-annual gap between domestic gas production and demand will trigger the gas flow between the countries with a high supply level to the other countries in need in the region.

According to REN-Methane scenario’s NG phaseout consideration by 2050, the region’s gas import dependency (from outside RGMCG) will decrease by 2050. Modelling results show that the availability of LNG terminals in each country will result in very low gas flows between the RGMCG countries for the year 2030 and 2040. As stated in the section 4.3, even if the model explicitly calculates to deploy additional LNG capacity in Estonia, Finland and Lithuania (due to high available LNG capacity in the region), better sub-annual utilisation of the existing/planned LNG terminals could avoid the deployment of any new LNG capacities. After 2044 except skulte and Finland’s Hamina terminal all the LNG capacities will be retired, and any natural gas required for the region will be supplied mainly from planned skulte terminal and Hamina terminal[[44]](#footnote-45). In that case, the flow between the RGMCG countries will be higher than the illustrated flows in the Figure ‎4‑4.

By 2050, due to the complete decarbonisation of the regional gas mix, the net gas flows between the countries can be seen to increase as depicted in the Figure ‎4‑4. In 2050, the net gas flow between Finland and Estonia is calculated as 1.79 TWh, between Estonia and Latvia is calculated as 2.26 TWh, and between Latvia and Lithuania is calculated as 1.12 TWh. These bi-directional annual net gas flows in 2050 are almost equal in energy content. However, this should not be confused with no net annual consumption, as these flows are calculated by adding up the sub-annual flows between the countries in order to balance the sub-annual gap between renewable domestic gas production and gas demand.

Figure ‎4‑4 REN-Methane – Gas flow profile in TWh

Map

Description automatically generated

## Storage analysis

The key explanation on the UGS optimisation is presented in the storage analysis under BAU scenario. The key points remain the same across all the scenarios.

The optimised future Inčukalns underground gas storage levels under REN-Methane scenario considerations are presented in Figure ‎4‑5. The results present that the utilisation of the UGS is very low to none in 2030 and 2040 and is approximately 4 TWh in 2050. The reason for non-utilisation of UGS in 2030 and 2040 is the because of the region’s substantial LNG terminal capacities (Finnish FSRU, Skulte LNG terminal in Latvia, and Klaipeda LNG terminal in Lithuania). Historically, the sub-annual utilisation of the Klaipeda LNG terminal remained significantly below its full import capability, but due to the Russian gas cut-off in 2022, Klaipeda terminal is being utilised at its maximum capacity level (even in the early winter months of 2022). Following the high sub-annual availability of the regional LNG terminals, the scenario results in underutilisation of the UGS. The approximately 4 TWh of UGS utilisation in 2050 is attributed to the sub-annual renewable gas injection and withdrawal (injection during summer when the demand is less, and the production exceeds the demands and utilisation in winter when demand exceeds the production).

Figure ‎4‑5 REN-Methane storage level of UGS at the end of each month

The optimisation results indicate that there is no off-network storage requirement for biomethane, but it does show the need for off-network renewable hydrogen storage. The following Figure ‎4‑6 depicts the hydrogen storage capacities (in MW and TWh) for each country in the region. Comparatively, Lithuania and Finland require high standalone hydrogen storage capacities in the region due to the high demand for pure hydrogen in the industries.

Figure ‎4‑6 REN Methane - Hydrogen storage capacity

## GHG emissions

Figure ‎4‑7 illustrates the GHG impact in the REN-Methane scenario, which assumes the region will achieve complete gas decarbonisation by 2050. The GHG emission results show that gas consumption related emissions in all four countries will fall sharply when domestic renewable gas production expands to cover total national gas demands of each country.

Figure ‎4‑7 REN-Methane – gas related GHG emissions in the Baltic Finnish region

## REN-Methane scenario - Levelised costs of produced renewable gases

Figure ‎4‑8 presents the comparison of annual Levelised costs of energy production (LCOE) of biomethane, SNG and renewable hydrogen to the NG price projection with and without the ETS prices.

In all three decades, 2030, 2040, and 2050, Biomethane has been the most competitive gas carrier against NG. According to the feedstock considerations, biomethane LCOE in 2050 should range between 41-60 EUR/MWh in RGMCG region. Renewable hydrogen's LCOE will sharply decrease from 2030 to 2050, mainly due to the steep learning rates of the technology, efficiency increase, and significant overall production volumes. When the efficiency of the hydrogen production technology increases automatically it will reflect in the increase of SNG efficiency since hydrogen is the feedstock of SNG production. For 2050, LCOE of renewable hydrogen and SNG ranges between 95-106 EUR/MWh and 128-156 EUR/MWh, respectively. There is no cost assigned for SNG in Finland since the biomethane potential of Finland, along with renewable hydrogen, is enough to cover its gas demands. The reasoning for different production cost of different gaseous fuels for each country in the region are explained in the BAU scenario (please refer to section 3.9).

Figure ‎4‑8 REN-Methane - Comparison of LCOEs in 2030, 2040 and 2050 of the produced gases against NG prices

\*LCOE of existing off-Network biogas production is not calculated within the model

# Analysis of the REN-Hydrogen scenario

| Key findings |
| --- |
| * The import dependency (LNG import from countries outside RGMCG) of the region will gradually decrease by 2050 (as per the NG phaseout consideration). * As per the given constraints (see section Natural Gas/LNG import from outside the RGMCG region) model presents no NG flows from GIPL to the region. * Existing Klaipeda in Lithuania, FSRU in Finland and planned skulte terminal in Latvia capacities are sufficient to satisfy the region’s NG demand. * Estimated Inčukalns UGS storage levels to be maintained at approx. 50% (12-13 TWh) of its total capacity (in all years). There will be no utilisation of UGS in the years 2030, 2040 and 2050. (based on assumptions made in 2022 by taking into account only the regional needs, without external gas flows, such as from GIPL etc.) * In the REN-Hydrogen scenario, the average Levelised production cost of biomethane in the region by 2050 is calculated as 57 EUR/MWh (highest in Estonia as 68 EUR/MWh and lowest in Latvia 46 EUR/MWh). The average Levelised production cost of renewable hydrogen in the region by 2050 is calculated as 96 EUR/MWh (highest in Finland as 107 EUR/MWh and lowest in Latvia as 86 EUR/MWh). * By 2050, the regional gas market (3 Baltic States + Finland) will achieve decarbonisation. * By 2040, The existing gas pipelines in the region will be repurposed and/or dedicated hydrogen pipelines will be built for pure renewable hydrogen supply in the RGMCG countries. End-use equipment replacement requirement applies. |

## Gas supply

The diversified gas supply of each country in the REN-Hydrogen scenario is shown in Figure ‎5‑1. The optimised gas supply results indicate that till 2040, the majority of the gas demand for the region is to be supplied by LNG import. Until 2040, the pipeline gas is mainly decarbonised with limited biomethane and renewable hydrogen supply. After 2040, the model stops supplying LNG to the region, as by 2041, hydrogen will become the significant gaseous carrier.

Off-network hydrogen supply will constantly increase till 2040 and then remains constant from 2041. There will be no biomethane injections in the pipeline after 2040, but equal amounts will be utilised in the off network till 2050. The existing dedicated biogas production in the region (for electricity generation) will remain constant in all years.

Figure ‎5‑1 REN-Hydrogen – Gas supply of the Baltic Finnish region

## Required renewable gas production capacities

On the supply side of the REN-Hydrogen scenario, the required combined installed capacity for hydrogen production (for hydrogen blending and off-network hydrogen) by 2050 will be 3 432 MW in Finland, 7 348 MW in Lithuania, 1 209 MW in Latvia, and 1923 MW in Estonia.

The required combined installed capacity for biomethane production by 2050 is calculated as 598 MW in Finland, 284 MW in Lithuania, 52 MW in Latvia, and 109 MW in Estonia. The new biomethane capacity additions will be spread across the country (in each modelled country as the biomass availability is spread across the country). Figure ‎5‑2 presents the overview of the renewable gas production capacities (MW) in the region. The existing dedicated biogas production capacities will remain constant in all years.

Figure ‎5‑2 REN-Hydrogen – renewable gas production capacity in the Baltic Finnish region

## Role of LNG import infrastructure

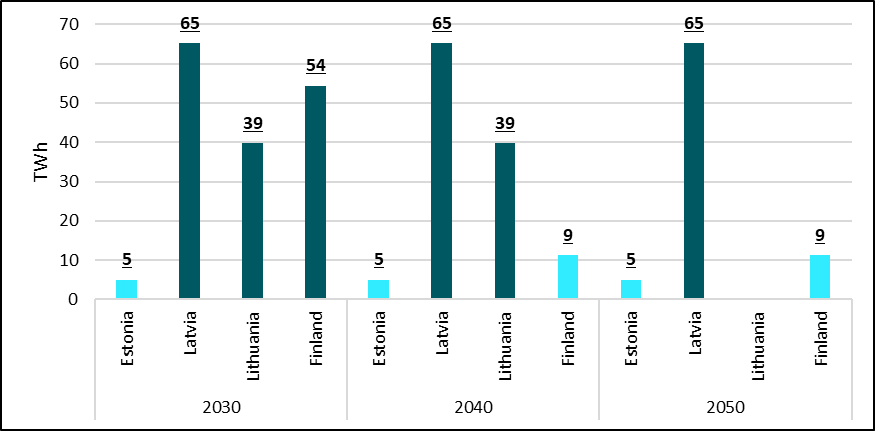
Similar to the BAU scenario, the model optimises NG imports via LNG terminals (as LNG) in the region, with no NG inflows from GIPL to the region (for more detail on the gas import from GIPL (Lithuania-Poland), see section ‎3.3).

In the REN-Hydrogen scenario, the regional gas market is achieving 100% decarbonisation by 2050. The role of LNG capacities will gradually decrease till 2040 for all four countries. The BAU scenario describes in detail the existing and planned capacity of LNG facilities in Lithuania, Latvia, and Finland.

Figure ‎5‑3 REN-Hydrogen – LNG terminal capacity of the Baltic Finnish region

**2**

**2**



Existing/Planned LNG terminals (green bars):  
**Lithuania (Klaipeda terminal):** 39 TWh\_till 2044  
**Finland (Inkoo Exemplar FSRU):** 52 TWh\_lease valid till 2033

Finland (Hamina): ~2 TWh\_available till 2052  
**Latvia (Skulte):** 65 TWh\_planned capacity available till 2054

Optimised/balancing LNG capacities (blue bars):  
**Finland:** 9 TWh\_after 2033 as the Exemplar FSRU lease expires  
**Estonia:** 5 TWh\_early on capacity addition for optimised balancing

Modelling results reveal that until 2030, the existing/planned LNG import facilities are sufficient to balance the regional NG supplies. Hence the relatively small LNG import facility (5 TWh) in Estonia (as a result of the optimised exercise) can be avoided. To balance the NG demand of Estonia, the regional LNG terminals will supply NG to Estonia till 2040. After 2033, the lease for the Inkoo Exemplar FSRU in Finland can be renewed for next 7 years (calculated as 11 TWh as per optimisation results) which can stay operational till 2040. Finland can avoid deploying LNG receiving infrastructure capacity after 2033 by utilising the region’s existing Klaipeda (Lithuania) and planned Skulte (Latvia) LNG terminals, which are sufficient (104 TWh in total) to supply gas to Finland till 2040. After 2044, as a result of the planned retirement of Klaipeda LNG terminal, the model optimisation calculates not to deploy any new capacities since the region will be completely decarbonised by 2040 (A more strategic sub-annual utilisation of the LNG terminals is crucial to avoid the need for additional LNG import capacities which could lead to underutilisation of the regional LNG import infrastructure).

According to our expert analysis and input from market experts, if existing Klaipeda LNG terminal and planned Skulte LNG terminal are operational, the regional market will have sufficient capacity flexibility at sub-annual level to balance the region's (3B+F) NG demand. In that case renewing/replacing the Finnish FSRU lease after 2033 will not be required, as regional gas is supposed to be carbon neutral by 2040 and deploying any new LNG receiving facility in the later years will soon result in to either stranded assets or assets that have to be refurbished37 for other uses.After 2040, the unused LNG terminal can be used to import hydrogen derivatives, for which the necessary refurbishment of the LNG infrastructure will be required.

## Gas flow profiles

Within REN- Hydrogen scenario, the gas flow between the countries in the years 2030, 2040 and 2050 is presented in the following Figure ‎5‑4[[45]](#footnote-46).

In the REN-Hydrogen scenario, by 2041, 100% of the pipeline gas is to be constituted on renewable hydrogen. Hence the import dependency (LNG or NG import from a country outside RGMCG) of the region will diminish by 2040. Modelling results shows that the availability of LNG terminals in each country will result in very low gas flows between the RGMCG countries in 2030, 2040 and 2050. As stated in the section 5.3, even if the model explicitly calculates to deploy 5 TWh and 11 TWh of LNG capacity in Estonia and Finland, due to region’s high available LNG capacity, Estonia and Finland could avoid deploying any new LNG capacities with better sub-annual utilisation of the Klaipeda and Skulte LNG terminals. In that case the flow between the RGMCG region will be higher than the flows shown in the Figure ‎5‑4. The natural gas required for the countries are stated in the section 5.1.

The net gas flow between the RGMCG countries can be seen in the Figure ‎5‑4. In 2050, the net gas flow from Finland to Estonia is calculated as 0.096 TWh, from Estonia to Finland is calculated as 1.34 TWh, from Latvia to Estonia is calculated as 1.192 TWh, and from Lithuania to Latvia is 1.056 TWh.

Figure ‎5‑4 REN-Hydrogen - Gas flow analysis in TWh

Map

Description automatically generated

## Storage analysis

The key explanations on the UGS optimisation are presented in the storage analysis under BAU scenario. The key points are consistent across all scenarios.

The optimised future Inčukalns underground gas storage levels under REN-Hydrogen scenario considerations are presented in Figure ‎5‑5.The optimised future storage levels are presented in Figure ‎5‑5. The results present that the utilisation of the UGS is very low to none in 2030 and 2040 and 2050. The reason of non-utilisation of UGS is due to the existence of sufficient LNG terminal capacities (Finnish FSRU, Skulte LNG terminal in Latvia, and Klaipeda LNG terminal in Lithuania) in the region. Historically, the sub-annual utilisation of the Klaipeda LNG terminal remained significantly below its full import capability, however the year 2022, due to the Russian gas cut-off showed Klaipeda terminal being utilised at its maximum levels (even in the early winter months of 2022). Following the high sub-annual availability of the regional LNG terminals, the scenario results in underutilisation of the UGS.

