Gas Decarbonisation Pathways for Estonia

(3 Baltic states + Finland)

Deliverable 8: Final report

27 November 2023

This project is carried out with funding by the European Union via the Structural Reform Support Programme and in cooperation with the Directorate General for Structural Reform Support of the European Commission

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In association with:

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Summary

Between August 2022 and January 2023, there was a notable decline in natural gas consumption in the EU, with a decrease of 19.3% compared to the average of the same months from 2017 to 2022. Significantly, the Baltic countries recorded much higher reductions in their gas consumption. Lithuania saw a decrease of nearly 50%, Latvia 36%, and Estonia 32%, while Finland recorded a reduction of 57%, which was the highest in the whole EU. These drastic changes in gas demand in the Baltic countries and Finland came after they took initiatives to phase out gas supplies from Russia, following Russia's invasion of Ukraine in February 2022[1].

However, natural gas still covers a considerable share in the energy mix and hence represents an important source of greenhouse gas emissions in the Baltic Regional Gas Market (Estonia, Latvia, Lithuania and Finland). Fossil gas demand must be further reduced and substituted by renewable and low-carbon electricity and gases if the region is to achieve net full decarbonisation by 2050 as well as increase energy security by reducing its exposure to high fossil gas prices and external supply shocks.

The project provides recommendations on a regulatory for decarbonising the regional gas market by 2050. To arrive at these recommendations, the project conducted the following activities:

- ✓ Development of a business-as-usual and 3 gas decarbonisation scenarios for the region (Deliverable 3)
- ✓ Assessment of scenario impacts on the energy system and wider economy of the region (Deliverable 4)
- ✓ Assessment of risks to achieving the decarbonisation scenarios (Deliverable 5)
- ✓ Conduction of a sensitivity analysis on the scenarios (Deliverable 6)
- ✓ Development of an action plan for decarbonising the regional gas market, including measures on the regulatory framework (Deliverable 7)

Selected results from the main deliverables are presented next.

Scenario development and impact assessment

To guide the analysis the study team has developed a **Business-as-usual (BAU) scenario** as well as three gas decarbonisation scenarios, of which the main characteristics are presented in Table 1:

- ✓ **Renewable methane (REN-Methane) scenario**, leveraging biogas and biomethane for on- and off-grid applications, reserving hydrogen for off-grid hard-to-decarbonise applications;
- ✓ **Renewable hydrogen (REN-Hydrogen) scenario**, with on- and off-grid use of hydrogen and development of a regional cross-border hydrogen network by 2050;
- ✓ **Cost Minimal scenario (CM)**, exploring competition between renewable gases and natural gas, to find the least cost based decarbonisation solution for the modelled period, given set constraints and modelling boundaries.

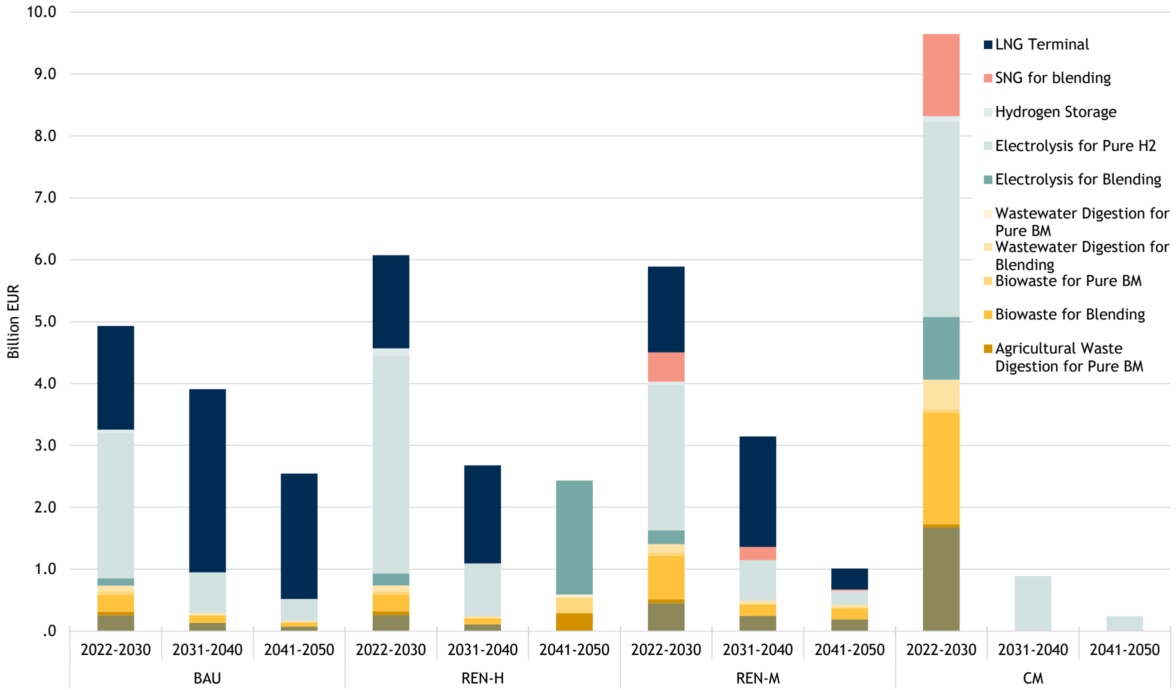
[1] https://ec.europa.eu/eurostat/web/products-eurostat-news/w/DDN-20230221-1

Table 1 Summary of BAU and gas decarbonisation scenarios for the Baltic+Finland region

		BAU		Biomethane		Hydrogen		Cost Minimal	
	Unit	2030	2050	2030	2050	2030	2050	2030	2050
Supply	**TWh**	60.79	53.15	53.10	37.80	52.22	37.80	52.21	37.77
LNG imports	TWh	49.56	27.33	35.38	0.00	38.63	0.00	16.53	0.00
Biomethane (of which on-grid)	TWh	4.78 (4.47)	11.14 (10.83)	9.38 (9.07)	22.59 (22.28)	4.83 (4.52)	6.40 (0.00)	24.10 (23.79)	22.42 (22.11)
Hydrogen (of which on-grid)	TWh	4.62 (0.82)	12.85 (0.58)	5.33 (1.53)	11.66 (0.86)	6.93 (1.33)	29.57 (18.93)	6.42 (1.39)	13.52 (0.00)
SNG on-grid	TWh	0.00	0.00	1.18	1.72	0.00	0.00	3.33	0.00
Biogas off-grid	TWh	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83
Gas production installed capacity	**GW**	2.99	7.95	3.98	9.38	4.08	15.20	7.22	11.38
Biomethane	GW	0.70	1.56	1.33	3.12	0.70	1.04	3.29	3.29
Electrolytic hydrogen	GW	2.05	6.14	2.28	5.62	3.14	13.91	2.90	7.06
SNG	GW	0.00	0.00	0.37	0.64	0.00	0.00	1.03	1.03
Biogas	GW	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Renewable electricity needs for gas production	**TWh**	6.80	17.30	10.00	18.60	10.20	39.90	8.90	18.20
Storage capacity	**-**	-	-	-	-	-	-	-	-
Methane gases	TWh	12.24	12.53	12.33	10.65	12.24	12.17	12.24	10.77
Hydrogen	TWh	0.15	0.15	0.15	0.15	0.29	0.29	0.23	0.23
LNG terminal capacities	**TWh/y**	164	112	163	86	163	82	158	67
Average LCOE	**-**	-	-	-	-	-	-	-	-
Natural gas with ETS	EUR/MWh	113	138	113	138	113	138	113	138
Biomethane	EUR/MWh	77	55	71	52	82	57	65	53
Hydrogen	EUR/MWh	269	102	264	101	266	96	224	121
Average yearly cost to consumers	**-**	-	-	-	-	-	-	-	-
Households	EUR/y	666	496	760	265	675	402	677	229
Commercial users	EUR/y	13 651	10 184	15 611	5 427	13 844	8 234	13 900	4 667
GHG emissions	**Million ton CO2eq**	8.94	5.09	6.32	0.18	6.73	0.38	2.73	0.18

Based on the economic and energy system impacts assessment undertaken, all three gas decarbonisation scenarios present major economic and energy system benefits compared to the BAU scenario. Although the decarbonisation pathways require higher investment levels than the BAU scenario (see Figure 3-6), the positive direct and indirect impacts in terms of economic output, employment, energy costs, import dependence, outweigh the higher overall capital expenditures. Moreover, the Cost Minimal scenario is preferred from both the economic and energy system impacts perspectives, reaching a phase-out of LNG imports and full decarbonisation of the regional gas system already by 2040, while the other decarbonisation scenarios achieve this only after 2040.