Figure ‎5‑5. REN-Hydrogen – storage level at the end of the month in UGS

The optimisation results indicates that there is no off-network storage requirement for biomethane, but it does show the storage requirements for off-network renewable hydrogen. The following Figure ‎5‑6 depicts the hydrogen storage capacities for each country in the region. Comparatively, Lithuania and Finland require high standalone hydrogen storage capacities in the region due to the high demand for pure hydrogen for the industries.

Figure ‎5‑6 REN- Hydrogen - Hydrogen storage capacity

## GHG emissions

Figure ‎5‑7 illustrates the GHG impact in the REN-hydrogen scenario, which assumes the region will achieve complete gas decarbonisation by 2050. The GHG emission results show that gas related emissions in all four countries will fall sharply due to the growth in the availability of domestic renewable gas production to cover total national demands. The countries will be decarbonised by 2040 since all the pipeline and off-network gas are majorly based on renewable hydrogen supply.

Figure ‎5‑7 GHG emissions- gas related in the Baltic Finnish region

## Levelised costs of produced renewable gases

Figure ‎5‑8 presents the annual levelised energy production costs (LCOE) of the renewable hydrogen and biomethane, where they are compared with the NG price projection with and without the ETS prices.

Figure ‎5‑8 REN-Hydrogen - Comparison of LCOEs in 2030, 2040, and 2050 of the produced gases against NG prices

\*LCOE of existing off-Network biogas production is not calculated within the model

Renewable hydrogen's LCOE will sharply decrease from 2030 to 2050, mainly due to the steep learning rates of the technology, efficiency increase, and significant overall production volumes. By 2050, the LCOE in the region will range between 95-107 EUR/MWh.

In all three decades, biomethane is found to be the most competitive gas carrier against NG. As per the feedstock considerations, the LCOE of biomethane is different in the considered countries ranging between 46-68 EUR/MWh in 2050. There is no cost assigned for SNG in the region since there will be no production.

The reasoning for different production cost of different gaseous fuels for each country in the region are explained in the BAU scenario (please refer to section ‎3.9).

# Analysis of Cost Minimal scenario

| Key findings |
| --- |
| * The region's import dependency (LNG or NG import from countries outside RGMCG) will diminish by 2040. * As per the given constraints (see section Natural Gas/LNG import from outside the RGMCG region) model presents no NG flows from GIPL to the region. * Existing Klaipeda in Lithuania, FSRU in Finland and planned Skulte LNG terminal in Latvia capacities are sufficient to satisfy the region’s NG demand. * Estimated Inčukalns UGS storage levels to be maintained at approx. 50% (12-13 TWh) of its total capacity (in all years). There will be no utilisation of UGS in the years 2030. (Based on assumptions made in 2022, by taking into account only the regional needs, without external gas flows, such as from GIPL etc.) * Country-specific biomethane potential will be deployed in the early years till 2030. * In the Cost Minimal scenario, the average Levelised production cost of biomethane in the region by 2050 is calculated as 53 EUR/MWh (highest in Lithuania as 58 EUR/MWh and lowest in Latvia as 43 EUR/MWh). The average Levelised production cost of renewable hydrogen in the region by 2050 is calculated as 121 EUR/MWh (highest in Latvia as 139 EUR/MWh and lowest in Lithuania as 108 EUR/MWh). In Cost Minimal scenario, the model did not choose to deploy SNG production in Estonia, Latvia, and Finland. As per the results, Lithuania is the only country in the region with SNG production, and the model optimisation showed that 2046 is the last year of SNG production in Lithuania with an LCOE of 153 EUR/MWh. * The emission in all the counties will decrease sharply (under 0.2-million-ton CO2eq.) by 2030, and eventually, the regional gas market (3B+F) will become carbon neutral. |

## Gas supply

The diversified gas supply of each country in the cost-minimal scenario is shown in Figure 6‑1. After 2030, most of the gas demand for the region is to be satisfied via domestic renewable gas production. The results of the least cost method present that all countries in the region by 2030 will utilise their maximum biomethane production potential, and the production will remain constant over the following decades.

By 2030 to 2040, the model optimised that the region’s reliance on LNG would diminish, and biomethane will be the significant gaseous energy carrier in each country.

Based on the analysis, Finland has 11 TWh of economically realisable biomethane production potential per year and it only requires around 9 TWh per year. In this case, to offset the domestic production shortfall in neighbouring countries like Latvia and Lithuania (where biomethane production potential is lacking), Finland will produce excess biomethane. The excess gas production in the RGMCG region can be transmitted via transmission pipeline to balance the supply requirement within the region. The results show that SNG production will be limited to Lithuania. The existing dedicated biogas production in the region (for electricity generation) will remain constant in all years.

In 2050, based on the least cost optimisation, the model resulted not to blend hydrogen and SNG in the gas pipelines. As there is no technical limitation for producing off-network (pure) hydrogen, the production of off-network pure hydrogen will gradually increase over the years.

Figure ‎6‑1 Cost minimal – gas supply of Baltic Finnish region

## Required renewable gas production capacities

On the supply side of the cost-minimal scenario, the required combined installed capacity for biomethane production by 2050 is calculated as 1 497 MW in Finland, 1 074 MW in Lithuania, 363 MW in Latvia, and 357 MW in Estonia. The new biomethane capacity additions will be spread across the country (in each modelled country as the biomass availability is spread across the country). The installed capacity of SNG production in Lithuania is 1 031 MW. The existing dedicated biogas production capacities will remain constant in all years.

The required combined installed capacity for hydrogen production (for hydrogen blending and off-network hydrogen) by 2050 is calculated as 2 689 MW in Finland, 3 783 MW in Lithuania, 242 MW in Latvia, and 200 MW in Estonia49. Figure ‎6‑2 presents the overview of the renewable gas production capacities in the region.

Figure ‎6‑2 Cost minimal – Renewable gas production capacities of the Baltic Finnish region

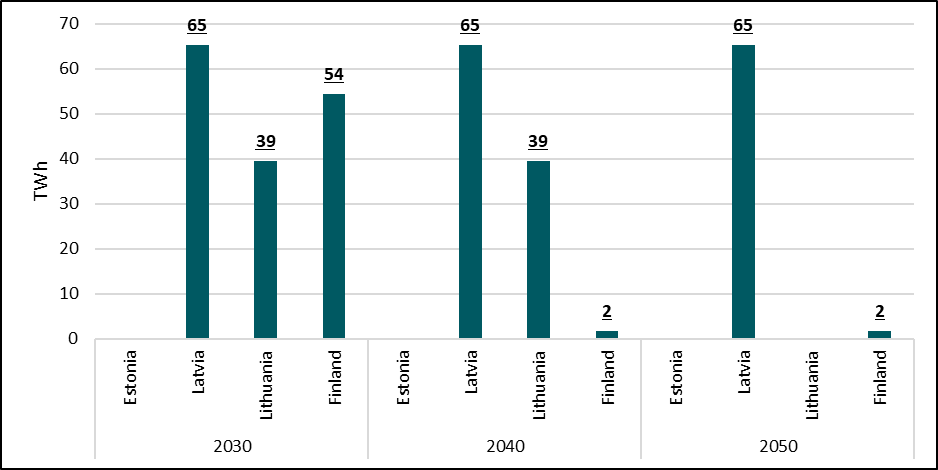
## Role of LNG import infrastructure

The model, like the BAU scenario, optimises NG import via LNG terminals (as LNG) in the region, with no NG inflows from GIPL to the region (for more detail on the gas import from GIPL (Lithuania-Poland), see section ‎3.3).

In the cost minimal scenario, the regional gas market is achieving 100% decarbonisation by 2050; hence there will be no role for LNG terminals by 2050. The existing and planned capacity of LNG terminals in Lithuania, Latvia and Finland are explained in detail in the BAU scenario.

Based on the cost optimisation, the modelling results show that there will be no additional LNG terminal capacity deployment in a cost-minimal scenario. The results show that in 2050, Latvia and Finland will have some available capacities, but they will not be functional to import fossil LNG[[46]](#footnote-47).

Figure ‎6‑3 Cost minimal – LNG terminal capacity of the Baltic Finnish region



Existing/Planned LNG terminals (green bars):  
**Lithuania (Klaipeda terminal):** 39 TWh\_till 2044  
**Finland (Inkoo Exemplar FSRU):** 52 TWh\_lease valid till 2033

Finland (Hamina LNG terminal): ~2 TWh\_available till 2052  
**Latvia (Skulte):** 65 TWh\_planned facility available till 2054

## Gas flow profiles

Within cost minimal scenario, the gas flow between the countries in the years 2030, 2040 and 2050 is presented in the following Figure ‎6‑4[[47]](#footnote-48). The import dependency (LNG or NG import from a country outside RGMCG) of the region will diminish by 2040. In 2030, the gas flow between the countries is quite low, owing to the region’s high NG demand and high LNG availability.

The complete decarbonisation of the regional gas mix by 2040 and 2050 will increase the net gas flow between the countries. In 2050, the net gas flow from Finland to Estonia is calculated as 3.92 TWh, from Estonia to Finland is calculated as 0.47 TWh, from Latvia to Estonia is calculated as 0.95 TWh, from Estonia to Latvia is calculated as 4.34 TWh, and from Latvia to Lithuania is 2.56 TWh.

According to the modelling results, Lithuania will be a net importer in the region in 2050, with net inflows of 2.56 TWh, and no net outflow outside the country. This is because the biomethane capacity (partial capacities around 1 TWh) in Lithuania completes their lifetime by 2047, and based on the cost optimisation method, the model opted to start importing the gas instead of building new biomethane capacities in Lithuania. The excess biomethane production from Finland is exported to Lithuania to satisfy the Lithuanian demand requirement.

Figure ‎6‑4 Cost minimal – Gas flow profiles in TWh

Map

Description automatically generated

## Storage analysis

The key explanations on the UGS optimisation are presented in the storage analysis under BAU scenario. The key points remain consistent across all scenarios.

The optimised future Inčukalns underground gas storage levels under Cost Minimal scenario considerations are presented in Figure ‎6‑5. The results present that there is no utilisation of the UGS in 2030. The reason of non-utilisation of UGS is due to the large LNG terminal capacities (Finnish FSRU, Skulte LNG terminal in Latvia, and Klaipeda LNG terminal in Lithuania) in the region. Utilisation of UGS in Latvia is higher in 2040 and 2050 than in 2030, this is due to the region’s complete decarbonisation through the production of renewable gases. Since the region started producing high REN gases such as biomethane, hydrogen and SNG, the production curves of each gaseous fuels in each country are different, therefore excess renewable gas will be stored in the UGS and utilised later when it is needed. By 2040 and 2050 the UGS is utilised around 4-5 TWh.

Figure ‎6‑5 Cost minimal – storage level of UGS at the end of each month

The optimisation results of the injection and withdrawal rate of the Inčukalns UGS in Latvia are shown in Figure ‎6‑6. In 2040, the total injection is 4.70 TWh and withdrawal is 4.6 TWh, and while total injection is 3.4 TWh and withdrawal is 3.3 TWh in 2050.

Figure ‎6‑6 Cost minimal – injection and withdrawal of UGS in Latvia

The optimisation results indicate that there is no off-network storage requirement for biomethane, but it does show the storage requirements for off-network renewable hydrogen. The following Figure ‎6‑7 depicts the hydrogen storage capacities for each country in the region. Comparatively, Lithuania and Finland require high standalone hydrogen storage capacities in the region due to the high demand for pure hydrogen for the industries.

Figure ‎6‑7 Cost minimal - Hydrogen storage capacity

## GHG emissions

Figure ‎6‑8 illustrates the GHG impact in the cost minimal scenario, which assumes that the region will achieve complete gas decarbonisation by 2050. The GHG emission results show that the gas related emissions in all emissions will fall sharply when domestic renewable gas production expands to cover total national demands.

The emissions in all the counties will decrease sharply by 2030, and by 2050 the regional gas market (3B+F) will become carbon neutral (nearly 0-million-ton CO2eq.).

Figure ‎6‑8 Cost minimal – gas related GHG emissions in the Baltic Finnish region

## Levelised costs of produced renewable gases

Figure ‎6‑9 presents the annual Levelised costs of energy production (LCOE) of the biomethane, SNG and renewable hydrogen where they are compared with the NG price projection with and without the ETS prices.

In all three decades, 2030, 2040, and 2050, Biomethane has been the most competitive gas carrier against NG. As per the feedstock considerations, biomethane LCOE is different in different countries ranging between 43-58 EUR/MWh in 2050.

Renewable hydrogen's LCOE will sharply decrease from 2030 to 2050, mainly due to the steep learning rates of the technology, efficiency increase, and significant overall production volumes. By 2050, the LCOE of renewable hydrogen ranges between 108-139 EUR/MWh.

Modelling results indicate that SNG production requirement is only in Lithuania. There is no cost assigned for SNG in Estonia, Latvia and Finland since the optimisation results did not result in SNG production in these countries. The model optimisation showed that 2046 is the last year of SNG production in Lithuania, with an LCOE of 153 EUR/MWh.

The reasoning for different production cost of different gaseous fuels for each country in the region are explained in the BAU scenario (please refer to section 3.9).

Figure ‎6‑9 Cost minimal - comparison of LCOEs in 2030, 2040, and 2050 of the produced gases against NG prices

\*LCOE of existing off-Network biogas production is not calculated within the model

# Result comparison across pathways

| Key findings |
| --- |
| * Driven by the Russian/Belarusian gas supply cut, LNG terminals will play a significant role in the gas supply for the whole region until 2040. * Based on the given modelling constraints (see section Natural Gas/LNG import from outside the RGMCG region) model presents no NG flows from GIPL to the RGMCG region and the region is dependent on regional LNG import infrastructure for the NG supply, as per the modelling results. * In the BAU scenario, LNG imports will remain a significant part of the gas supplies in RGMCG countries by 2050. In other modelled scenarios, domestic renewable gas production will gradually replace the imported NG (via LNG imports) over the decades till 2050. (See Table ‎7‑1). * Except Cost Minimal scenario, optimisation results indicate that small LNG receiving capacities in the region (additional to the existing or planned infrastructure) are required, Table ‎7‑2. (*To calculate LNG capacity, the model is optimised based on the sub-annual utilisation curve of the Klaipeda LNG terminal for the years 2021/2022 (average of both years) and this utilisation curve is used for all the existing and planned terminals in the model – See Annex D*). * However, these additional optimised LNG capacities are not necessarily to be deployed. Based on the expert analysis, the existing terminals (Klaipeda LNG terminal Lithuania, FSRU and Hamina LNG terminal in Finland) and planned Skulte LNG terminal in Latvia are sufficient to cover the region’s estimated NG demand. (See Table ‎7‑2 & Table ‎7‑5). * In Cost Minimal scenario, the model estimated that existing and planned LNG terminal capacities are sufficient for the region's NG demand because optimisation results show that the country-specific biomethane potential will be deployed in the early years till 2030 (reducing the overall fossil gas demands). * Gas volume exchange between the 3B+F nations is conceivable in all scenarios at the sub-annual level via transmission lines and allowing each country's access to Latvian UGS. But, due to high availability of LNG terminals in the region, the UGS in most scenario cases is underutilised. Based on the modelling results and the scope of the analysis, Inčukalns UGS utilisation for the regional demand may decrease, but may not in the wider scope, considering the future gas need of EU countries, use of GIPL interconnection, countries outside RGMCG region may have the chance to utilise the UGS in Latvia. * In all the scenarios, the model estimated that Inčukalns UGS storage levels would be maintained at approx. 50% (12-13 TWh) of its total capacity (in all years) for the energy security of the region. However, the sub-annual utilisation (injection/withdrawal) profiles and total yearly utilised energy volumes vary across all scenarios. * The modelling results show a storage requirement for off-network renewable hydrogen (stored as LOHC in surface LOHC tanks) but not for off-network biomethane. Comparatively, Lithuania and Finland require high standalone hydrogen storage capacities in the region due to the high demand for pure hydrogen for the large industries (fertilizer and refineries). Model optimisation results shows that REN-Hydrogen scenario will need the highest hydrogen storage capacities among all scenarios by 2050; Estonia (4.6 GWh), Latvia (5.1 GWh), Lithuania (68.1 GWh), and Finland (151.3 GWh). * In the BAU scenario, the average biomethane Levelised production cost in the region by 2050 is calculated as 54 EUR/MWh (highest in Estonia as 65 EUR/MWh and lowest in Latvia 45 EUR/MWh). The difference in the biomethane Levelised production costs are due to the difference in feedstock mix per country (see Annex C) and as a result, technology and feedstock costs vary by country( for further explanation see section ‎3.9 and Biomethane feedstock availability and cost under section 2.4.3). * In the BAU scenario, the average hydrogen Levelised production cost in the region by 2050 is calculated as 102 EUR/MWh (ranging between 98-106 EUR/MWh). Within the scope of this study the renewable hydrogen is considered to be produced only from renewable (wind onshore/offshore) electricity, with hydrogen production costs varying mainly due to the differences in wind power load factor per country (see section 3.9 for more details). * In the REN-Methane scenario, the average Levelised production cost of biomethane in the region by 2050 is calculated as 52 EUR/MWh (highest in Estonia as 60 EUR/MWh and lowest in Latvia 41 EUR/MWh). The average Levelised production cost of renewable hydrogen in the region by 2050 is calculated as 101 EUR/MWh (highest in Finland as 106 EUR/MWh and lowest in Estonia as 95 EUR/MWh). The Levelised production cost of SNG for the region ranges between 128-156 EUR/MWh (lowest 178 EUR/MWh in Latvia). Finland has no SNG production due to high biomethane potential availability within the country, along with renewable hydrogen, is sufficient to cover its national gas demands. * In the REN-Hydrogen scenario, the average Levelised production cost of biomethane in the region by 2050 is calculated as 57 EUR/MWh (highest in Estonia as 68 EUR/MWh and lowest in Latvia 46 EUR/MWh). The average Levelised production cost of renewable hydrogen in the region by 2050 is calculated as 96 EUR/MWh (highest in Finland as 107 EUR/MWh and lowest in Latvia as 86 EUR/MWh). * In the Cost Minimal scenario, the average Levelised production cost of biomethane in the region by 2050 is calculated as 53 EUR/MWh (highest in Lithuania as 58 EUR/MWh and lowest in Latvia as 43 EUR/MWh). The average Levelised production cost of renewable hydrogen in the region by 2050 is calculated as 121 EUR/MWh (highest in Latvia as 139 EUR/MWh and lowest in Lithuania as 108 EUR/MWh). In Cost Minimal scenario, the model did not choose to deploy SNG production in Estonia, Latvia, and Finland. According to the results, Lithuania is the only country in the region with SNG production, and the model optimisation revealed that 2046 will be the last year of SNG production in Lithuania, with an LCOE of 153 EUR/MWh. * GHG emissions due to fossil gas consumption will decrease in the region, as a result of the integration of domestic renewable gases. In the BAU scenario, by 2050, Estonia, Latvia, Lithuania, and Finland’s emissions from gas consumption will decrease 41%, 39%, 45% and 69% lower than in 2021. * All the other scenarios achieve full decarbonisation by 2050. Cost Minimal scenario achieves the fastest decarbonisation of all scenarios as emissions decrease sharply (under 0.2-million-ton CO2eq.) by 2030, and eventually, the regional gas market (3B+F) becomes carbon neutral. This occurred because the model chose to deploy (based on the least cost method) the large capacities of biomethane in the early years (by 2030). |

This section compares the modelled scenarios' key results, highlights, and synoptic insights from the Deliverable three modelling. A cross-scenario comparison of gas supply, LNG capacities, and the Levelised costs of the produced gases are given in Table ‎7‑1, Table ‎7‑2, and Table ‎7‑3, respectively.

Table ‎7‑1. Gas supply of the Baltic-Finnish region

|  |  |
| --- | --- |
|  |  |
|  |  |

Table ‎7‑2. Role of LNG import infrastructure in the Baltic-Finnish region (dark blue bars: Existing or planned capacities, red bars: Additional optimised capacities)

|  |  |
| --- | --- |
|  |  |
|  |  |

Table ‎7‑3. Comparison of Levelised cost of produced renewable gases against NG prices for the Baltic-Finnish region

|  |  |
| --- | --- |
|  |  |
|  |  |

## Gas supply

The optimisation results of the scenario modelling provide different sets of solutions to the countries within the RGMCG region. It is worth noting that all four countries are a part of the regional gas market, therefore they are connected via transmission pipelines. The model represents the same effect, which means that imported LNG and gases injected into pipelines can be transported from one country to another via a transmission line.

Table ‎7‑1 shows the country-specific gas supply in each scenario. Comparing the gas supply of different countries and scenarios. Each scenario has different gas as their primary gas energy carrier. Based on the model findings, all the countries in the BAU scenario will be majorly dependent on LNG import gases by 2030 and 2050. When the supply of LNG import gases is compared to the required demand by 2050, Estonia and Latvia are the countries which hold the highest share of LNG import gases. The reason is, that countries produce less domestic renewable gas (2030 NECP’s target), so the LNG dependency is high.

In the methane scenario, the results indicate that, despite the countries massive requirement for LNG by 2030, the main goal of the scenario is to achieve producing the maximum feasible biomethane potential by 2050. The optimised results indicate that the majority of the gas supply in the region is biomethane and SNG. Based on the biomethane availability and the country's national gas demand, SNG will be produced for each country to meet the demand gap.

The results of REN-hydrogen scenario show that by 2040 gas supplies in all four countries will be significantly reliant on LNG gas imports. By 2041, gas pipelines will supply 100% renewable hydrogen, and biomethane capacities which are used for pipeline blending before 2040 will be available off-network from 2041. Biomethane for pipeline blending will be provided as off-network from 2041. These results are consistent across all the countries in the RGMCG region.

The gas supply results of the Cost Minimal scenario show that by 2030, each country is producing at their maximum biomethane potential, and it will continue till 2050. From 2030 to 2040, region’s existing and planned LNG terminals will be the source of this remaining NG demand-supply. From 2040, the scenario is achieving carbon neutrality as the supply gets 100% decarbonised by the integration of renewable gases.

## Renewable electricity requirement

Renewable electricity availability is vital for renewable hydrogen and SNG production in all scenarios but especially in the hydrogen scenario, where the final gas demand in each country will be majorly based on renewable hydrogen. Renewable electricity requirements in each scenario by 2030/2040/2050 are presented in Figure 7‑1. By 2050, Estonia, Latvia, and Finland will have the highest renewable electricity requirement in the REN-Hydrogen scenario with 3.2 TWh, 4.7 TWh, and 10.6 TWh, respectively. While Lithuania has the highest renewable electricity requirement in Cost Minimal scenario. (To have a look at country-specific renewable electricity and hydrogen production potential, see the sub-section 5.2 in Deliverable 2 'Baseline data collection' report)

Figure 7‑1. Renewable electricity requirement for hydrogen production by each scenario

Based on the electricity requirements (Figure 7‑1), the following Table ‎7‑4 presents the equivalent size of renewable electricity production facilities in each country (separately for two cases, a) if all of the required renewable electricity is produced from on-shore wind capacities or b) off-shore wind plants capacities). The load factor of off-shore and on-shore wind energy is different for each country in the region, resulting in variable capacity requirement for wind plants.

Table ‎7‑4. Prognosis of required renewable power production capacities in GW

|  |  |  |  |
| --- | --- | --- | --- |
| Country | Scenarios | Off-shore wind plant - 2050 | On-shore wind plant - 2050 |
| **Estonia** | **BAU** | 0.046 | 0.1 |
| **REN-Methane** | 0.113 | 0.2 |
| **REN-Hydrogen** | 0.859 | 1.2 |
| **Cost minimal** | 0.084 | 0.1 |
| **Latvia** | **BAU** | 0.1 | 0.1 |
| **REN-Methane** | 0.5 | 0.6 |
| **REN-Hydrogen** | 1.3 | 1.8 |
| **Cost minimal** | 0.1 | 0.1 |
| **Lithuania** | **BAU** | 2.8 | 4.4 |
| **REN-Methane** | 3.1 | 5.0 |
| **REN-Hydrogen** | 5.4 | 8.7 |
| **Cost minimal** | 2.7 | 4.4 |
| **Finland** | **BAU** | 2.0 | 2.2 |
| **REN-Methane** | 1.5 | 1.6 |
| **REN-Hydrogen** | 3.6 | 3.9 |
| **Cost minimal** | 2.3 | 2.5 |

## Regional LNG terminal capacities

Table ‎7‑2 shows the role of country-specific LNG capacities in each scenario. These results will provide a solution for the region in terms of required LNG capacities for the entire region to get out of the energy crisis (no gas import from Russia). In the BAU scenario, though the required NG demand will decrease over the years, LNG dependency will still be the major case for RGMCG countries (3B+F). The optimisation of required LNG terminal capacities is one of the most significant outcomes of scenario modelling. Overall, under different scenarios, the model deploys 5-6 TWh capacity for Estonia between 2030 and 2050, 11-20 TWh capacity for Finland between 2034 and 2050, and 4-21 TWh capacity for Lithuania after 2044. Based on the expert analysis, these additional new LNG capacities does not need to be deployed. The NG demand is gradually diminishing in all the scenarios for all the countries, allowing the region to utilise the existing Klaipeda LNG terminal capacity till 2044 and the planned LNG capacity of skulte terminal in Latvia till 2050. To balance the NG demand and supply, any country in the region can book their LNG capacities/cargo quantities to the existing/planned terminals in the RGMCG region.

The total available existing/planned LNG capacities and the additional optimised capacities, for each country in each scenario by 2050 is presented in Table ‎7‑5. Upon cross-scenario comparison, for all the scenarios if existing Klaipeda LNG terminal (till 2044) and planned Skulte LNG terminal (till 2050) are in existence, the regional market will have enough capacity flexibility at sub-annual level to balance the region's (3B+F) NG demand. In that case renewing/replacing the Finnish FSRU lease after 2033 will not be required, as regional gas is supposed to be carbon neutral after 2040 or 2050 (based on the scenario). Except for the BAU scenario, all the scenarios will achieve full decarbonisation by 2050. There will be no fossil LNG import by 2050 in the full decarbonised scenarios, but the stranded LNG terminal capacities can be repurposed for any import/export possibility of liquid hydrogen or other hydrogen-based energy carriers (e.g., methanol or ammonia).

Table ‎7‑5. Total regional LNG terminal capacities by 2050

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Country | Existing or planned capacities (TWh) | Existing/Planned available capacities by 2050 | BAU scenario | REN-Methane scenario | REN-Hydrogen scenario | Cost minimal scenario |
| Additional optimised capacities by 2050 in TWh[[48]](#footnote-49) | | | |
| Estonia | 0 | 0 | 6 | 5 | 5 | 0 |
| Latvia | 65 | 65 | 0 | 0 | 0 | 0 |
| Lithuania | 39 | 0 | 21 | 4 | 0 | 0 |
| Finland | 54 | 2 | 18 | 11 | 9 | 0 |
| RGMCG | 158 | 67 | 45 | 19 | 14 | 0 |

## Gas flows

In the BAU scenario, the gas flow volume will decrease slightly by 2050 compared to 2030. This is because the overall gas demand is falling by 2050, and domestic gas production (biomethane and renewable hydrogen) will help to reduce the annual import dependency (Figure ‎3‑4).

In the REN-Methane scenario, the import dependency (LNG or NG import from a country outside RGMCG) of the region will decrease by 2050; at the same time, the gas flow between the countries will increase by 2050 in comparison with 2030. The cross-border flow in 3B+F will increase mainly due to the production profiles[[49]](#footnote-50) of biomethane, renewable hydrogen and SNG production systems. The sub-annual gap between domestic gas production and demand will trigger the gas flow between the countries with a high level of supply to the other countries in need in the region (Figure ‎4‑4). In the REN-Hydrogen scenario, the import dependency (LNG import from a country outside RGMCG) of the region will diminish by 2040, as by 2041, 100% of the pipeline gas is to be constituted on renewable hydrogen (Figure ‎5‑4).