Figure 1 CAPEX for the gas system and renewable electricity generation for electrolysis for the study scenarios



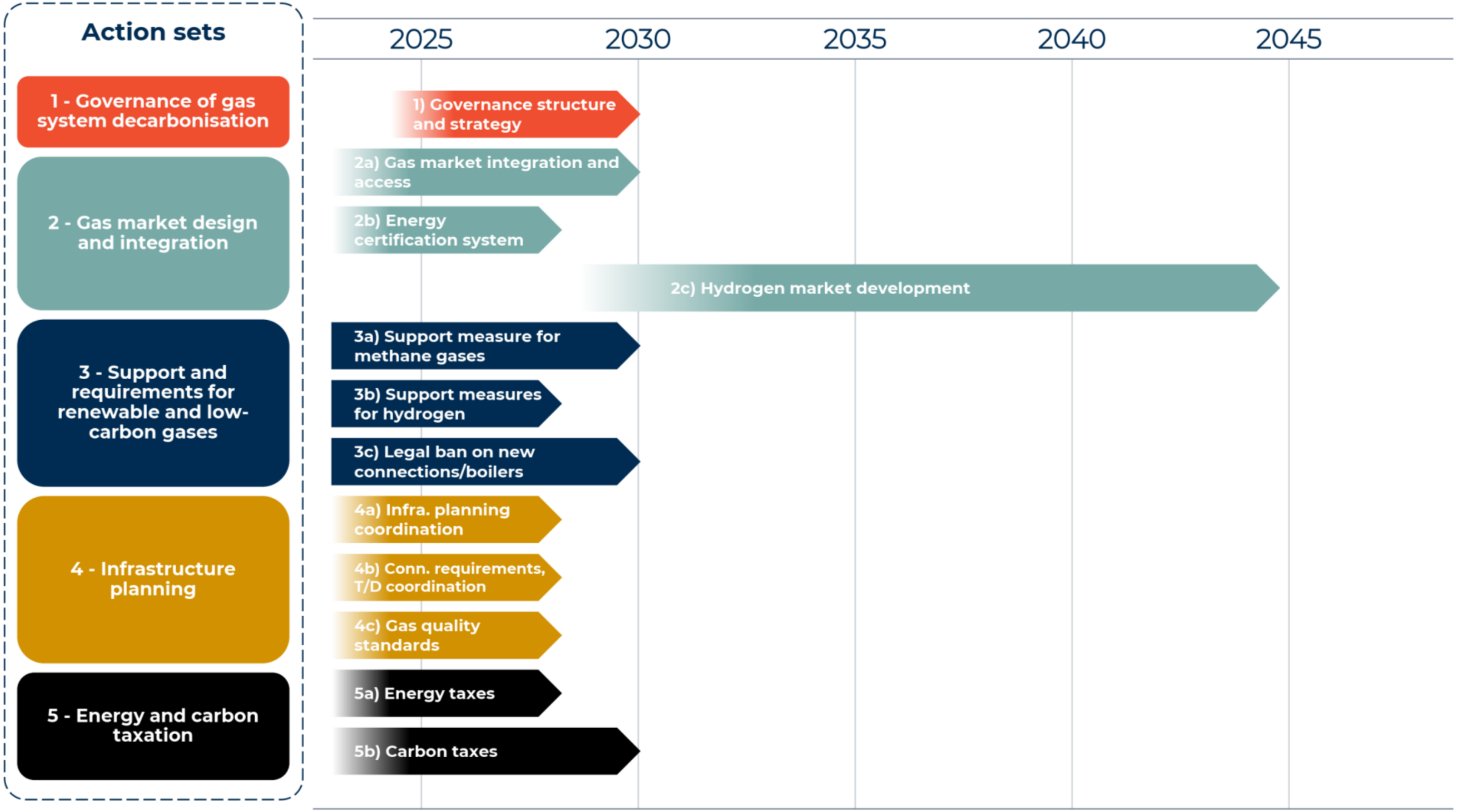
Scenario risk analysis

The main risks identified for achieving the three gas decarbonisation scenarios were related to various economic, regulatory and technical factors which may hinder the deployment of decarbonisation assets. Specifically, they concern the risks associated with 1) economic turndowns and instability; 2) issues with developing the necessary infrastructure; 3) future gas supply disruptions; 4) limits to the renewable energy potential (wind or biomass-based); 5) lock-in on or asset stranding of natural gas; 6) regulatory uncertainty slowing down investments; and 7) insufficient cost or performance improvement of key gas decarbonisation technologies.

Action plan development

To address these risks and fully decarbonise the regional gas system, the plan details 12 actions separated in 5 categories: 1) Governance of gas system decarbonization; 2) Gas market design and integration; 3) Support and requirements for renewable and low-carbon gas production and/or consumption; 4) Infrastructure planning; and 5) Energy and carbon taxation. Each of the individual measures in the 5 categories is further detailed regarding the implementation timeline, as shown in the roadmap of Figure 3-11.

Figure 2 Action timeline for decarbonisation of the gas system of the Baltic states and Finland



The proposed actions consist of new or updated provisions in the regulatory framework of the Baltic Regional Gas Market countries, as well as additional non-regulatory measures such as on regional coordination between national stakeholders. The actions proposed address all main risks identified for achieving the scenarios, as illustrated in Figure 3-10.

Figure 3 Action plan measures and risks addressed

The actions of the plan are further broken-down in the report in underlying individual measures, including the value chain steps they impact (from gas production to transport, trading and consumption), the relevant gas types (biogas/biomethane or hydrogen), and the implementation geography (all four Member States jointly, separately, or only certain individual Member States). National authorities (especially ministries, but also national energy regulators) and network operators are already undertaking some of the proposed actions, and should use this plan to further reform the regulatory framework and increase regional cooperation for decarbonisation of the gas system.

Kokkuvõte (Estonian summary)

2022. aasta augustist kuni 2023. aasta jaanuarini toimus ELis märkimisväärne maagaasi tarbimise vähenemine, langedes 19,3 % võrreldes samade kuude keskmisega aastatel 2017-2022. Märkimisväärselt oli Balti riikides gaasitarbimise vähenemine eelmainitust tunduvalt suurem. Leedus oli vähenemine peaaegu 50%, Lätis 36% ja Eestis 32%, samas kui Soomes oli vähenemine EL suurim - 57%. Sellised drastilised muutused Balti riikide ja Soome gaasinõudluses toimusid pärast Balti riikide algatusi Venemaalt pärit gaasitarnete järkjärguliseks lõpetamiseks peale Venemaa sissetungi Ukrainasse veebruaris 2022[2].

Siiski katab maagaas endiselt märkimisväärse osa energiaallikate kogumist ja on seega oluline kasvuhoonegaaside heitkoguste allikas Balti piirkondlikul gaasiturul (Eesti, Läti, Leedu ja Soome). Kui piirkond soovib 2050. aastaks saavutada täieliku süsinikdioksiidi heitkoguste vähendamise ning suurendada energiajulgeolekut, tuleb fossiilse gaasi nõudlust veelgi vähendada ning asendada see taastuvenergia ja vähese süsinikdioksiidiheitega elektri ja gaasiga, vähendades seega sõltuvust kõrgetest fossiilse gaasi hindadest ja välistest tarnešokkidest.

Projektis esitatakse soovitused piirkondliku gaasituru dekarboniseerimiseks 2050. aastaks. Soovituste väljatöötamiseks viidi projekti raames läbi järgmised tegevused:

- ✓ Piirkonna jaoks "tavapärase äritegevuse" (ENG: business-as-usual, BAU) ja kolm gaasisektori süsinikdioksiidi heite vähendamise stsenaariumi väljatöötamine (3. väljund).
- ✓ Stsenaariumide mõju hindamine piirkonna energiasüsteemile ja majandusele laiemalt (4. väljund).
- ✓ Süsinikdioksiidi heite vähendamise stsenaariumide saavutamisega seotud riskide hindamine (5. väljund).
- ✓ Stsenaariumide tundlikkusanalüüsi läbiviimine (6. väljund)
- ✓ Piirkondliku gaasituru dekarboniseerimiseks tegevuskava väljatöötamine, sealhulgas meetmed reguleeriva raamistiku kohta (7. väljund).

Järgnevalt esitatakse peamised tulemused.

Stsenaariumide väljatöötamine ja mõju hindamine

Analüüsi läbiviimiseks on uurimisrühm töötanud välja **tavapärase äritegevuse stsenaariumi ning** kolm stsenaariumi, mille peamised omadused on esitatud tabelis 1:

- ✓ **Taastuva metaani (REN-Methane) stsenaarium**, mis kasutab biogaasi ja biometaani võrgupõhiste ja -väliste lahenduste jaoks, eelistades vesinikku võrguväliste raskesti dekarboniseeritavate lahenduste jaoks;
- ✓ **Taastuva vesiniku (REN-Hydrogen) stsenaarium,** mis hõlmab vesiniku kasutamist võrgus ja väljaspool võrku ning piirkondliku piiriülese vesiniku võrgustiku arendamist 2050. aastaks;
- ✓ **Minimaalse kulu stsenaarium (Cost Minimal, CM),** mis uurib konkurentsi taastuvate gaaside ja maagaasi vahel, et leida vähima kulupõhise dekarboniseerimise lahendus modelleeritud perioodil, arvestades seatud piiranguid ja modelleerimise piire.