The optimisation results of the cost minimal scenario show contrasting results for 2030 and 2050. In 2030, the gas flow between the countries is minimal due to the availability of the existing/planned LNG terminals in the region. In 2050, Lithuania will be a net importer in the region, as it is importing 2.56 TWh, and has no exports outside the country. This is because of two main reasons, firstly the biomethane potential of Lithuania cannot fully cover the national gas demand and secondly the lifetime of the biomethane capacities (partial capacity around 1 TWh) in Lithuania expired by 2047[[50]](#footnote-51). Based on the least cost optimisation, the model decided to start importing the renewable gas instead of building new biomethane capacities in Lithuania for the next 3 years (Last modelling year is 2050). The excess biomethane production from Finland is exported to Lithuania to satisfy the Lithuanian demand requirement (Figure ‎6‑4). Finland has sufficient biomethane potential to satisfy its own gas demand, as well as capacity to export up to 2-3 TWh of biomethane to the countries within the RGMCG region. If there is a gas requirement in future, it is economically viable for the region to import them from Finland or countries within the region rather import them from outside.

## Storage

Within the model, the underground gas storage in Latvia acts as a common gas storage point for the Baltic Finnish region. The model optimised the storage capacities, levels, and utilisation across all scenarios. The model was constrained in the BAU and the renewable modelled scenarios not to add any new pipeline-connected gas storage capacity. The model was also allowed to build any required off-network gas storage capacity.

It is analysed that in BAU and REN-Hydrogen scenarios, there will be no utilisation of Latvian UGS for regional demand over the next decades. In REN-Methane, there will be no utilisation in 2030 and 2040, but there will be utilisation in 2050 up to 4TWh. The reason of non-utilisation of UGS in 2030 and 2040 is because of region’s substantial available LNG terminal capacities (Finnish FSRU, Skulte LNG terminal in Latvia, and Klaipeda LNG terminal in Lithuania). Cost minimal scenario presents the highest utilisation of UGS by 2040 and 2050 (total injection/withdrawal as 4.7/4.3 TWh in 2040 and total injection/withdrawal as 3.4/3.3 TWh in 2050).

Technical limitations of the UGS are considered to store the blended gas in Latvian UGS. Biomethane and SNG can technically be stored without significant changes in the UGS. However, the feasibility of storing blended hydrogen gas or pure hydrogen is subject to further technical investigations, which are expected to be completed in the coming years (information shared by Conexus Baltic Grid, the Latvian gas TSO and UGS operator).

The optimisation results indicate that there is no off-network storage requirement for biomethane, but it does show the storage requirements for off-network renewable hydrogen. Figure ‎7‑2depicts the hydrogen storage capacities for each country in each scenario. Comparatively, Lithuania and Finland require high standalone hydrogen storage capacities in the region due to the high demand for pure hydrogen for the industries. The storage capacity requirements remain the same across 2030, 2040, and 2050.

Figure ‎7‑2 Hydrogen storage capacities for off-network hydrogen by each scenario

## Levelised costs of production

Table ‎7‑3 shows the levelised cost of energy (LCOE) for the renewable gases competing against natural gas for each country in all the scenarios (**see section ‘Levelised costs of production of the renewable gases’ for the levelised cost calculation methodology**). The levelised renewable gas cost is calculated based on the discounted CAPEX, discounted OPEX, discounted VOM, and total energy production. The results showed that, biomethane would be the cheapest produced gas compared to other gases by 2050. The average cost (across scenarios) of biomethane production for 2050 is calculated as, 63 EUR/MWh in Estonia, 44 EUR/MWh in Latvia, 57 EUR/MWh in Lithuania, and 54 EUR/MWh in Finland. Latvia has the lowest levelised production costs for biomethane in the region as biowaste is the only feedstock allocated and has no feedstock cost associated with it.

In all four countries, the production cost of renewable hydrogen declined more than two times in 2050 compared with 2030's LCOE. This is due to the learning curves of technology; efficiency increase and total produced gas volumes. By 2050, the average production cost (across scenarios) of renewable hydrogen is calculated to be 103 EUR/MWh in Estonia, 107 EUR/MWh in Latvia, 101 EUR/MWh in Lithuania and 108 EUR/MWh in Finland. (**see the section 3.9 for the explanation on the Levelised costs being different for the same fuel in different countries**). The modelled scenarios REN-Methane, and REN-Hydrogen, will be decarbonised by 2050 with domestic renewable gas production in each country. These scenarios will give a long-term solution for the Baltic Finnish region, such as how the region can utilise their own renewable gas potential and be independent in terms of gas import outside the RGMCG region. The cost-minimal scenario illustrates a short-term solution for the decarbonisation of the region since, using the least cost optimisation method, the scenario deploys all of its available biomethane capacity by 2030, resulting in quick gas market decarbonisation for the region.

Table ‎7‑6 NG import volumes (as LNG) and net generation of domestic renewable gases (TWh) for 2030 and 2050

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Scenario** | **Country** | **Gas supply (TWh by 2030)** | | | | | | **Gas supply (TWh by 2050)** | | | | | |
| ***NG (imported as LNG)*** | ***Biomethane*** | ***Hydrogen*** | ***SNG*** | ***Biogas*** | ***Total*** | ***NG (imported as LNG)*** | ***Biomethane*** | ***Hydrogen*** | ***SNG*** | ***Biogas*** | ***Total*** |
| **BAU** | Estonia | 4.13 | 0.34 | 0.08 | 0 | 0.10 | 4.65 | 2.90 | 0.75 | 0.12 | 0 | 0.10 | 3.87 |
| Latvia | 9.13 | 0.25 | 0.18 | 0 | 0.47 | 10.03 | 4.67 | 0.53 | 0.21 | 0 | 0.47 | 5.88 |
| Lithuania | 18.96 | 1 | 2.73 | 0 | 0.39 | 23.08 | 12.45 | 3.23 | 8.05 | 0 | 0.39 | 24.12 |
| Finland | 17.35 | 3.18 | 1.63 | 0 | 0.87 | 23.03 | 7.31 | 6.63 | 4.47 | 0 | 0.87 | 19.28 |
| **RGMCG region** | **49.57** | **4.78** | **4.62** | **0** | **1.83** | **60.8** | **27.33** | **11.14** | **12.86** | **0** | **1.83** | **53.16** |
| **REN-Methane** | Estonia | 2.59 | 0.80 | 0.12 | 0.29 | 0.10 | 3.9 | 0 | 2.40 | 0.14 | 0.13 | 0.10 | 2.77 |
| Latvia | 6.64 | 2.20 | 0.32 | 0.29 | 0.47 | 9.92 | 0 | 2.78 | 0.24 | 0.82 | 0.47 | 4.31 |
| Lithuania | 13.17 | 2.71 | 2.94 | 0.60 | 0.39 | 19.81 | 0 | 8 | 8.09 | 0.77 | 0.39 | 17.25 |
| Finland | 12.98 | 3.66 | 1.94 | 0 | 0.87 | 19.45 | 0 | 9.41 | 3.20 | 0 | 0.87 | 13.48 |
| **RGMCG region** | **35.37** | **9.38** | **5.33** | **1.18** | **1.83** | **53.09** | **0** | **22.59** | **11.68** | **1.72** | **1.83** | **37.8** |
| **REN-Hydrogen** | Estonia | 3.22 | 0.34 | 0.23 | 0 | 0.10 | 3.89 | 0 | 0.39 | 2.34 | 0 | 0.10 | 2.83 |
| Latvia | 7.47 | 0.25 | 0.40 | 0 | 0.47 | 8.59 | 0 | 0.39 | 3.50 | 0 | 0.47 | 4.36 |
| Lithuania | 15.40 | 1 | 2.93 | 0 | 0.39 | 19.72 | 0 | 2.12 | 15.86 | 0 | 0.39 | 18.37 |
| Finland | 12.60 | 3.24 | 3.37 | 0 | 0.87 | 20.08 | 0 | 3.50 | 7.87 | 0 | 0.87 | 12.24 |
| **RGMCG region** | **38.69** | **4.83** | **6.93** | **0** | **1.83** | **52.2** | **0** | **6.4** | **29.57** | **0** | **1.83** | **37.8** |
| **Cost minimal** | Estonia | 0 | 2.40 | 0.14 | 0 | 0.10 | 2.64 | 0 | 2.40 | 0.23 | 0 | 0.10 | 2.73 |
| Latvia | 7.01 | 2.70 | 0.40 | 0 | 0.47 | 10.58 | 0 | 2.70 | 0.28 | 0 | 0.47 | 3.45 |
| Lithuania | 5.32 | 8 | 3 | 3.3 | 0.39 | 20.01 | 0 | 6.32 | 7.95 | 0 | 0.39 | 14.66 |
| Finland | 4.20 | 11 | 2.88 | 0 | 0.87 | 18.95 | 0 | 11 | 5.06 | 0 | 0.87 | 16.93 |
| **RGMCG region** | **16.53** | **24.1** | **6.42** | **3.3** | **1.83** | **52.18** | **0** | **22.42** | **13.52** | **0** | **1.83** | **37.8** |

Table ‎7‑7 Installed capacity of renewable gas production systems for 2030 and 2050

|  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Scenario** | **Country** | **Renewable gas production systems (MW by 2030)** | | | | **Renewable gas production systems (MW by 2050)** | | | |
| ***Biomethane*** | ***Hydrogen*** | ***SNG*** | ***Biogas*** | ***Biomethane*** | ***Hydrogen*** | ***SNG*** | ***Biogas*** |
| **BAU** | Estonia | 81 | 30 | 0 | 13 | 136 | 77 | 0 | 13 |
| Latvia | 34 | 73 | 0 | 62 | 71 | 138 | 0 | 62 |
| Lithuania | 135 | 1184 | 0 | 52 | 441 | 3649 | 0 | 52 |
| Finland | 447 | 764 | 0 | 118 | 910 | 2281 | 0 | 118 |
| **RGMCG region (total)** | **697** | **2051** | **0** | **245** | **1558** | **6145** | **0** | **245** |
| **REN Methane** | Estonia | 143 | 44 | 89 | 13 | 357 | 90 | 89 | 13 |
| Latvia | 314 | 117 | 91 | 62 | 407 | 182 | 310 | 62 |
| Lithuania | 364 | 1250 | 185 | 52 | 1074 | 3715 | 239 | 52 |
| Finland | 512 | 874 | 0 | 118 | 1283 | 1632 | 0 | 118 |
| **RGMCG region (total)** | **1333** | **2284** | **365** | **245** | **3121** | **5619** | **638** | **245** |
| **REN Hydrogen** | Estonia | 81 | 120 | 0 | 13 | 109 | 1923 | 0 | 13 |
| Latvia | 34 | 165 | 0 | 62 | 52 | 1209 | 0 | 62 |
| Lithuania | 135 | 1246 | 0 | 52 | 284 | 7348 | 0 | 52 |
| Finland | 454 | 1605 | 0 | 118 | 598 | 3432 | 0 | 118 |
| **RGMCG region (total)** | **704** | **3136** | **0** | **245** | **1043** | **13912** | **0** | **245** |
| **Cost minimal** | Estonia | 357 | 72 | 0 | 13 | 357 | 200 | 0 | 13 |
| Latvia | 363 | 159 | 0 | 62 | 363 | 299 | 0 | 62 |
| Lithuania | 1074 | 1310 | 1030 | 52 | 1074 | 3820 | 1030 | 52 |
| Finland | 1497 | 1360 | 0 | 118 | 1497 | 2736 | 0 | 118 |
| **RGMCG region (total)** | **3291** | **2901** | **1030** | **245** | **3291** | **7055** | **1030** | **245** |

Table ‎7‑8 Cost of renewable gas production systems for 2030 and 2050 (CAPEX for the existing off-Network biogas capacities is not considered)

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Scenario** | **Country** | **Cost of renewable gas production systems (Million Euros) -2030** | | | | | | | **Cost of renewable gas production systems (Million Euros) -2050** | | | | | | | |
| ***Biomethane*** | | ***Hydrogen*** | | ***SNG*** | | ***Biogas*** | ***Biomethane*** | | ***Hydrogen*** | | ***SNG*** | | ***Biogas*** |
| ***CAPEX*** | ***OPEX*** *(fixed + variable)* | ***CAPEX*** | ***OPEX*** *(fixed + variable)* | ***CAPEX*** | ***OPEX*** *(fixed + variable)* | ***OPEX (fixed + variable)*** | ***CAPEX*** | ***OPEX*** *(fixed + variable)* | ***CAPEX*** | ***OPEX*** *(fixed + variable)* | ***CAPEX*** | ***OPEX*** *(fixed + variable)* | ***OPEX*** *(fixed + variable)* |
| **BAU** | Estonia | 99.3 | 114.4 | 26.5 | 10.8 | 0 | 0 | 36.34 | 167.5 | 651.9 | 53.5 | 135 | 0 | 0 | 117.11 |
| Latvia | 41.2 | 41.6 | 71.1 | 29 | 0 | 0 | 207.4 | 87.1 | 311.3 | 108.7 | 282.7 | 0 | 0 | 668.31 |
| Lithuania | 166.2 | 237.1 | 1707 | 1066.9 | 0 | 0 | 115.95 | 544.2 | 2417.7 | 3128 | 7760.7 | 0 | 0 | 373.62 |
| Finland | 553.2 | 712.2 | 1079 | 613.7 | 0 | 0 | 121.87 | 1125.2 | 4964.5 | 1949 | 4404.8 | 0 | 0 | 392.7 |
| **RGMCG region (total)** | **859.8** | **1110.3** | **2880** | **1720.4** | **0** | **0** | **481.56** | **1924** | **8345.4** | **5239** | **12583** | **0** | **0** | **1551.74** |
| **REN Methane** | Estonia | 175.8 | 219.5 | 35.6 | 14.1 | 132.4 | 30.1 | 36.34 | 439.6 | 1855.6 | 62.5 | 179.2 | 170.3 | 389.2 | 117.11 |
| Latvia | 386.1 | 538.3 | 99.9 | 39.5 | 134.6 | 30.1 | 207.4 | 499.3 | 2305.7 | 137.5 | 379.6 | 557.3 | 1439.2 | 668.31 |
| Lithuania | 449.4 | 640.9 | 1750 | 1083.3 | 274.4 | 63.1 | 115.95 | 1325.5 | 6216.2 | 3171 | 7922 | 425.3 | 1045.1 | 373.62 |
| Finland | 568.3 | 789.4 | 956.7 | 637.7 | 0 | 0 | 121.87 | 1518.9 | 6013.1 | 1612 | 4295.9 | 0 | 0 | 392.7 |
| **RGMCG region (total)** | **1579.5** | **2188.1** | **2842** | **1774.7** | **696.4** | **123.3** | **481.56** | **3783** | **16391** | **4983** | **12777** | **1153** | **2873.5** | **1551.74** |
| **REN Hydrogen** | Estonia | 99.3 | 114.4 | 145.5 | 114.4 | 0 | 0 | 36.34 | 239.4 | 500.4 | 1124 | 5744.5 | 0 | 0 | 117.11 |
| Latvia | 41.2 | 41.6 | 180.1 | 161.2 | 0 | 0 | 207.4 | 166.9 | 230.8 | 674.2 | 4312.8 | 0 | 0 | 668.31 |
| Lithuania | 166.2 | 237.1 | 1754 | 1994.8 | 0 | 0 | 115.95 | 912.2 | 1637.5 | 4560 | 25449.6 | 0 | 0 | 373.62 |
| Finland | 560.9 | 713 | 2293 | 2398.8 | 0 | 0 | 121.87 | 1814.2 | 3277.3 | 3210 | 15692.1 | 0 | 0 | 392.7 |
| **RGMCG region (total)** | **867.6** | **1106.1** | **4357** | **2537.7** | **0** | **0** | **481.56** | **1850** | **5646.1** | **10637** | **27952** | **0** | **0** | **1551.74** |
| **Cost minimal** | Estonia | 439.6 | 1016.3 | 120 | 81.3 | 0 | 0 | 36.34 | 439.6 | 3274.7 | 193.7 | 346.3 | 0 | 0 | 117.11 |
| Latvia | 445.23 | 821.6 | 304.3 | 255.3 | 0 | 0 | 207.4 | 445.23 | 2647.3 | 385 | 658.3 | 0 | 0 | 668.31 |
| Lithuania | 1325.53 | 3492.7 | 2110 | 1499.6 | 1960.6 | 350.7 | 115.95 | 1325.53 | 11108.4 | 3556 | 8409.1 | 1960.6 | 4224.8 | 373.62 |
| Finland | 1851.18 | 4189.8 | 2174 | 1393.4 | 0 | 0 | 121.87 | 1851.18 | 13500.5 | 3018 | 7301.1 | 0 | 0 | 392.7 |
| **RGMCG region (total)** | **4061.6** | **9520.4** | **4708** | **3229.7** | **1961** | **350.7** | **481.56** | **4062** | **30531** | **7153** | **16715** | **1961** | **4224.8** | **1551.74** |