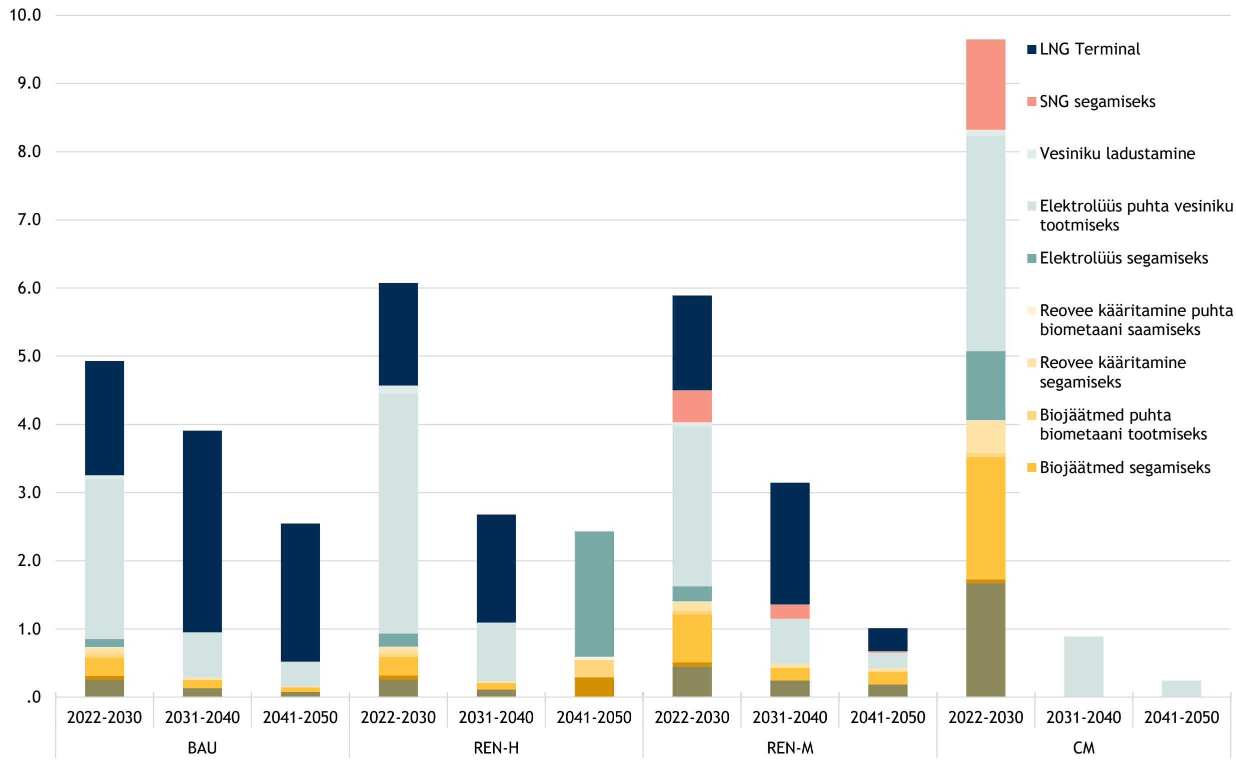
[2] https://ec.europa.eu/eurostat/web/products-eurostat-news/w/DDN-20230221-1

Tabel 1. Balti+Soome piirkonna BAU ja gaasi dekarboniseerimise stsenaariumide kokkuvõte

		BAU		REN-Methane		REN-Hydrogen		Cost Minimal	
	Üksus	2030	2050	2030	2050	2030	2050	2030	2050
Tarne	**TWh**	60.79	53.15	53.10	37.80	52.22	37.80	52.21	37.77
Veeldatud maagaasi import	TWh	49.56	27.33	35.38	0.00	38.63	0.00	16.53	0.00
Biometaan (sellest võrgupõhine)	TWh	4.78 (4.47)	11.14 (10.83)	9.38 (9.07)	22.59 (22.28)	4.83 (4.52)	6.40 (0.00)	24.10 (23.79)	22.42 (22.11)
Vesinik (sellest võrgupõhine)	TWh	4.62 (0.82)	12.85 (0.58)	5.33 (1.53)	11.66 (0.86)	6.93 (1.33)	29.57 (18.93)	6.42 (1.39)	13.52 (0.00)
SNG võrgupõhine	TWh	0.00	0.00	1.18	1.72	0.00	0.00	3.33	0.00
Biogaas võrguväline	TWh	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83
Gaasitootmise installeeritud võimsus	**GW**	2.99	7.95	3.98	9.38	4.08	15.20	7.22	11.38
Biometaan	GW	0.70	1.56	1.33	3.12	0.70	1.04	3.29	3.29
Elektrolüütiline vesinik	GW	2.05	6.14	2.28	5.62	3.14	13.91	2.90	7.06
SNG	GW	0.00	0.00	0.37	0.64	0.00	0.00	1.03	1.03
Biogaas	GW	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Taastuva elektrienergia vajadus gaasi tootmiseks	**TWh**	6.80	17.30	10.00	18.60	10.20	39.90	8.90	18.20
Talletamisvõimsus	**-**	-	-	-	-	-	-	-	-
Metaanigaasid	TWh	12.24	12.53	12.33	10.65	12.24	12.17	12.24	10.77
Vesinik	TWh	0.15	0.15	0.15	0.15	0.29	0.29	0.23	0.23
LNG-terminali võimsus	**TWh/a**	164	112	163	86	163	82	158	67
Keskmine LCOE	**-**	-	-	-	-	-	-	-	-
Maagaas koos heitkogustega kauplemise süsteemiga	EUR/MWh	113	138	113	138	113	138	113	138
Biometaan	EUR/MWh	77	55	71	52	82	57	65	53
Vesinik	EUR/MWh	269	102	264	101	266	96	224	121
Keskmine aastane kulu tarbijatele	**-**	-	-	-	-	-	-	-	-
Kodumajapidamised	EUR/a	666	496	760	265	675	402	677	229
Kommertskasutajad	EUR/a	13 651	10 184	15 611	5 427	13 844	8 234	13 900	4 667
Kasvuhoonegaaside heitkogused	**Miljon tonni CO2-ekvivalenti**	8.94	5.09	6.32	0.18	6.73	0.38	2.73	0.18

Majanduse ja energiasüsteemi mõju hindamise põhjal on kõik kolm gaasi dekarboniseerimise stsenaariumi võrreldes BAU stsenaariumiga majanduslikult ja energiasüsteemi seisukohast väga kasulikud. Kuigi süsinikdioksiidi heite vähendamise viisid nõuavad suuremaid investeeringuid kui BAU stsenaarium (vt. Jonnis 1), kaaluvad positiivsed otsesed ja kaudsed mõjud majandustoodangu, tööhõive, energiakulude ja impordisõltuvuse osas üles suuremad üldised kapitalikulud. Lisaks sellele on nii majandusmõju kui ka energiasüsteemi mõju seisukohast eelistatum stsenaarium "Cost Minimal", mille puhul saavutatakse veeldatud maagaasi impordi järkjärguline lõpetamine ja piirkondliku gaasisüsteemi täielik dekarboniseerimine juba 2040. aastaks, samal ajal kui teiste dekarboniseerimise stsenaariumide puhul saavutatakse see alles pärast 2040. aastat.

Joonis 1. Gaasisüsteemi ja elektrolüüsi taastuvenergia tootmise CAPEX uuringustsenaariumide puhul