Table ‎7‑9 Levelised production costs of the renewable gases for 2030 and 2050

|  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Scenario** | **Country** | **Levelised costs of the renewable gases vs. NG price 2030 (EUR/MWh)** | | | | | **Levelised costs of the renewable gases vs. NG price 2050 (EUR/MWh)** | | | | |
| **Biomethane** | **Hydrogen** | **SNG** | **NG price with ETS** | **NG price without ETS** | **Biomethane** | **Hydrogen** | **SNG** | **NG price with ETS** | **NG price without ETS** |
| **BAU** | Estonia | 99 | 293 | - | 113 | 91 | 65 | 98 | - | 138 | 96 |
| Latvia | 69 | 301 | - | 113 | 91 | 45 | 102 | - | 138 | 96 |
| Lithuania | 64 | 227 | - | 113 | 91 | 54 | 101 | - | 138 | 96 |
| Finland | 77 | 253 | - | 113 | 91 | 53 | 106 | - | 138 | 96 |
| **RGMCG region (average)** | **77.3** | **268.7** | **-** | **113** | **91** | **54.5** | **101.6** | **-** | **138** | **96** |
| **REN Methane** | Estonia | 91 | 290 | 700 | 113 | 91 | 60 | 95 | 156 | 138 | 96 |
| Latvia | 52 | 297 | 711 | 113 | 91 | 41 | 102 | 128 | 138 | 96 |
| Lithuania | 67 | 238 | 692 | 113 | 91 | 54 | 101 | 138 | 138 | 96 |
| Finland | 75 | 232 | - | 113 | 91 | 54 | 106 | - | 138 | 96 |
| **RGMCG region (average)** | **71.2** | **264.2** | **701** | **113** | **91** | **52.4** | **101** | **140.3** | **138** | **96** |
| **REN Hydrogen** | Estonia | 99 | 302 | - | 113 | 91 | 68 | 95 | - | 138 | 96 |
| Latvia | 69 | 270 | - | 113 | 91 | 46 | 86 | - | 138 | 96 |
| Lithuania | 84 | 238 | - | 113 | 91 | 59 | 95 | - | 138 | 96 |
| Finland | 78 | 253 | - | 113 | 91 | 56 | 107 | - | 138 | 96 |
| **RGMCG region (average)** | **82.3** | **265.7** | **-** | **113** | **91** | **57.3** | **95.8** | **-** | **138** | **96** |
| **Cost minimal** | Estonia | 70 | 230 | - | 113 | 91 | 57 | 125 | - | 138 | 96 |
| Latvia | 55 | 206 | - | 113 | 91 | 43 | 139 | - | 138 | 96 |
| Lithuania | 70 | 222 | 692 | 113 | 91 | 58 | 108 | 153 | 138 | 96 |
| Finland | 64 | 238 | - | 113 | 91 | 52 | 113 | - | 138 | 96 |
| **RGMCG region (average)** | **64.7** | **224** | **692** | **113** | **91** | **52.6** | **121.3** | **153** | **138** | **96** |

# Answers to the additional study questions

## Impacts of hydrogen blending on NG infrastructure

Blending hydrogen into existing natural gas pipelines can be done for environmental reasons (to reduce the carbon intensity of the fossil methane). As a part of the hydrogen strategy, the EU commission under REPowerEU is focusing on integrating renewable hydrogen into the gas sector to reduce the dependency on Russian natural gas. According to the EU Commission, any new required gas infrastructure must be compatible with hydrogen. In general, there are three options for transferring hydrogen through gas pipelines:

* Retrofitting (e.g., blending of hydrogen with natural gas) - It is an improvement to the current infrastructure that permits the injection of a limited amount of hydrogen into a natural gas stream up to a technically sound threshold of H2/CH4 combination (i.e., blending).
* Repurposing - It is transforming a natural gas pipeline that already exists into a dedicated hydrogen pipeline.
* Construction of new dedicated hydrogen infrastructure - Hydrogen has an energy density three times lower than methane. Around 3.6 kWh/Nm3 or 12.8 MJ/Nm3 for hydrogen, compared to 11.8 kWh/Nm3 or 42.3 MJ/Nm3 for natural gas. Therefore, the volume of hydrogen transported must be about three times greater than that for natural gas to meet the same energy demand. The pressure of the pipes is limited by design; the variable parameter will therefore be the flow speed, which is three times higher with hydrogen than with natural gas. However, with a network made up entirely of 100% hydrogen, the compression energy will be roughly three times higher for transport at an equivalent pressure drop31.

Blending hydrogen into an existing gas network network has various limitations, e.g., complexity of managing the blend mixture, technical challenges, including the effect on pipeline material and other system components, as well as adaptation of valves, compressors, and metering instruments.

The main advantages of repurposing the existing NG pipelines include the cost-benefit compared to deploying new dedicated hydrogen pipelines and the regulatory and social aspects because the existing infrastructure is already built and socially approved (routes, including rights of way and use). Additionally, the existing NG network, which has considerable geographic coverage throughout the region, can be gradually converted to operate on blended hydrogen, depending on developments in the supply and demand of the fuel. The technology to achieve this is already widely accessible and has been proven. Another technical issue that may merit further research is handling residual sulphur used to odorise natural gas and other residues that remain in the NG network but can't be entirely removed when the gas is converted into pure hydrogen. This is because some hydrogen applications require extremely pure hydrogen. There is no one-size-fits-all approach to converting NG pipelines to hydrogen; each situation calls for a thorough and supported engineering examination.[[51]](#footnote-52)

### Common gas quality standards (hydrogen blending levels) among the region

The maximum permitted hydrogen concentration in natural gas networks mostly depends on pressure, structure, and existing infrastructure changes. However, based on literature and inputs from the gas transmission system operators, it is suggested that, for grid segments, specific blending percentages (for example, 2% to 10% in volumetric terms) are theoretically possible without any major investment. With infrastructural changes such as retrofitting compressors, coating of pipelines and others, some operators believe 20% to be the top bound even though further tests are required, especially given the demands placed on downstream users to adapt beyond these points[[52]](#footnote-53),[[53]](#footnote-54).

Figure ‎8‑1 Technical constraints of hydrogen blending in gas pipeline

Bubble chart

Description automatically generated with low confidence

Hence, for the modelling exercise, it was decided to implement the base assumption of a maximum of 10 vol.% hydrogen blending level. The decision was based on the added value of blending against the investments required for the retrofitting (blending levels higher than 10 vol.% will require significant investment costs; even then, maximum blending levels of 30-40 vol.% can only be achieved). In future, if these blending levels are to be implemented, TSOs in the joint gas market (3 Baltic States + Finland) must make sure that the blend levels while gas trading will be within the expected standards. Another critical point while considering the hydrogen blending infrastructure deployment is the location of the hydrogen injection, which must be carefully planned by TSOs while considering the future gas flow directions to achieve homogenised gas blends within the region.

## Impacts of hydrogen blending on end-use equipment

There is no one-size-fits-all approach regarding the hydrogen blending impacts on the end-use equipment. Blending levels of more than ten vol.% will impose more retrofitting implications on the user applications. Many appliances will have to be replaced if higher hydrogen blends are desired to be implemented. In a hydrogen-based gas economy, in addition to the gas infrastructure upgradation investments, replacing end-use equipment will also impose enormous investment costs.

MARCOGAZ is the technical association of the European gas industry. Its responsibility includes monitoring and policy advisory activities related to European technical regulation, standardisation, and certification concerning the safety and integrity of gas systems and equipment, rational use of energy, and environment and health. Technical activities of MARCOGAZ include transmission, distribution and storage systems and end use of gas (natural gas, hydrogen, biomethane, synthetic gases) in their gaseous or liquid forms (e.g., LNG). Table ‎8‑1 presents Marcogaz’s test results and regulatory limits for hydrogen admixture into end-use equipment across different sectors.

Table ‎8‑1. Overview of available test results and regulatory limits for hydrogen admixture into end-use equipment [Source: Marcogaz][[54]](#footnote-55)

|  |  |  |
| --- | --- | --- |
| Sector | End-use equipment | Hydrogen blending levels |
| Power | Gas turbine | Up to 1% without modifications |
| Gas engine | Up to 10-15% without modifications |
| Gas compressor | Up to 10% |
| Residential appliances | Gas fuelled heating appliances | Up to 10% |
| Gas cooker/burner | Up to 10% |
| Condensing boiler | Up to 10% |
| Mobility | CNG vehicle | Up to 5% |
| Industrial equipment | Feedstock | Up to 2% with some use case base modifications |
| Steam boiler | Up to 5% without modifications |
| Industrial thermal processes (uncontrolled) | Up to 5% without modifications |

Marcogaz concludes that residential appliances can work properly up to 10 vol.% hydrogen blend levels. In contrast, CNG vehicles can only allow a maximum of five vol.% without replacing the CNG tank and critical engine parts. Industrial equipment can also work with a maximum of 5 vol.% of hydrogen blends without requiring substantial retrofitting. There are some industrial uses of NG, where NG is used as a feedstock, e.g., refinery processes or fertiliser industry, where the gas purity fluctuations (more than two vol.% blends) can disrupt the other series of processes while impacting the reactor kinetics. These industries will require gas cleaning (pre-processing) of incoming gas at the industry gate.

## Cost analysis of repurposing of NG gas networks

Various studies examine the economics of repurposing, mainly regarding investment expenditures and forecasting the costs of transporting pure hydrogen based on multiple scenarios' assumptions. According to the research, it is feasible to convert long-distance gas networks from NG to hydrogen with little financial effort. It is projected that the cost of repurposing the lines will be between 10% and 15% of the price of building new hydrogen lines. This cost will include decommissioning from NG operation, water pressure checks, replacement of fittings, and removal of connections, among other things. Given the facts, building a 100% dedicated hydrogen pipeline would be more expensive than an NG network. It can be estimated that the Capex for a new pure hydrogen pipeline is between 110 and 150 % of what it would be for a new natural gas pipeline of comparable diameter. The cost of replacing a valve also depends on how far apart the valves are from one another. Costs will rise if valves need to be replaced every 15 kilometres.[[55]](#footnote-56)

For a dedicated hydrogen pipeline to enable an energy flow of hydrogen equivalent to 80-90% of the flow of NG, approximately three times the compression power would be required for hydrogen compared to the power necessary for NG and since the energy density of hydrogen is 3 times lesser than methane, other approach for building the dedicated pipelines would be to increase the diameter. The transition of compressor stations to hydrogen still faces difficulties. Some reciprocating compressors have been "tried and tested" for pure hydrogen, but they are typically not a practical solution for big-diameter pipelines. On the other hand, gas turbo-compressors (TC) cannot currently be retrofitted to handle gas that has more than 40% hydrogen by volume. According to studies, conventional compressors powered by gas turbine engines could be modified to run entirely on hydrogen by 2030. To make that possible, new impeller materials that can bear solid centrifugal forces and are resistant to hydrogen are required. For electric-driven compressors, just the compressors must be changed; the engines don't need to be significantly altered.

The recent European Hydrogen Backbone (EHB) report 2022 presents the most updated financial estimates of repurposing NG infrastructure(Table 8‑2).

Table 8‑2 Cost for repurposing/dedicated pipeline infrastructure [EHB 2022] [[56]](#footnote-57)

| **New H2/ repurposed pipeline** | **Cost parameter (Pipeline, diameter)** | **Unit** | **Low** | **Average** | **High** |
| --- | --- | --- | --- | --- | --- |
| New | Small < 28 inch | M€/km | 1.4 | 1.5 | 1.8 |
| Medium 28-37 inch | 2 | 2.2 | 2.7 |
| Large > 37 inch | 2.5 | 2.8 | 3.4 |
| Repurposed | Small < 28 inch | M€/km | 0.2 | 0.3 | 0.5 |
| Medium 28-37 inch | 0.2 | 0.4 | 0.5 |
| Large > 37 inch | 0.3 | 0.5 | 0.6 |
| Operational and maintenance cost | | €/year as a % of Capex | 0.8 | 0.9 | 1.0 |
| Compressor station | | M€/MWe | 2.2 | 3.4 | 6.7 |

Table ‎8‑2 presents the cost comparison between repurposing NG pipelines vs deploying dedicated hydrogen pipelines, and based on these costs estimates, Table ‎8‑3 shows a rough estimate of the investment extent for repurposing the NG pipeline infrastructure in the regional gas market and compares this evaluation with the size of investment volumes required for NG pipelines replacement with dedicated hydrogen pipelines. The calculations are based on pipeline investment data from EHB 202252 report, and the pipeline lengths (TSO and DSO) and approximate diameters data are used from various studies (see Annex B).

The costs represented in the following table indicate the investment extent of repurposing or replacing the total current NG pipelines with dedicated hydrogen pipelines. These numbers do not necessarily present the required investments per country, as the exact line length replacement and repurposing are to be estimated by the respective government TSOs and DSOs. For instance: According to the EHB 202252 report’s vision for future EU hydrogen pipeline infrastructure, around 69% of the existing gas pipelines will be repurposed, and 31% of the current length will be newly deployed.

Table 8‑3 Indicative cost analysis for Baltic-Finnish gas pipeline [EHB 202259, and multiple other sources, see Annex B]

| **Country** | **Pipeline type** | **Pipeline diameter[[57]](#footnote-58)** | **Length (km)** | **Cost of repurposing in M€** | | | **Cost of new H2pipelines in M€** | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
| **Low** | **Average** | **High** | **Low** | **Average** | **High** |
| Latvia | TSO | Medium | 577 | 115.4 | 230.8 | 288.5 | 1154 | 1269.4 | 1557.9 |
| Small | 613 | 122.6 | 183.9 | 306.5 | 858.2 | 919.5 | 1103.4 |
| DSO | Small | 4950 | 990 | 1485 | 2475 | 6930 | 7425 | 8910 |
| Lithuania | TSO[[58]](#footnote-59) | Medium | 1713 | 342.6 | 685.2 | 3426 | 3768.6 | 4625.1 | 3426 |
| Large | 572 | 171.6 | 286 | 1430 | 1601.6 | 1944.8 | 1430 |
| DSO | Small | 8300 | 1660 | 2490 | 11620 | 12450 | 14940 | 11620 |
| Finland | TSO | Medium | 650 | 130 | 260 | 325 | 1300 | 1430 | 1755 |
|  | Small | 650 | 130 | 195 | 325 | 910 | 975 | 1170 |
| DSO | Small | 3100 | 620 | 930 | 1550 | 4340 | 4650 | 5580 |
| Estonia | TSO | Medium | 245 | 49 | 98 | 122.5 | 490 | 539 | 661.5 |
|  | Small | 732.4 | 146.48 | 219.72 | 366.2 | 1025.36 | 1098.6 | 1318.32 |
| DSO | Small | 1486 | 297.2 | 445.8 | 743 | 2080.4 | 2229 | 2674.8 |

## Repurposing opportunities for unused LNG terminals

Due to the recent Russian invasion of Ukraine, the Baltic states and Finland stopped importing Russian/Belarusian natural gas. The model optimised that the region needs additional LNG capacities in the medium to long term to replace the imported Russian/Belarusian gas. The modelling results indicate that after 2040, there will be unused LNG terminals, and after 2050 (in addition to the new capacities), some non-operational LNG terminal capacities will be available due to the fossil LNG phase-out in the region. These capacities can be repurposed for the different hydrogen energy carriers.

Repurposing LNG terminals for hydrogen carriers depends uniquely on each carrier and its characteristics, which differ from LNG. All LNG terminals, present and future, can already import synthetic methane and bio-LNG without the requirement for conversion. But for the hydrogen derivatives like green methanol or green ammonia, repurposing efforts are required. Apart from technical measures, additional measures safety measures and permits are required as these chemicals are different than LNG in nature e.g., ammonia is toxic and the safety zones, therefore environmental permits and safety zones are necessary to be reassessed.

**LNG terminal à Green ammonia terminal, repurposing efforts example**

The volumetric energy density of liquid ammonia is 55% of the volumetric energy density of LNG. Due to the differing densities of LNG and ammonia, LNG terminals used to handle ammonia will have a decreased functional capacity of the storage tank. Equipment with different steel grades and welding characteristics must be utilised to prevent embrittlement. To avoid ineffective Boil-off Gas (BOG) compressor operation, the Boil-off Gas (BOG) system needs to be thoroughly assessed to determine the right compressor configuration. For ammonia service, the piping system needs to be enforced. To guarantee that they work with ammonia and to decide which parts need to be changed, the instrumentation and measuring tools must be thoroughly examined.[[59]](#footnote-60)

It is challenging to estimate the repurposing cost for converting an existing LNG to import different hydrogen carriers as the cost of converting an LNG import terminal to meet hydrogen carrier's (liquid hydrogen, methanol, ammonia) requirements includes engineering, equipment, materials, and civil works to dismantle and remove items and install new materials and equipment. Such estimates can only be made after an in-depth design case study of the LNG terminal and, at the moment, only a few case studies.

Black and Veatch recently investigated the engineering cost estimate to convert an LNG terminal to an Ammonia import terminal. It is estimated that the costs of correcting an LNG terminal to be "ammonia ready" are roughly anticipated to be 11-20% of its CAPEX. **It is expressed that ammonia readiness can be more easily built into newly constructed LNG import facilities**. **Accordingly, the CAPEX increase for newly constructed ammonia-ready terminals ranges from 6.5 to 11.5%**. In the latter situation, the pre-investment planning necessary for ammonia-ready terminals accounts for the CAPEX rise from initial LNG terminal investments. The absolute amount of the CAPEX increase in the latter scenario is higher than that of repurposing already existing terminals because it represents a new expenditure. **The repurposing cost breakdown for the LNG terminals to ammonia-ready LNG import terminals is presented in Table ‎**8‑4.

Table 8‑4 CAPEX breakdown of repurposing the LNG terminals into ammonia-ready LNG import terminals [Black & Veatch][[60]](#footnote-61)

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **Modified or Replaced Components** | **Converting Existing LNG Import Terminals to Ammonia-Ready LNG Import Terminals** | | | **Newly built Ammonia-Ready LNG Import Terminals** | |
| **Impacted Systems LNG Import** | **Component CAPEX of Terminal CAPEX (%)** | **Modification Cost Impact on each component (%)** | **Total CAPEX Increase (%)** | **Component CAPEX of Terminal CAPEX (%)** | **Total CAPEX Increase (%)** |
| Storage tank | 45-50 | 3 | 1-1.5 | 45-50 | 2-2.5 |
| BOG system | 10-15 | 5-8 | 5-8 | 10-15 | 3-6 |
| Pumps | 3-5 | 1-3 | 1-3 | 3-5 | 0 |
| Piping | 5-10 | 40 | 2-4 | 5-10 | 0.5-1 |
| Instrument and control system | 3-5 | 70 | 2-3.5 | 2-4 | 1-2 |
| **Total** | **11.0 – 20.0** | | | **6.5 – 11.5** | |

## Hydrogen transport methods: a comparative cost analysis

The modelling exercise comprises pipeline gas (NG, biomethane, renewable hydrogen, and SNG) and off-network gases (biomethane and renewable hydrogen). Pipeline gas transport within the region is simulated and optimised in the model, but the off-network gas is not supposed to be transported within the country. This section aims to explain the most cost-competitive ways to transport off-network gases. Since biomethane will be produced in a distributed sense as per the feedstock availability, pressurized truck transport to the point of consumption will be most prevalent for off-network biomethane.

But off-network hydrogen transport options need a comprehensive analysis. In addition to being converted into various hydrogen carriers like ammonia or LOHC, hydrogen can be transported in its pure form as a compressed gas or liquid cryogenic form. The most economical method of transporting hydrogen would rely on several parameters, just as for transporting natural gas and other gases. According to the distance and amount of the gas being transported, there are three key "tipping points" to consider when determining the most economical method of transporting pure hydrogen.[[61]](#footnote-62). The following Figure ‎8‑2 depicts the costs of hydrogen transport in different modes of transportation such as compressed gas trucks, liquified gas trucks, ammonia ships, pipelines etc.

Figure ‎8‑2 Cost analysis of hydrogen transportation

Table

Description automatically generated

Truck transportation of hydrogen appears to be the most cost-effective solution for smaller volumes and shorter distances (less than 10 tonnes of hydrogen per day and less than 200 km), in compressed form for short trips and liquid form for small amounts over longer distances (hundreds of km). Pipelines are typically the least expensive option for transporting volumes greater than 10 tonnes per day; distribution pipelines are preferred for local networks. Transmission pipelines with a capacity greater than 100 tonnes per day are better suited to transport large volumes over long distances. Ammonia seems to be more cost-effective for transporting hydrogen carriers over long intercontinental distances (>100 t/day)[[62]](#footnote-63).

## Potential CO2 sources for SNG production

Multiple sources can be considered for CO2 capture depending upon the availability of the industrial sector within a country (e.g., cement, power production, iron and steel, power generation, fossil hydrogen production (SMR), ammonia production, etc.). In addition to the different industrial carbon capture options, direct air capture (DAC) is a potential technology that captures CO2 directly from the air.

CO2 is an integral source of SNG production, and the CO2 capture costs can affect the levelised cost of the produced SNG. The additional cost impact can vary from sector to sector, but DAC is the most expensive technology among all technological options (see Figure ‎8‑3).

During the modelling exercise, the idea of using biomass CHP plants as CO2 sources for SNG production was discussed (per the ToR point for potential CO2 sources for SNG production). Upon more profound analysis of different CO2 capture options, it was found that CO2 sourced from power generation activities can cost between 50-100 EUR/tonCO2, which means, on average, 15 EUR/MWh cost in addition to SNG production costs.

On the other hand, CO2 sourced from biomethane production plants is free of capture costs. Since CO2 is co-produced in biogas upgradation plants, it is considered that the biomethane production plants can supply the required CO2 for SNG production. Consequently, CO2 capture costs can be avoided, as CO2 should be separated to produce biomethane from biogas (CAPEX of biomethane plants includes the CO2 separation unit). Due to the inherent lucrative nature of the combination, CO2 sources from local biogas upgradation plants are selected for SNG production in the modelling.

Employing this integrated approach of utilising the CO2 separated from biogas upgradation for SNG production will stimulate the competitiveness of SNG. It will also encourage local producers to invest in coupled processes (biomethane and SNG plants) to bring out the maximum possible impact of domestic gas production to decarbonise the regional gas market. Figure ‎8‑3 presents the levelised cost of CO2 captured from different sources and compared with the cost additions to the SNG production cost per source.

**Figure ‎8‑3. Levelised cost of CO2 capture by sector**

Source: Adapted from [IEA 2021[[63]](#footnote-64)], USD=EUR

Based on the considered techno-economical biomethane production potential of each country[[64]](#footnote-65) in the region, the maximum total CO2 availability at biomethane plants in Estonia is 242 ktCO2, in Latvia is 283 ktCO2, in Lithuania is 807 ktCO2, and in Finland is 1 110 ktCO2. The calculated maximum CO2 availability at biomethane plants in each country is well above the required CO2 requirements for SNG production.

## Renewable gas export potential outside the Baltic-Finnish region

### Biomethane

The model is supplied with the maximum biomethane production potential per country in the 3B+F region. Country-specific feedstock availability for biomethane production was considered. The considerations are acquired and verified with the responsible authorities in each country (i.e., Biogas associations Energy Ministries or TSOs). Consequently, the country-specific biomethane production constraints per feedstock are entered into the model. A detailed explanation of the maximum biomethane production potential (techno-economically feasible) per country can be found in Deliverable 2, 'Baseline data collection' under sub-section 5.1. A comparison of the utilised biomethane potential per country and the overall national gas demands (for the BAU scenario and the other modelled scenarios) is presented in Table ‎8‑5. It can be seen that more than the domestic biomethane potential would be needed to fulfil the national gas demand in the 3B+F countries, so biomethane export outside the RGMCG region is not feasible.

**Table ‎8‑5. Biomethane export opportunity outside RGMCG**

| Country | Biomethane potential[[65]](#footnote-66) (TWh) | Overall gas demand for 2050 (BAU) | Overall gas demand for 2050 (Modelled scenarios) | Opportunity to export |
| --- | --- | --- | --- | --- |
| Estonia | 2.4 | 3.909 | 2.775 | No |
| Lithuania | 8 | 24.294 | 17.249 | No |
| Latvia | 2.7 | 5.950 | 4.209 | No |
| Finland | 11 | 19.000 | 13.49 | No |

### Renewable hydrogen/SNG

Within the model, hydrogen is considered to be mainly produced by water electrolysis using renewable electricity (mainly on and offshore wind). The renewable electricity potential is relevant for each country's renewable hydrogen production potential. A detailed explanation of the realistic renewable electricity production potential can be found in the Deliverable 2 report 'Baseline data collection' under sub-section 5.2. As a simplified approach, it is assumed that the remaining renewable energy potential after satisfying the country's final electricity demand would be available for renewable hydrogen production. A robust analysis of the renewable hydrogen production potential per country against the overall national gas demands (for the BAU scenario and the other modelled scenarios) and the existing gas infrastructure's role in the future renewable gas export is presented in Table ‎8‑6.

Table ‎8‑6. Renewable hydrogen/SNG export opportunity outside RGMCG

| Country | Renewable hydrogen potential (TWh) | Overall gas demand by 2050 (TWh) | | Opportunity to export as renewable hydrogen or SNG | Existing infrastructure role in export opportunities |
| --- | --- | --- | --- | --- | --- |
| Overall gas demand (BAU) | Overall gas demand (Modelled scenarios) |
| Estonia | 6.24 | 3.909 | 2.775 | Yes | * Renewable hydrogen can also be exported using pan-European hydrogen pipeline infrastructure. * Renewable hydrogen can be exported using the retired LNG terminal capacities as liquid hydrogen or converted to renewable ammonia. However, both options will require repurposing stages of the available LNG terminal capacities (see section ‎8.4). * Renewable hydrogen can also be converted to SNG, which will have the inherent benefit of using the current gas infrastructure (transmission pipelines &LNG terminals) without any additional cost of repurposing. |
| Lithuania | 59.25 | 24.294 | 17.249 | Yes |
| Latvia | 41.6 | 5.950 | 4.209 | Yes |
| Finland | 29 | 19.000 | 13.49 | Yes |

## Relevant R&D and technological developments

Achieving climate neutrality would require us to substantially restrict fossil fuels in the energy sector, replacing them with renewable energy sources and other climate-neutral or low-carbon fuels as much as possible. These sustainable fuels, e.g., renewable hydrogen and synthetic natural gas (SNG), would require immediate R&D steps for fast technological development deployments in the region.