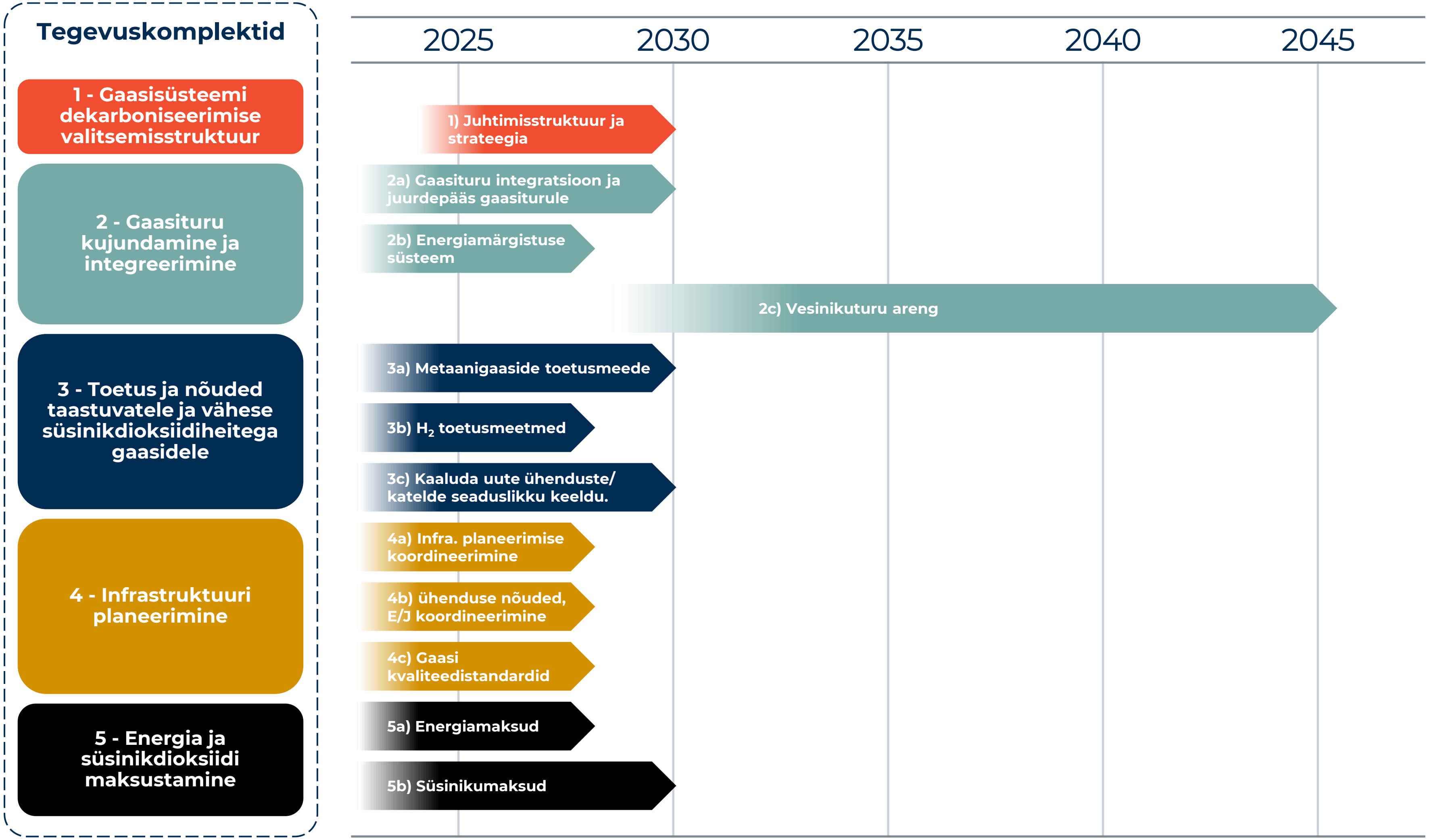
Stsenaariumi riskianalüüs

Peamised riskid, mis tuvastati kolme gaasi dekarboniseerimise stsenaariumi saavutamisel, olid seotud erinevate majanduslike, regulatiivsete ja tehniliste teguritega, mis võivad takistada dekarboniseerimisvahendite kasutuselevõttu. Konkreetsemalt sisaldavad need riske, mis on seotud 1) majanduslanguse ja ebastabiilsusega; 2) vajaliku infrastruktuuri arendamisega seotud probleemidega; 3) tulevaste gaasivarustuse häiretega; 4) taastuvenergia potentsiaali piiramisega (tuule- või biomassipõhine energia); 5) maagaasi kasutamise piiramisega või varade seisakuga; 6) investeeringute aeglustamisega seoses regulatiivse ebakindlusega; ja 7) põhiliste gaasistamise tehnoloogiate hinna või jõudluse ebapiisava parandamisega.

Tegevuskava väljatöötamine

Nende riskide käsitlemiseks ja piirkondlikus gaasisüsteemis täieliku süsinikneutraalsuse saavutamiseks on kavas esitatud 12 meedet, mis on jaotatud 5 kategooriasse: 1) Gaasisüsteemi dekarboniseerimise valitsemisstruktuur 2) gaasituru kujundamine ja integreerimine; 3) taastuvenergia ja vähese süsinikdioksiidiheitega gaasi tootmise ja/või tarbimise toetamine ja nõuded; 4) infrastruktuuri kavandamine; ja 5) energia ja süsinikdioksiidi maksustamine. Iga üksiku meetme rakendamise ajakava viies kategoorias on üksikasjalikumalt kirjeldatud teekaardil joonisel 2.

Joonis 2. Balti riikide ja Soome gaasisüsteemi dekarboniseerimise ajakava



Kavandatavad meetmed hõlmavad uusi või ajakohastatud sätteid Balti piirkondliku gaasituru riikide reguleerivas raamistikus, samuti täiendavaid mitteregulatiivseid meetmeid, näiteks riiklikke sidusrühmadevahelist piirkondlikku koordineerimist. Kavandatud meetmed on suunatud kõigile peamistele stsenaariumide saavutamisega seotud riskidele, nagu on näidatud joonisel 3.

Joonis 3. Tegevuskava meetmed ja käsitletavad riskid

Kavas esitatud meetmed on aruandes jaotatud üksikute meetmete alla, sealhulgas väärtusahela etapid, mida nad mõjutavad (gaasitootmisest kuni transpordi, kaubanduse ja tarbimiseni), asjaomased gaasitüübid (biogaas/biometaan või vesinik) ja rakendamise geograafia (kõik neli liikmesriiki koos, eraldi või ainult teatavad liikmesriigid). Riiklikud asutused (eelkõige ministeeriumid, kuid ka riiklikud energeetikasektorit reguleerivad asutused) ja võrguettevõtjad võtavad juba praegu osa kavandatud meetmetest ning peaksid kasutama käesolevat kava reguleeriva raamistiku edasiseks reformimiseks ja piirkondliku koostöö suurendamiseks, et vähendada süsinikdioksiidi heitkoguseid gaasisüsteemis.

Santrauka (Lithuanian summary)

Nepaisant to, kad pastaraisiais metais gamtinių dujų vartojimas sumažėjo, jos sudaro didelę dalį energijos rūšių derinio, todėl yra svarbus šiltnamio efektą sukeliančių dujų šaltinis Baltijos regioninėje dujų rinkoje (Estijoje, Latvijoje, Lietuvoje ir Suomijoje). Norint iki 2050 m. visiškai sumažinti iškastinių dujų poreikį ir pakeisti jas atsinaujinančiomis ir mažai anglies dioksido į aplinką išskiriančiomis dujomis ir elektros energija, būtina toliau mažinti iškastinių dujų paklausą, ir tuo būdu mažinti aukštų iškastinių dujų kainų ir išorinių tiekimo šoko poveikį.

Studijoje pateiktos rekomendacijos dėl veiksmų, įskaitant naujus teisės aktus, kaip iki 2050 m. sumažinti anglies dioksido išmetimą regioninėje dujų rinkoje. Šią studiją finansavo Europos Sąjunga pagal Techninės paramos priemonę, o nuo 2022 m. vasario mėn. iki 2023 m. spalio mėn. įgyvendino bendrovė Trinomics kartu su Stockholm Environment Institute ir E3-Modelling, glaudžiai bendradarbiaudama su Europos Komisija.

Scenarijų rengimas ir poveikio vertinimas

Atlikdama analizę, tyrimo grupė parengė įprastinės veiklos scenarijų ir tris dujų išmetimo mažinimo scenarijus: 1) atsinaujinančio metano (REN-metano) scenarijus, 2) atsinaujinančio vandenilio (REN-vandenilio) scenarijus ir 3) minimalių sąnaudų scenarijus (CM).

Remiantis atliktu poveikio ekonomikai ir energetikos sistemai vertinimu, **visi trys dujų išmetimo mažinimo scenarijai,** palyginti su alternatyviu scenarijumi, yra labai naudingi ekonomikai ir energetikos sistemai. Nors anglies dioksido išmetimo mažinimo būdams įgyvendinti reikia didesnių investicijų nei pagal įprastinį (BAU) scenarijų, teigiamas tiesioginis ir netiesioginis poveikis ekonominei veiklai (gamybai), užimtumui, energijos sąnaudoms, priklausomybei nuo importo nusveria didesnes bendras kapitalo išlaidas. Be to, **tiek ekonominiu, tiek poveikio energetikos sistemai požiūriu palankesnis yra minimalių sąnaudų scenarijus**.

Scenarijaus rizikos analizė

Pagrindinė nustatyta rizika, susijusi su trimis anglies dioksido išmetimo mažinimo scenarijais, buvo susijusi su įvairiais ekonominiais, reguliavimo ir techniniais veiksniais, kurie gali trukdyti diegti anglies dioksido išmetimo mažinimo technologijas. Šių veiksnių rizika galimai būtų susijusi su: 1) ekonomikos nuosmukiu ir nestabilumu; 2) reikiamos infrastruktūros plėtros problemomis; 3) būsimais dujų tiekimo sutrikimais; 4) atsinaujinančių energijos išteklių (vėjo ar biomasės) potencialo ribotumu; 5) gamtinių dujų suvaržymu arba turto nenumatytu ar priešlaikiniu nurašymu; 6) reguliavimo neapibrėžtumu, dėl kurio lėtėja investicijos; ir 7) nepakankamu pagrindinių dujų dekarbonizacijos technologijų sąnaudų mažėjimu ar našumo padidėjimu.