Technology developments in renewable gas production, storage, renewable gas injection/blending, and end-use applications would be required to achieve a carbon-neutral gas sector in the region.

**On the production side**, electrolyser R&D should be a priority, mainly the efficiency increases of electrolysers and the development of noble metal-free electrolysers. The efficiency increase will bring the electricity consumption down, and the noble metal replacements will bring down the CAPEX sharply. For SNG production (in addition to renewable H2), CO2 plays a critical role in the financial viability of the produced gas. CO2 sources based on carbon capture (on different industrial or power generation processes or direct air capture (DAC)) technologies present additional investment requirements, which in turn cause high CO2 costs (see sub-section 8.6). To reduce the SNG costs, using CO2 sourced from biomethane production plants should be tested, resulting in a parallel production system of biomethane and SNG.

**On the gas storage side**, Inčukalns UGS should be tested for different H2/NG blending levels. To evaluate the gas blending impacts on Inčukalns UGS, a study has been commissioned by Conexus Baltic Grid (Latvia TSO and UGS operator), and results are expected[[66]](#footnote-67) in 2023-2024 (as per the recent communications by the Latvian UGS operators, Conexus Baltic grid, the prefeasibility tests are planned for 100% H2 vol. %). Biomethane could be injected in UGS facilities as an exchange gas equivalent to natural gas, provided that the NG standards are met. Biomethane acceptance in the Inčukalns UGS facility should be tested for the oxygen levels implications on the underground storage facility.

Since no feasible seasonal gas storage facilities exist in the region except Inčukalns, new and upcoming gas storage technologies such as Liquid organic hydrogen carriers (LOHC) should be tested as a priority. Different pilots of LOHC technology are already being deployed in Germany and Spain. Pilot deployment and commercialisation of LOHC in the joint gas market countries (3 Baltic States + Finland) would help to add scalable hydrogen storage capacities, especially for large gas consumers like industries.

**On the renewable gas blending/injection side**, biomethane and SNG, if maintained at NG standards, do not pose hydrogen blending-like impacts on the gas network. However, special attention should be given to hydrogen blending to determine the effects of different blend ratios on the gas infrastructure, e.g., filters, gaskets, chromatograms, metering equipment, compressor stations etc. Another critical point is the location of the hydrogen injection, which must be carefully planned by TSOs while considering the future gas flow directions to achieve homogenised gas blends within the region.

**On the end-use gas equipment side**, safe operational testing of household and commercial equipment with different hydrogen blend ratios should be done as a pre-requisite to blended gas supply to the consumers. Also, the de-blend equipment pilots should be deployed for the industries sensitive to NG quality, e.g., fertilisers, refineries etc.

Table ‎8‑7 presents the list of the existing pilot and R&D projects for the renewable gas value chain (production, storage, supply infrastructure, and end-user equipment), which can be an example for future technology deployments.

Table ‎8‑7. List of relevant pilot projects for the renewable gas value chain [ENTSOG H2-Project Visualization tool][[67]](#footnote-68)

| Nr. | Type | Project name | Country | Timeline | Project maturity | Scope and goal | Suitability or applicability in the 3B+F region |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **1** | H2 production | OYSTER | Denmark | 2021-2024 | Project (Pilot) | The OYSTER project will lead to development and demonstration of a marinised electrolyser to integrate with offshore wind turbines. Preparation for further offshore testing of wind-hydrogen systems will be undertaken, and results from the studies will be disseminated in a targeted way to help advance the sector and prepare the market for deployment at scale | Can be taken as a working example for establishing offshore hydrogen production hubs in the 3B+F region |
| **2** | H2 production & consumption | H2 production projects | Italy | 2022-2023 | Project (Pilot) | The companies are studying two pilot projects aiming at supplying green hydrogen to qualified ENI refineries. The two pilot projects will involve electrolysers of around 10 MW each and is expected to start generating green hydrogen by 2022-2023. | This pilot project is an example of renewable hydrogen inclusion in refineries to decarbonise and reduce fossil hydrogen use. This pilot project can be taken as an example to initiate the renewable hydrogen deployment for refineries in Lithuania and Finland. |
| **3** | H2 production & consumption | REFHYNE | Germany | 2018-2022 | Project | The REFHYNE project will install and operate a 10MW electrolyser from ITM Power at a large refinery in Rhineland, Germany, operated by Shell Deutschland Oils. The electrolyser will provide bulk quantities of hydrogen to the refinery's hydrogen pipeline system (currently supplied by two steam methane reformers). The electrolyser will be operated in a highly responsive mode, helping to balance the refinery's internal electricity grid and selling Primary Control Reserve service to the German Transmission System Operators. | This pilot project is an example of renewable hydrogen inclusion in refineries to decarbonise and reduce fossil hydrogen use. This pilot project can be taken as an example to initiate the renewable hydrogen deployment for refineries in Lithuania and Finland. |
| **4** | H2 & SNG Production | P2G Augsburg project | Germany | 2018-NA | Project (Pilot) | Installation of a decentralised power-to-gas system in a residential complex in Augsburg. Renewable electricity is not consumed directly; it is used to generate hydrogen in an electrolyser and converted into synthetic natural gas using carbon dioxide. Synthetic gas, in this way, can be used to create heat in a CHP plant and condensing boiler. | It is a working example of SNG production for the power sector. This can be taken as a reference for SNG to be included in the gas sector mix in the 3B+F region |
| **5** | Integrated project  (H2 & SNG production, UGS H2 storage) | Power to Gas Production with infrastructure building/enhancement | Latvia | NA-NA | Project | Power to Gas technology will be used and generate hydrogen as potentially synthetic hydrocarbon will be injected into the existing gas transmission grid with possible utilisation of existing or new aquifer gas storage. The first step of the demonstration project will be a feasibility study on the best location and technology and the impact of hydrogen on aquifer storage. The option of production of the SNG capturing CO2 from the industrial site also will be considered. | It is an example to initiate the power-to-gas projects (renewable hydrogen and SNG) and test their feasibility for gas blending (in the NG infrastructure) and try hydrogen injection in underground storages points in the 3B+F region |
| **6** | SNG production |  | Poland | NA - 2020 | Project (Pilot) | TAURON Wytwarzanie S.A. built the installation at the Łaziska Power Plant in Poland. After the commissioning, the Institute for Chemical Processing of Coal (IChPW) was responsible for conducting research. | It is an example of initiating the power-to-gas projects (SNG production) in the 3B+F region |
| **7** | Integrated project (Biomethane & SNG production) | Power to Gas WERLTE[[68]](#footnote-69),[[69]](#footnote-70) | Germany | NA - 2013 | Project (Pilot) | The green hydrogen produced is then mixed with CO2 in the mechanisation plant and fed into the natural gas network as synthetic methane. The CO2 required for the process is obtained from the waste gas stream of the neighbouring biomethane plant. The waste heat generated during electrolysis and subsequent methanation is used to meet the heat requirements of this biomethane plant. | This project, since 2013, is a working example of biogasàbiomethane and SNG plant working in a parallel manner, where the waste CO2 from biomethane production is used to produce SNG and can be taken as a best practice example of combining bioenergy and e-gases. |
| **8** | H2 blending | Hydrogen injection into the gas network in Lithuania (power-to-gas) | Lithuania | 2022-2024 | Project (Pilot) | Hydrogen mixing in gas networks, investigating mixture effects in transport infrastructure and consumer devices. | This R&D project example can be taken as a guide to testing the hydrogen blends in NG infrastructure and finding the tolerable H2 mix in the end-use equipment in each country in the Baltic-Finnish zone. |
| **9** | H2 blending | Energy Storage – Hydrogen is injected into the Gas network via an electrolysis field test. | Denmark | 2017-2019 | Project (R&D) | How to implement an H2/NG blend in existing MR stations for transmission and distribution? The project has demonstrated transportation of up to 15% hydrogen in natural gas in a closed-loop high-pressure system consisting of components and infrastructure from both the transmission and distribution grids. The test has shown that there is no increased hydrogen leakage from the system compared to natural gas and that the tested components from the gas system can handle hydrogen in the tested concentrations without significant modifications. | This R&D project example can be taken as a guide to start testing the hydrogen blends in NG infrastructure in the 3B+F zone |
| **10** | H2 de-blending (for sensitive consumers) | FenHYx2 | France | 2021-2025 | Project (R&D) | Optimise separation systems on the network for different use cases. Bench test and demonstrator to de-blend H2/GN to protect sensitive clients and/or to purify H2 (also potentially in case of repurposed pipes) | This is a research project example to show the de-blending of the H2-based blended flows for the sensitive consumers |
| **11** | Adaptation of end consumer application | H2 Ready Central Heating Burner | Netherlands | 2018-2020 | Project (R&D) | Developing a H₂ Burner System as a Retrofit. The goal is to develop a burner system that can replace the current natural gas burner. This means that future boilers for hydrogen can be produced. However, already installed boilers can also be converted with a retrofit. | This project can be taken as an R&D initiative in the 3B+F region to put force into developing local end-use equipment retrofitting technology and skills. |

# Annex A – Detailed scenario description file



# Annex B - Gas pipeline infrastructure of Baltic-Finnish region

**Latvia**

The transmission pipelines are composed of regional gas pipelines intended for Latvian supply and international gas pipelines, which ensure gas transit to neighbouring countries, and their branches. The total length of the transmission pipelines and the transmission pipeline branches is 1 190 km. International gas pipelines have a diameter of (DN)700 with working pressure ranging from 28 to 40 bars, and regional gas pipelines have a diameter between DN100 and DN500 with a working pressure of up to 35 bar, with a design working pressure of up to 55 bar. AS GASO ensures the operation of gas distribution pipelines for the length of 4 950 km, including the network of natural gas pipelines, gas regulation equipment, and electrical protection equipment. The Latvian network also includes one of the most modern natural gas storage facilities in Europe – Inčukalns underground gas storage, which is an important strategic object in the whole Baltic Sea region. It provides the energy security and independence of the whole region. The active gas capacity of the Inčukalns underground gas storage facility can reach up to 2.3 billion cubic meters, which can fully supply the fuel and energy needs of Latvia and the region. [[70]](#footnote-71)

| **National diameters characterising transmission system pipelines in mm lines in mm** | **Length km** |
| --- | --- |
| pipeline diameters DN 700 - Medium | 577 |
| pipeline diameters DN 500 - small | 280 |
| pipeline diameters DN 400 - small | 20 |
| pipeline diameters DN 350 - small | 136 |
| pipeline diameters DN 300 - small | 47 |
| pipeline diameters DN 250 - small | 42 |
| pipeline diameters DN 200 - small | 31 |
| pipeline diameters DN 150 and less - small | 57 |
| **Total**: | **1 190** |

**Lithuania**

The leading gas pipeline network in Lithuania started to be developed in 1961. The most used pipelines have a diameter of 700 mm, with the largest diameter of the pipelines in the Lithuanian network reaching up to 1220 mm. Most of the transmission system has a design pressure of 54 bar[[71]](#footnote-72). Lithuania has a 2 285 km long network of high-pressure gas transmission pipelines operated by amber grid and 8 300 km of distribution network[[72]](#footnote-73) throughout Lithuania. Amber Grid manages two compressor stations with a total capacity of 42.2 MW operating in the network.

**Finland**

The transmission system operated by Gasgrid Finland has approximately 1 300 km of pipeline within Finland. With the distribution grid included, the total length of the gas pipeline grid is around 3 100 km[[73]](#footnote-74). Finland’s high-pressure transmission pipelines are made of steel pipes, most of which are coated with polyethylene plastic. In addition to high-pressure pipelines, the transmission network also features 60 km of low-pressure pipelines. The diameter of the transmission pipelines ranges between DN100 and DN1000. 80% of the pipelines can be inspected internally.

The transmission pipeline network also includes a 77 km offshore steel pipeline from Paldiski, Estonia, to Inkoo, Finland, jointly owned by the Estonian transmission system operator for electricity and gas, Elering. The interconnector pipeline can be operated in both directions. The offshore pipeline’s diameter is DN500, and its design pressure is 80 bar[[74]](#footnote-75). There are three compressor stations (Imatra, Kouvola, and Mäntsäla) in the Finnish network with a total capacity of 64 MW.

**Estonia**

The Estonian transmission network consists of several different pipelines with different pipeline diameters. The total length of transmission pipeline is 977.4 km, and the total length of the distribution line is 1 486 km. The pipelines differ in maximum operating pressure (MOP), diameter, and age. Also, Estonian gas infrastructure has 36 gas distribution stations, three gas-metering stations, two compressor stations and one gas regulation station. [[75]](#footnote-76)

| **National diameters characterizing transmission system pipelines in mm lines in mm** | **Length km** |
| --- | --- |
| Pipeline diameters DN 700 - Medium | 245 |
| Pipeline diameters DN 250 - small | 50.2 |
| Pipeline diameters DN 200 - small | 97.5 |
| Pipeline diameters DN 500 - small | 268 |
| Pipeline diameters DN 400 - small | 45.1 |
| Pipeline diameters DN 300-700 - small | 134.6 |
| **Total**: | 977.4 |

# Annex C - Feedstock mix constraints per country for biomethane production

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  | Estonia | | | |
|  | Agriculture residues | Sewage | Landfill | Biowaste |
| Current off-Network biogas/biomethane production by feedstock | 64% | 4% | 32% | 0% |
| New feedstocks share of on-Network/off-Network biomethane production (2023 onwards till 2050) | 50% | 4% | 0% | 46% |
|  | **Latvia** | | | |
|  | Agriculture residues | Sewage | Landfill | Biowaste |
| Current off-Network biogas/biomethane production by feedstock | 79.2% | 1.3% | 15.1% | 4.4% |
| New feedstocks share of on-Network/off-Network biomethane production (2023 onwards till 2050) | 0% | 0% | 0% | 100% |
|  | **Lithuania** | | | |
|  | Agriculture residues | Sewage | Landfill | Biowaste |
| Current off-Network biogas/biomethane production by feedstock | 39% | 29% | 19% | 13% |
| New feedstocks share of on-Network/off-Network biomethane production (2023 onwards till 2050) | 60% | 10% | 0% | 30% |
|  | **Finland** | | | |
|  | Agriculture residues | Sewage | Landfill | Biowaste |
| Current off-Network biogas/biomethane production by feedstock | 1% | 23% | 49% | 27% |
| New feedstocks share of on-Network/off-Network biomethane production (2023 onwards till 2050) | 40% | 0% | 0% | 45% |

**Sources:** The percentages are made based on the existing and future feedstock mix availability information provided either by the Energy Ministry or by the Biogas association of the relevant country.