Veiksmų plano rengimas

Siekiant pašalinti šias rizikas ir visiškai dekarbonizuoti regioninę dujų sistemą, plane numatyta 12 veiksmų, suskirstytų į 5 kategorijas: 1) dujų sistemos dekarbonizavimo valdysena; 2) dujų rinkos kūrimas ir integravimas; 3) parama ir reikalavimai atsinaujinančių išteklių ir mažai anglies dioksido į aplinką išskiriančių dujų gamybai ir (arba) vartojimui; 4) infrastruktūros planavimas; 5) energijos ir anglies dioksido apmokestinimas.

Kopsavilkums (Latvian summary)

Neraugoties uz to, ka pēdējos gados dabasgāzes īpatsvars energoresursu bilancē ir samazinājies, dabasgāze aizņem ievērojamu daļu un tādējādi ir nozīmīgs siltumnīcefekta gāzu (SEG) emisiju avots Baltijas valstu reģionālajā gāzes tirgū (Igaunijā, Latvijā, Lietuvā un Somijā). Fosilās gāzes izmantošana ir jāturpina samazināt, un tā jāaizstāj ar atjaunojamo un mazoglekļa elektroenerģiju un gāzēm, lai līdz 2050. gadam panāktu reģiona pilnīgu dekarbonizāciju, kā arī samazinātu dabasgāzes cenu un piegādes risku ietekmi uz reģiona gāzes tirgu.

Projektā tika sniegti ieteikumi pasākumu, tostarp jaunus tiesību aktu, izstrādei, lai līdz 2050. gadam dekarbonizētu reģionālo gāzes tirgu. Projektu finansēja Eiropas Savienība ar Tehniskā atbalsta instrumenta starpniecību, un to īstenoja uzņēmums Trinomics sadarbībā ar Stockholm Environment Institute un E3-Modelling (pētnieku grupa) no 2022. gada februāra līdz 2023. gada oktobrim, cieši sadarbojoties ar Eiropas Komisiju.

Scenāriju izstrāde un ietekmes novērtējums

Lai veiktu analīzi, pētnieku grupa ir izstrādājusi esošās situācijas attīstības (*angl. Business-as-usual* vai BAU) scenāriju, kā arī trīs gāzes dekarbonizācijas scenārijus: 1) atjaunojamā metāna (*angl. REN-Methane*) scenārijs, 2) atjaunojamā ūdeņraža (*angl. REN-Hydrogen*) scenārijs un 3) minimālo izmaksu (*angl. Cost Minimal scenario* vai CM) scenārijs.

Pamatojoties uz veikto ietekmes uz ekonomiku un energosistēmu izvērtējumu, **visi trīs gāzes dekarbonizācijas scenāriji** sniedz būtiskākus ekonomikas un energosistēmas attīstības ieguvumus nekā BAU attīstības scenārijs. Lai gan sistēmas dekarbonizācijai ir nepieciešami lielāki ieguldījumi nekā BAU attīstības scenārija gadījumā, pozitīvā tiešā un netiešā ietekme uz ekonomikas attīstību, nodarbinātību, enerģijas izmaksām, atkarību no importa atsver salīdzinoši lielos kopējos kapitāla izdevumus. Turklāt, minimālo izmaksu (CM) scenārijs ir optimālākais **gan no ekonomikas, gan no energosistēmu attīstības viedokļa.**

Scenāriju riska analīze

Galvenie identificētie riski, kas saistīti ar trīs gāzes dekarbonizācijas scenāriju īstenošanu, ir saistīti ar dažādiem ekonomiskiem, normatīvā regulējuma un tehniskajiem faktoriem, kas varētu kavēt dekarbonizācijas scenāriju aktīvu ieviešanu. Visvairāk tie skar riskus , kas saistīti ar 1) ekonomikas lejupslīdi un nestabilitāti; 2) nepieciešamās infrastruktūras attīstību; 3) gāzes piegādes traucējumiem nākotnē; 4) atjaunojamo energoresursu (vēja vai biomasas) potenciāla ierobežojumiem; 5) dabasgāzes piegāžu bloķēšanu vai aizplūšanu; 6) normatīvā regulējuma nenoteiktību, kas palēnina ieguldījumus; un 7) galveno gāzes dekarbonizācijas tehnoloģiju izmaksu vai veiktspējas nepietiekamu uzlabošanos.

Rīcības plāna izstrāde

Lai novērstu šos riskus un pilnībā dekarbonizētu reģionālo gāzes sistēmu, plānā sīki analizēti 12 pasākumi, kas sadalīti 5 kategorijās: 1) gāzes sistēmas dekarbonizācijas pārvaldība; 2) gāzes tirgus izveide un integrācija; 3) atbalsts un prasības atjaunojamo energoresursu un zemu oglekļa dioksīda emisiju gāzes ražošanai un/vai patēriņam; 4) infrastruktūras plānošana; un 5) enerģijas un SEG nodokļi.

Tiivistelmä (Finnish summary)

Vaikka maakaasun osuus kaikista energianlähteistä on viime vuosina vähentynyt, se on silti huomattava ja siten myös merkittävä kasvihuonekaasupäästöjen lähde Baltian alueellisilla kaasumarkkinoilla (Viro, Latvia, Liettua ja Suomi). Fossiilisen maakaasun kysyntää on edelleen vähennettävä, ja se on korvattava uusiutuvalla ja vähähiilisellä sähköllä ja kaasulla, jos alueella halutaan saavuttaa täydellinen hiilidioksidipäästöjen vähentäminen vuoteen 2050 mennessä ja vähentää altistumista korkeille fossiilisen maakaasun hinnoille ja ulkoisille toimitushäiriöille.

Hankkeessa annettiin suosituksia sellaisten toimien, myös uuden lainsäädännön, kehittämiseksi, joilla alueelliset maakaasumarkkinat voidaan irrottaa hiilidioksidipäästöistä vuoteen 2050 mennessä. Hanketta rahoitti Euroopan unioni teknisen tuen välineen kautta, ja sen toteutti Trinomics apunaan Stockholm Environment Institute ja E3-Modelling helmikuun 2022 ja lokakuun 2023 välisenä aikana tiiviissä yhteistyössä Euroopan komission kanssa.

Skenaarioiden laatiminen ja vaikutusten arviointi

Tutkimusryhmä on laatinut analyysin ohjaamiseksi tavanomaisen liiketoiminnan skenaarion (BAU) sekä kolme maakaasun hiilidioksidipäästöjen vähentämisskenaariota: 1) Uusiutuva metaani (REN-Metaani) -skenaario, 2) Uusiutuva vety (REN-Vety) -skenaario ja 3) Kustannuksiltaan minimaalinen skenaario (CM).

Taloudellisten ja energiajärjestelmään kohdistuvien vaikutusten arvioinnin perusteella **kaikki kolme maakaasun hiilidioksidipäästöjen vähentämistä koskevaa skenaariota** tarjoavat merkittäviä taloudellisia ja energiajärjestelmään liittyviä etuja verrattuna BAU-skenaarioon. Vaikka hiilidioksidipäästöjen vähentämispolut edellyttävät suurempia investointeja kuin BAU-skenaario, myönteiset suorat ja välilliset vaikutukset, jotka liittyvät taloudelliseen tuotantoon, työllisyyteen, energiakustannuksiin ja tuontiriippuvuuteen, ovat suuremmat kuin kokonaispääomakustannukset. **Cost Minimal -skenaariota pidetään parhaimpana sekä taloudellisten että energiajärjestelmään kohdistuvien vaikutusten näkökulmasta**.

Skenaarioriskianalyysi

Suurimmat riskit, jotka tunnistettiin kolmen maakaasun hiilidioksidipäästöjen vähentämistä koskevan skenaarion toteuttamisessa, liittyivät erilaisiin taloudellisiin ja sääntelyyn liittyviin sekä teknisiin tekijöihin, jotka voivat estää hiilidioksidipäästöjen vähentämiseen tähtäävien resurssien käyttöönoton. Ne käsittävät erityisesti riskejä, jotka liittyvät 1) talouden laskusuhdanteisiin ja epävakauteen, 2) tarvittavan infrastruktuurin kehittämiseen liittyviin ongelmiin, 3) tuleviin kaasun toimitushäiriöihin, 4) uusiutuvien energialähteiden potentiaalin rajoituksiin (tuuli- tai biomassapohjaiset), 5) maakaasuun lukkiutumiseen tai omaisuuseriin, 6) investointeja hidastavaan sääntelyn epävarmuuteen ja 7) keskeisten fossiilisen maakaasun käyttöä vähentävien tekniikoiden riittämättömään kustannus- tai suorituskyvyn parantamiseen.

Toimintasuunnitelman kehittäminen

Edellä mainittujen riskien torjumiseksi ja alueellisen kaasujärjestelmän täydelliseksi hiilidioksidipäästöjen vähentämiseksi suunnitelmassa esitetään 12 toimenpidettä, jotka on jaettu viiteen luokkaan: 1) Kaasujärjestelmän hiilidioksidipäästöjen vähentämisen hallinnointi, 2)

Kaasumarkkinoiden suunnittelu ja integrointi, 3) Uusiutuvan ja vähähiilisen kaasun tuotannon ja/tai kulutuksen tukeminen ja vaatimukset, 4) Infrastruktuurin suunnittelu ja 5) Energia- ja hiilidioksidiverotus.

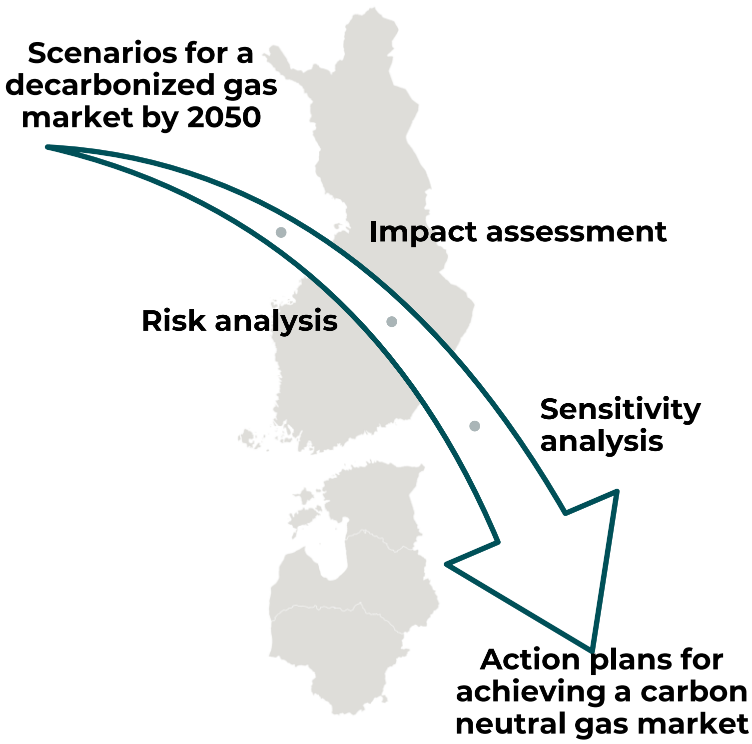
1 Introduction

This Deliverable 8 is the **final report that aims to present the relevant performed activities and deliverables conducted in the "Gas Decarbonisation Pathways" project**.

The objective of the project was to provide the European Commission's DG Reform and the project beneficiaries with the necessary recommendations for the development of a new legislative framework that allows to cost-efficiently decarbonise the Baltic Regional Gas Market by 2050.

As part of this study, the current gas system has been described and three climate-neutral pathways have been identified, of which the energy system impacts have been assessed via a modelling exercise. Further, a socioeconomic impact assessment and risk analysis have been carried out that were used as a basis for the development of a policy action plan, as illustrated in Figure 1-1. As Estonia is part of the highly integrated Baltic Regional Gas Market, the project had a strong regional focus, and all analysis was developed for the region as a whole, thus covering Estonia, Latvia, Lithuania and Finland.

Figure 1-1 Main deliverables of the project



The remainder of the report is structured as follows:

- Chapter 2 summarises the activities (meetings, reporting, consultations, key monitoring indicators) conducted during this study;
- Chapter 3 summarises and presents the results for each deliverable as well as an update on the gas market situation in 2022;
- Chapter 4 describes the challenges encountered and how they were overcome, and lessons learned from the project.

2 Summary of activities conducted

2.1 Meetings and main deliverables

The project was organised in seven main deliverables:

1. Inception report (**Deliverable 1**);
2. Baseline data collection report (**Deliverable 2**);
3. Report on the relevant scenarios for a decarbonised Baltic Regional Gas Market by 2050 (**Deliverable 3**);
4. Report on the impact assessment of the scenarios for a decarbonised Baltic Regional Gas Market (**Deliverable 4**);
5. Report on the risk analysis of the scenarios for a decarbonised Baltic Regional Gas Market (**Deliverable 5**);
6. Sensitivity analysis of the scenarios for a decarbonised Baltic Regional Gas Market (**Deliverable 6**);
7. Action plan for achieving a decarbonised Baltic Regional Gas Market (**Deliverable 7**).

The following table presents the meetings and key deliverable milestones.

Table 2-1 Summary of meetings and key milestones

Milestone	When
Contract start	11 February 2022
Kick-off meeting	17 March 2022
Deliverable 1: Inception report (Draft)	*28 March 2022*
Inception Meeting	5 April 2022
Deliverable 1: Inception report (Final)	**19 April 2022**
Deliverable 2: Stakeholder engagement workshop	19 April 2022
Intermediate meeting #1	29 April 2022
Progress meeting #1	18 May 2022
Deliverable 2: Baseline data collection report (Draft)	*31 May 2022*
Intermediate meeting #2	1 June 2022
Deliverable 3: Stakeholder engagement workshop	10 June 2022
Progress meeting #2	18 August 2022
Deliverable 2: Baseline data collection report (Final)	**20 September 2022**
Intermediate meeting #3	9 September 2022
Progress meeting #3	6 October 2022
Deliverable 3: Report on the relevant scenarios (Draft)	*24 November 2022*
Progress meeting #4	15 December 2022
Progress meeting #5	19 January 2023
Deliverable 3: Report on the relevant scenarios (Final)	**10 February 2023**
Progress meeting #6	16 February 2023
Deliverable 3: Report on the relevant scenarios (Final revised)	**5 April 2023**
Progress meeting #7	6 April 2023
Progress meeting #8	23 May 2023
Deliverable 4: Report on the impact assessment of scenarios (Draft)	*6 June 2023*
Progress meeting #9	27 June 2023
Deliverable 5: Report on the risk analysis of scenarios (Draft)	*27 June 2023*
Deliverable 6: Report on the sensitivity analysis of scenarios (Draft)	*4 July 2023*
Deliverable 7: Stakeholder consultation	4 July to 25 August
Deliverable 4: Report on the impact assessment of scenarios (Final)	**27 July 2023**
Deliverable 6: Report on the sensitivity analysis of scenarios (Final)	**27 July 2023**
Progress meeting #10	17 August 2023
Deliverable 5: Report on the risk analysis of scenarios (Final)	**31 August 2023**
Deliverable 7: Action plans (Final)	***12 September 2023***
Progress meeting #11	13 September 2023
Deliverable 8: Final report (Draft)	*8 October 2023*
Deliverable 8: Final stakeholder workshop (presentation at Gas Market Conference in Latvia)	3 October 2023
Progress meeting #12	18 October 2023
Deliverable 8: Final report (Final)	**28 November 2023**

Colour legend: meetings; deliverables (*draft*) (**final**); stakeholder consultations/engagement workshops

2.2 Monitoring indicators

Indicators for monitoring the project implementation

The monitoring of the project implementation employs the following indicators as reported throughout the course of the project, categorised according to the work completion status for each deliverable (%; **completed**/**in-progress**/**not started**).

Table 2-2 Project implementation monitoring indicators (including deliverable submission dates)

	% of work completed	1st output: Draft report	2nd output: Final report	Current status / Remarks
Deliverable 1: Inception report	**100%**	✓ 28 Mar 2022	✓ 19 Apr 2022	• Finalised
Deliverable 2: Baseline data collection report	**100%**	✓ 31 May 2022	✓ 20 Sep 2022	• Finalised
Deliverable 3: Report on relevant scenarios for a decarbonised gas market in Estonia by 2050	**100%**	✓ 24 Nov 2022	✓ 10 Feb 2023	• Finalised
Deliverable 4: Report on the impact assessment of scenarios for a decarbonised gas market in Estonia	**100%**	✓ 6 Jun 2023	✓ 27 Jul 2023	• Finalised
Deliverable 5: Report on the risk analysis of scenarios for a decarbonised gas market in Estonia	**100%**	✓ 27 Jun 2023	✓ 31 Aug 2023	• Finalised
Deliverable 6: Report on the sensitivity analysis of scenarios for a decarbonised gas market in Estonia	**100%**	✓ 4 Jul 2023	✓ 27 Jul 2023	• Finalised
Deliverable 7: Action Plans for achieving a carbon neutral gas market in Estonia	**100%**	N/A	✓ 12 Sep 2023	• Finalised
Deliverable 8: Final report	**100%**	✓ 9 Oct 2023	✓ 28 Nov 2023	• Finalised

Indicators for monitoring the study project's impacts

Following the project conclusion, indicators can be used to monitor its impacts. Our first approach to the indicators was presented in the inception report (Deliverable 1), and is hereafter updated.