# Annex D – Technical assumptions

**1. NG and ETS price projections**

Source: ETS projections data**[[76]](#footnote-77)** adapted from based on from [S&P Global, 2022]**[[77]](#footnote-78)** and [REUTERS, 2022]**[[78]](#footnote-79)**, NG price projections are Author’s NG projections based on historical NG price data from GET Baltic**[[79]](#footnote-80)** and Bloomberg**[[80]](#footnote-81)**

**2. Renewable Electricity price (as an average of Onshore and Offshore wind energy)**

Source: Projection based on the production cost data from IRENA (2022)**[[81]](#footnote-82)** and Lazard (2021)**[[82]](#footnote-83)**

**3. Wind energy load factor (averaged values for onshore and offshore wind energy)**

Source: ENTSO-E (2020). Mid-term Adequacy Forecast 2020 Pan-European Climate Database**[[83]](#footnote-84)**

**4. LNG terminal utilisation curve (based on the sub-annual average utilisation of 2021/2022’s Klaipeda LNG terminal)**

Source: Klaipeda LNG terminal[[84]](#footnote-85)

Background pattern

Description automatically generated with medium confidenceThe project is funded by the European Union via the Technical Support Instrument and is carried out in cooperation with the Directorate General for Structural Reform Support of the European Commission. The project is implemented by Trinomics B.V., in association with SEI and E3Modelling, over 17 months.

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1. Deliverable 3 (scenario modelling) is not aimed at the optimal pipeline design parameters (pipeline lengths and geolocation of injection points of different gases) for future scenarios. [↑](#footnote-ref-2)
2. Regional gas networks, regional gas network interconnections, Inčukalns underground gas storage in Latvia and Klaipeda LNG terminal in Lithuania. [↑](#footnote-ref-3)
3. Hamina LNG terminal, Inkoo FSRU in Finland, and Skulte LNG terminal in Latvia. [↑](#footnote-ref-4)
4. For Estonia, sectoral gas consumption was summed to get the total national consumption, whereas only national-level gas demands have been taken and verified by the respective energy ministries representative of the countries. [↑](#footnote-ref-5)
5. Pipeline Gas includes Natural gas, biomethane, SNG and Green Hydrogen. Based on the scenario and decade, the fuel blend will differ (similar for all the countries). [↑](#footnote-ref-6)
6. Only international pipeline transport is represented in the model. Local distribution pipeline networks are not included explicitly. [↑](#footnote-ref-7)
7. The listed gas consuming sectors in the RGMCG region are buildings, industries, transport, power, heating and agriculture, and forestry. The gas supply has not been modelled per sector in each country rather national gas supply for each country has been modelled in the region. [↑](#footnote-ref-8)
8. Using LEAP's vocabulary, this energy production sector is often called a "transformation module". However, in this study, some modules represent more than one energy production sector, so for simplicity, the term "energy production module" describes a group of processes that produce one output fuel. [↑](#footnote-ref-9)
9. Typically, the peak gas demand for an entire year may occur only for one hour or one day. However, no gas demand data were available at a level of detail finer than one month, and as a result, SEI uses the average capacity requirements during this month as a proxy for peak demand. [↑](#footnote-ref-10)
10. Imports from Russia or Belarus are represented in the model, but the capacity means these imports cannot produce energy after April 2022. As a result, these imports only play a role in the model's scenarios during the first part of the first year. [↑](#footnote-ref-11)
11. For computational reasons, the percentage of each is allowed to drift by +/- 1%, applied to the target percentage in each year. For example, if hydrogen is to provide 1.5% of the energy content in pipeline gas in a particular year, this constraint would be satisfied by a hydrogen blend between 1.485% and 1.515%. [↑](#footnote-ref-12)
12. Based on the assumptions and hydrogen studies in the EU, the study considered that before 2041, the current pipeline infrastructure would be repurposed for 100% hydrogen in the gas pipelines. [↑](#footnote-ref-13)
13. This assumption has been taken by considering the ongoing feasibility study on UGS in Latvia. [↑](#footnote-ref-14)
14. F**or the detailed gas mix and gas demand assumptions, see the attached file in Annex A**. [↑](#footnote-ref-15)
15. GAASITARBIMISE PUHTALE ENERGIALE ÜLEMINEKU UURING, EESTI GAASITARBIMISE PROGNOOS KUNI 2050. AASTANI

    https://elering.ee/sites/default/files/2021-10/Eesti%20gaasitarbimise%20uuring.pdf [↑](#footnote-ref-16)
16. European Union’s Reference Scenario 2020 [↑](#footnote-ref-17)
17. In consultation with European Commission – DG Energy, the Fuel Cells and Hydrogen Joint Undertaking published a study on the ‘Opportunities for Hydrogen Energy Technologies Considering the National Energy & Climate Plans.

    https://www.fchobservatory.eu/news-events/new-study-released-opportunities-hydrogen-energy-technologies-considering-national [↑](#footnote-ref-18)
18. Average projection values from both sources [↑](#footnote-ref-19)
19. https://cleanenergynews.ihsmarkit.com/research-analysis/recordhigh-price-forecasts-across-global-carbon-markets-and-st.html#:~:text=In%20the%20EU%20ETS%2C%20the,2021%2C%20according%20to%20Platts%20assessments. [↑](#footnote-ref-20)
20. https://www.reuters.com/world/europe/analysts-nudge-eu-carbon-price-forecasts-higher-warn-ukraine-risks-2022-04-29/ [↑](#footnote-ref-21)
21. https://irena.org/publications/2022/Jul/Renewable-Power-Generation-Costs-in-2021 [↑](#footnote-ref-22)
22. https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf [↑](#footnote-ref-23)
23. F**or the detailed gas mix and gas demand assumptions, see the attached file in Annex A**. [↑](#footnote-ref-24)
24. https://ec.europa.eu/energy/sites/ener/files/documents/01.b.01\_mf31\_presentation\_ec\_gas\_2050\_infra\_study\_amilhat.pdf [↑](#footnote-ref-25)
25. Average projection values from both sources [↑](#footnote-ref-26)
26. F**or the detailed gas mix and gas demand assumptions, see the attached file in Annex A**. [↑](#footnote-ref-27)
27. Average projection values from both sources [↑](#footnote-ref-28)
28. F**or the detailed gas mix and gas demand assumptions, see the attached file in Annex A**. [↑](#footnote-ref-29)
29. Average projection values from both sources [↑](#footnote-ref-30)
30. Considering the national hydrogen production target and technical limitation of gas pipelines. [↑](#footnote-ref-31)
31. The assumption on the regional gas mix can be found in the attached document in Annex A [↑](#footnote-ref-32)
32. The combined pipeline and off-network gas supply capacity from different feedstocks [↑](#footnote-ref-33)
33. The results are similar for all the scenarios, with no gas import from GIPL to the RGMCG region. [↑](#footnote-ref-34)
34. The statement and assumptions are similar for all the scenarios. [↑](#footnote-ref-35)
35. In section 8.4 explains the repurposing of unused LNG terminal capacity. [↑](#footnote-ref-36)
36. The gas flow indicated in the following figure is the sum of gas flow in each month of the year. So, flow can be higher/lower/nil in some months. [↑](#footnote-ref-37)
37. The statement is similar for all the following scenarios. [↑](#footnote-ref-38)
38. NG requirement for each country is stated in section 3.1. [↑](#footnote-ref-39)
39. The assumptions and statements are similar for all the scenarios. [↑](#footnote-ref-40)
40. For LCOE calculation methodology, please refer to the section ‘**Levelised costs of producing renewable gases**’. [↑](#footnote-ref-41)
41. The reasoning is similar for all the scenarios. [↑](#footnote-ref-42)
42. In section 8.4 explains the repurposing of unused LNG terminal capacity. [↑](#footnote-ref-43)
43. Biomethane plants follow a constant production pattern at the sub-annual level. Hydrogen and SNG production will follow the load factor of wind power at the sub-annual level. [↑](#footnote-ref-44)
44. NG requirement for each country in the REN-Methane scenario is stated in section 4.1. [↑](#footnote-ref-45)
45. The gas flow indicated in the following figure is the sum of gas flow in each month of the year. So, flow can be higher/lower/nil in some months. [↑](#footnote-ref-46)
46. In section 8.4 explains the repurposing of unused LNG terminal capacity. [↑](#footnote-ref-47)
47. The gas flow indicated in the following figure is the sum of gas flow in each month of the year. So, flow can be higher/lower/nil in some months. [↑](#footnote-ref-48)
48. LNG capacity will be supplied by the existing/planned terminal in the region to the country. No new capacity deployment is needed. [↑](#footnote-ref-49)
49. Biomethane plants follow a constant production pattern at the sub-annual level. Hydrogen and SNG production will follow the load factor of wind power at the sub-annual level. [↑](#footnote-ref-50)
50. Due to the lifetime expiration of the plant, the model has retired some capacity of the biomethane plant for Lithuania. Still, based on the gas demand, the biomethane plant capacity can be renewed after 2047. [↑](#footnote-ref-51)
51. https://acer.europa.eu/Official\_documents/Acts\_of\_the\_Agency/Publication/Transporting%20Pure%20Hydrogen%20by%20Repurposing%20Existing%20Gas%20Infrastructure\_Overview%20of%20studies.pdf [↑](#footnote-ref-52)
52. https://www.elengy.com/images/Technical-economic-conditions-for-injecting-hydrogen-into-natural-gas-networks-report2019.pdf [↑](#footnote-ref-53)
53. Consultations with Amber Grid (Lithuanian TSO) and Elering Estonian (TSO) [↑](#footnote-ref-54)
54. <https://www.marcogaz.org/wp-content/uploads/2019/09/H2-Infographic.pdf> [↑](#footnote-ref-55)
55. https://acer.europa.eu/Official\_documents/Acts\_of\_the\_Agency/Publication/Transporting%20Pure%20Hydrogen%20by%20Repurposing%20Existing%20Gas%20Infrastructure\_Overview%20of%20studies.pdf [↑](#footnote-ref-56)
56. https://gasforclimate2050.eu/wp-content/uploads/2022/04/EHB-A-European-hydrogen-infrastructure-vision-covering-28-countries.pdf [↑](#footnote-ref-57)
57. Pipeline diameters are categorised based on the EHB 2022 classification: Small < 28 inches, Medium 28-37 inches, Large > 37 inches [↑](#footnote-ref-58)
58. Since no exact data is available on pipeline diameters, it is assumed that 75% of the overall TSO lines are medium-diameter and 25% are large-diameter pipelines. [↑](#footnote-ref-59)
59. https://gasforclimate2050.eu/wp-content/uploads/2022/10/2022\_Facilitating\_hydrogen\_imports\_from\_non-EU\_countries.pdf [↑](#footnote-ref-60)
60. https://bv.com/perspectives/converting-lng-import-terminals-ammonia-import-terminals [↑](#footnote-ref-61)
61. Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy. Energy Transition Commission, April 2021. [↑](#footnote-ref-62)
62. https://acer.europa.eu/Official\_documents/Acts\_of\_the\_Agency/Publication/Transporting%20Pure%20Hydrogen%20by%20Repurposing%20Existing%20Gas%20Infrastructure\_Overview%20of%20studies.pdf. [↑](#footnote-ref-63)
63. https://www.iea.org/commentaries/is-carbon-capture-too-expensive [↑](#footnote-ref-64)
64. Estonia 2.4 TWh, Latvia 2.7 TWh, Lithuania 8TWh, Finland 11 TWh [↑](#footnote-ref-65)
65. Economic feasibility of each country's biomethane potential is considered. [↑](#footnote-ref-66)
66. Communication with Conexus Baltic Grid [↑](#footnote-ref-67)
67. <https://h2-project-visualisation-platform.entsog.eu/> [↑](#footnote-ref-68)
68. https://task44.ieabioenergy.com/wp-content/uploads/sites/12/2021/12/Task-44-Best-Practice\_e-gas-Werlte\_Germany.pdf [↑](#footnote-ref-69)
69. https://www.movingpower.at/projekte/power-to-gas-werlte/?lang=en [↑](#footnote-ref-70)
70. https://www.conexus.lv/latvias-gas-transmission-system [↑](#footnote-ref-71)
71. https://www.ambergrid.lt/en/transmission-system/gas-transmission-system-in-Lithuania [↑](#footnote-ref-72)
72. https://enmin.lrv.lt/en/sectoral-policy/natural-gas-sector [↑](#footnote-ref-73)
73. https://iea.blob.core.windows.net/assets/97a133e9-4565-4388-9c17-7dfacb6bcf2c/CountryChapterFinland.pdf [↑](#footnote-ref-74)
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75. https://elering.ee/sites/default/files/attachments/Estonian\_gas\_transmission\_network\_development\_plan\_2018\_2027.pdf [↑](#footnote-ref-76)
76. Average projection values from both sources [↑](#footnote-ref-77)
77. https://cleanenergynews.ihsmarkit.com/research-analysis/recordhigh-price-forecasts-across-global-carbon-markets-and-st.html#:~:text=In%20the%20EU%20ETS%2C%20the,2021%2C%20according%20to%20Platts%20assessments. [↑](#footnote-ref-78)
78. https://www.reuters.com/world/europe/analysts-nudge-eu-carbon-price-forecasts-higher-warn-ukraine-risks-2022-04-29/ [↑](#footnote-ref-79)
79. https://www.getbaltic.com/en/market-data/trading-data/ [↑](#footnote-ref-80)
80. https://www.bnnbloomberg.ca/citi-says-high-europe-gas-prices-to-stay-until-later-in-decade-1.1815777 [↑](#footnote-ref-81)
81. https://irena.org/publications/2022/Jul/Renewable-Power-Generation-Costs-in-2021 [↑](#footnote-ref-82)
82. https://www.lazard.com/media/451905/lazards-levelized-cost-of-energy-version-150-vf.pdf [↑](#footnote-ref-83)
83. https://eepublicdownloads.entsoe.eu/clean-documents/sdc-documents/MAF/2020/Pan-European Climate Database.7z [↑](#footnote-ref-84)
84. <https://www.kn.lt/en/our-activities/lng-terminals/klaipeda-lng-terminal/559>. (The same utilisation curve us chosen for the existing, planned and new terminals in the region) [↑](#footnote-ref-85)