We propose to use indicators for monitoring the project impacts according to the objective indicated in the ToR, which mentioned that the **main outcome should be proposals for new legislation/actions to be implemented for decarbonising the Estonian gas supply by 2050**. Based on the intended outcome, it would be appropriate to use **qualitative indicators** to measure the extent to which the recommended actions are endorsed/adopted/implemented in the four countries that are part of the Baltic regional gas market. This monitoring can in particular be set up for the proposed actions that focus on governance and legislation.

The project should also contribute to having positive long-term impacts such as:

- Increased deployment of renewable energy sources, in particular biogas/biomethane and renewable hydrogen;
- Reduction of consumption of fossil fuels;
- Increase of the security level of energy supply;
- Reduction of (fossil) energy import dependence;
- Maximising social and economic benefits.

We suggest **evaluating these impacts quantitatively by using the following monitoring indicators**:

- Consumption of natural gas (in GWh and share in overall final energy demand) per country to monitor the absolute and relative reduction in fossil gas consumption;
- Production of biogas per application (direct use for electricity and/or heat production - conversion to biomethane for injection in gas network – use of biomethane in transport sector) per country;
- Production of renewable hydrogen per application (direct use for industrial processes or in transport sector - injection in gas network) per country;
- Security of energy supply level: fossil gas imports from third countries (in GWh and €) per country to monitor the energy dependence;
- Direct employment in renewable gas sector per country.

3 Summary of project results

The main takeaways from deliverables 3 to 7 are described below. In section 3.1 'Updated gas market situation in 2022', the figures considered in Deliverable 2 have been updated to show the short-term impact of recent geopolitical events (i.e. Russian war in Ukraine and associated energy crisis) on the gas supply and use. In section 3.2, the latest developments regarding biomethane and biogas in the Baltic states and Finland is presented.

Box 1: Modelling assumptions disclaimer

The assumptions underpinning this project's modelling process were established in early 2022 through prior validated academic reports, other public data, internal brainstorming and comprehensive scrutiny by the project team, steering committee, and stakeholders. We have highly valued the stakeholder feedback and have duly taken into account all comments and concerns.

However, given the significant changes in the energy landscape since early 2022, it is important to acknowledge that some of the assumptions used for this study may no longer fully align with the current situation and expected developments. However, it is crucial to emphasise that the conclusions and recommended action plans of the study remain intact. This is primarily because the current substantially higher natural gas prices and the emergence of new supply constraints underscore the increasing importance of decarbonising the natural gas supply in the Baltic states and Finland common gas market for political, economic, energy and climate reasons.

While we have taken great care in crafting adequate scenarios and assumptions to properly encompass the project's scope and objectives, it is worth noting that continuous revisions based on the ever-evolving energy situation and outlook are not feasible. It is also essential to recognise that scenarios are not predictive tools but rather serve as a foundation for evaluating the potential impacts of various potential pathways and informing policy options.

Furthermore, we have factored in the dynamic nature of the gas market, especially in the aftermath of the Russia-Ukraine conflict and shifts in EU policies. This report provides a comprehensive explanation of our assumptions, including adaptations driven by feedback. Our projections are founded on best available data but do not predict future outcomes. Users are encouraged to interpret the findings with an awareness of inherent uncertainties, as considering such uncertainties is fundamental for informed decision-making.

3.1 Updated gas market situation in 2022

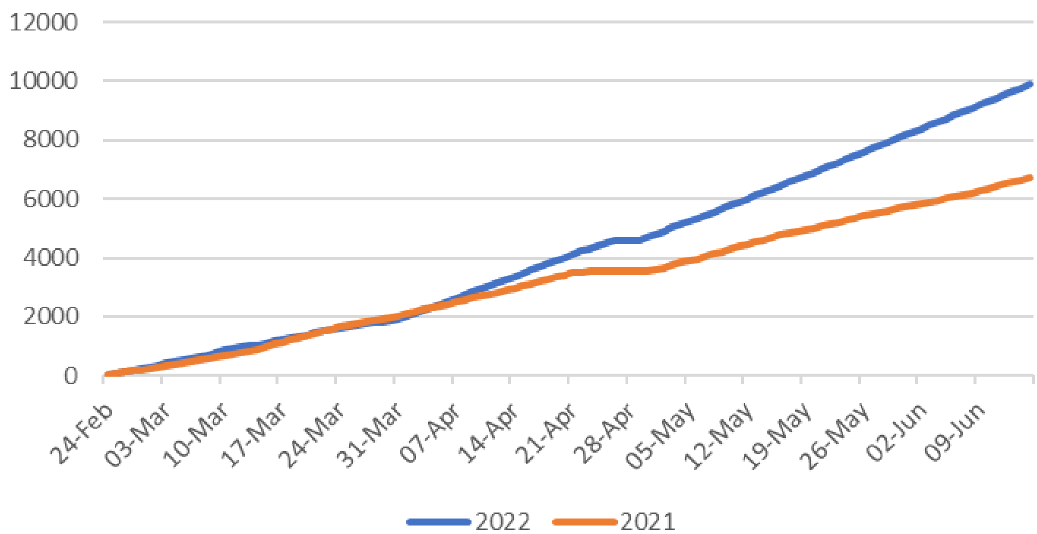
Recent developments in the Baltic-Finland natural gas market

Between August 2022 and January 2023, there was a notable decline in natural gas consumption in the EU, with a decrease of 19.3% compared to the average of the same months from 2017 to 2022. This decrease surpassed the target set by Council Regulation (EU) 2022/1369 of the REPowerEU plan, which aimed for a 15% reduction by March 2023.

Significantly, the Baltic countries recorded much higher reductions in their gas consumption. Lithuania saw a decrease of nearly 50%, Latvia 36%, and Estonia 32%, while Finland recorded a reduction of 57%, which was the highest in the whole EU. These drastic changes in gas demand in the Baltic countries and Finland came after they took initiatives to phase out gas supplies from Russia, following Russia's invasion of Ukraine in February 2022[3].

The overall gas demand in the Baltic states and Finland was in 2022 about 40% lower than in 2021; it fell from 66.7 TWh in 2021 to 40 TWh in 2022. Pipeline gas deliveries from Russia fell by 43%, while send-out volumes from the Klaipeda LNG terminal increased by 37%[4].

Figure 3-1 ***Cumulative LNG sendout from Klaipeda Feb-June 2021/2022.***[5]



Also Finland's reliance on Russian gas declined significantly, with the Balticconnector now serving as the primary gas supply route. Despite receiving Russian LNG via Novatek's Cryogas-Vysotsk facility, Gasgrid Finland considers these small-scale LNG terminals as off-grid, making their contribution to demand relatively minor[6]. Notably, the Baltic states and Finland have substantially reduced pipeline imports, with Finland's Gasum being cut off by Gazprom on 21st May 2022. This shift is remarkable, given that the region procured 76% of its gas from Russia in 2021[7].

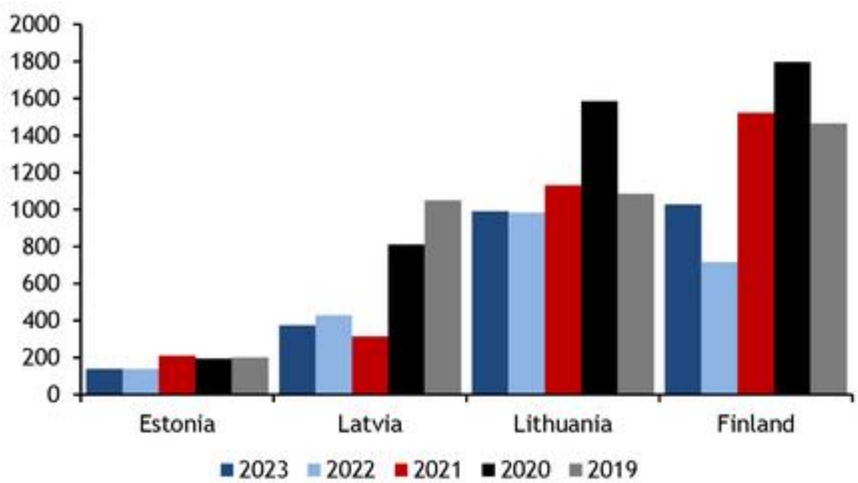
Lithuania ceased all imports of Russian gas for domestic use in April 2022, becoming the first country to ban Russian gas imports fully, in response to supply security concerns[8]. Achema, a major gas consumer in the Baltics, shifted to spot purchases of LNG to replace Russian pipeline gas. As a result, Russia's share in the region's gas supply mix decreased to less than 45%, accounting for 7.47TWh out of the total (16.66TWh) of Baltic imports, with Estonia also discontinuing direct Russian gas imports since March 2022, and since April 2022, virtually no natural gas has been imported from Russia to Estonia[9].

3 https://ec.europa.eu/eurostat/web/products-eurostat-news/w/DDN-20230221-1
4 Brendan A'Hearn, The Baltic gas market: a microcosm of Europe's struggle to quit Russian gas, OIES, September 2022. Available at: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2022/09/Insight-123-The-Baltic-gas-market.pdf
5 ibid
6 ibid
7 https://www.argusmedia.com/en/news/2345549-lithuania-bans-russian-gas-imports
8 https://www.argusmedia.com/en/news/2345549-lithuania-bans-russian-gas-imports
9 https://www.vm.ee/en/news/estonia-imposes-ban-natural-gas-imports-and-purchases-russia

Several factors contributed to the decline in gas demand, including high gas prices, increased use of alternative fuels, and shifts in the energy landscape[10]:

1. **High natural gas prices:** The rise in gas prices played a crucial role in the reduction of gas consumption. Gas consumers switched to less expensive energy alternatives, leading to a decrease in gas demand. The consumption decline continued until August 2023 when the combined Finnish and Baltic gas consumption was about 12% higher than in August 2022, a second consecutive month of year-on-year increase (see Figure 3-2). The overall consumption rose from 2.27 TWh in August 2022 to 2.53 TWh in August 2023. The higher Finnish demand was partly driven by increased gas-fired power generation. However, in the Baltic countries, gas-fired generation fell by roughly a quarter in both Latvia and Lithuania while remaining stable in Estonia[11].

Figure 3-2 Gas consumption in August by country (GWh). Source: Argusmedia



2. **Fuel switching in heating sector:** utilities and industrial facilities in the region, such as Estonian utilities Utilitas Tallinn and Enefit Power, applied for emissions exemptions to use fuel oil instead of natural gas for heating. In February 2023, gas consumption in the Baltic states (Estonia, Latvia, and Lithuania) experienced a decline of nearly 25% compared to February 2022, despite colder weather. Total consumption in these countries dropped from 3.3 TWh in February 2022 to 2.5 TWh in February 2023. This decrease reflects the reduced gas responsiveness to temperature changes, especially as some district heating firms switched to fuel oil during the winter.
3. **Reduced gas-fired power generation:** gas-fired power generation across the Baltic states and Finland decreased in 2022 by more than 50% compared to 2021. This decrease was due to a combination of factors, including increased wind and nuclear power generation. Finland saw for instance a 40% increase in wind energy generation and a 7% rise in nuclear power output. These emission-free energy sources contributed to reducing the need for gas-fired electricity generation.
4. **Industrial gas demand reduction:** industrial gas demand decreased significantly, especially in Lithuania, where ammonia producer Achema, a major gas consumer, idled its production or operated at reduced

[10] https://www.argusmedia.com/en/news/2417303-baltic-gas-consumption-down-by-40pc-in-2022
[11] https://www.argusmedia.com/en//news/2487461-baltic-and-finnish-gas-demand-continues-recovery-in-aug

rates during a significant portion of the year. This trend was also seen in other European countries where ammonia producers are located. Achema was in June 2023 still working below its nominal capacity. Some other major European ammonia producers, e.g., Billingham in the UK, preferred to close their plant and use imported ammonia instead but continued gas price volatility has made producers wary of lifting output[12].

5. **LNG replaces Russian gas:** Gazprom halted pipeline gas supplies in July 2022, citing vague contractual violations. In August 2022, Latvia briefly resumed importing Russian gas at Luhamaa due to contractual obligations but ceased shortly after, purchasing gas from an intermediary. Lithuania and Finland also banned Russian gas imports in 2022.

To cope with lower pipeline gas supplies from Russia, Lithuania's Klaipeda terminal significantly increased its send-out volumes, nearly doubling the previous year's levels. Finland's Inkoo LNG terminal also ensured an increasing share of the region's gas supply. This led to a significant shift in gas flows through the Balticconnector, redirecting towards Estonia for the first time since May 2022. Eesti Gaas has also been actively importing cargos from both the Inkoo and Klaipeda terminal[13].

In addition to the above LNG facilities, Estonia and Finland decided to install a joint FSRU in the Baltic Sea, the Exemplar. Such decision was not straightforward though. Under normal operating conditions, the FSRU would have an LNG send-out capacity of 140 GWh/d, but the Balticconnector's capacity limitations between Estonia and Finland restricted its full use. Regardless of the FSRU's location, the entry capacity to the transport network was limited to a range of 100-140 GWh/d. The FSRU primarily aimed to provide baseload supply and was unsuitable for peak load or long-term storage. If the FSRU was moored in Finland, its send-out capacity would mainly serve Finland's domestic consumption and the Balticconnector's capacity towards Estonia. This constraint was exacerbated by capacity limitations on the Balticconnector to Finland, making it challenging to meet peak demand, which was around 150 GWh/d.

Additionally, the region experienced a significant decline in gas demand due to factors such as a mild winter and the switch to alternative fuels, potentially reducing gas demand by up to 7 TWh. However, in October 2022, it was confirmed that the Exemplar FSRU would be moored in Finland's Inkoo port rather than in Estonia's Paldiski. This decision was based on supply security considerations and aimed to improve the regional energy supply security. To mitigate supply risks, the governments of Estonia and Finland agreed to develop rules that would allow gas suppliers guaranteed access to the terminal. Preferential access for Estonian and Finnish gas buyers was also discussed, but specific terms were still to be finalized.

Despite these challenges and the disappointment expressed by Estonian stakeholders, the deployment of the FSRU in Finland was seen as a step to enhance energy supply security for both countries. Discussions continued on potential solutions to ensure equitable access to the terminal, given its importance to the region's gas supply during an energy crisis. The possibility of acquiring an FSRU for Estonia was also explored to address these challenges.

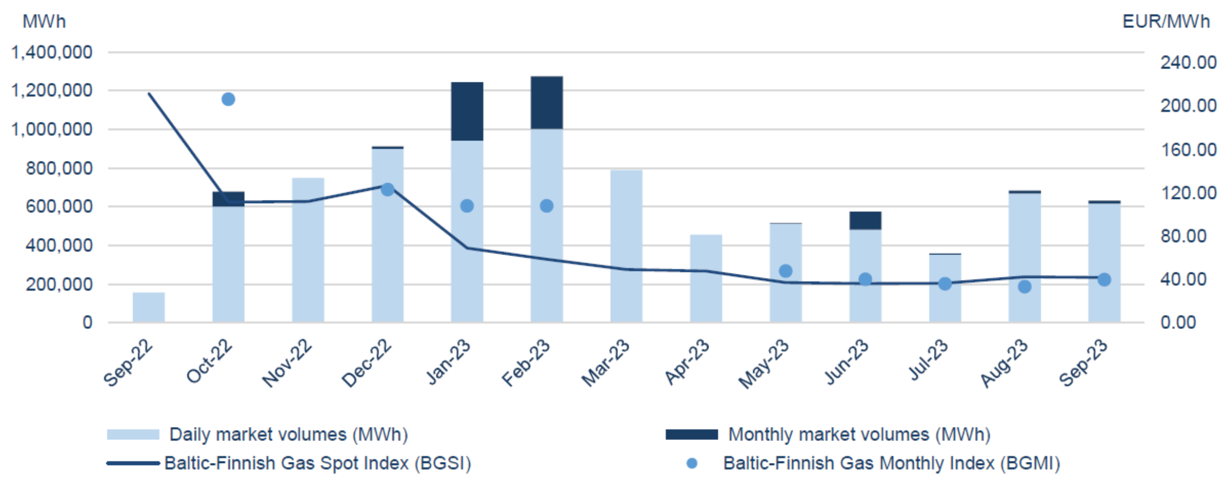
[12] https://www.argusmedia.com/en//news/2489755-eu-industrial-gas-demand-recovery-to-remain-slow
[13] https://www.argusmedia.com/en//news/2454325-eesti-gaas-to-import-seven-more-lng-cargoes-by-october

Overall, the deployment of the Exemplar FSRU between Estonia and Finland faced initial capacity challenges, but efforts were being undertaken to resolve them and enhance security of gas supply in the region.[14, 15]

Natural gas price dynamics since summer 2022

The first quarter of 2023 was one of the most active in the history of GET Baltic. The upward trend in the activity was influenced by a steady decrease in gas prices, with the average exchange price (BGSI) in March 2023 reaching 49.24 EUR/MWh, the lowest average price in the last 18 months. The average price on the GET Baltic exchange has fallen by 80% since August 2022, when the highest average price was recorded (241.69 EUR/MWh). The price decrease continued until September 2023, when the Baltic-Finnish Natural Gas Price Index (BGSI), which captures the changes in natural gas prices on the daily market, decreased by 1% month-on-month to 42.07 EUR/MWh. The Baltic-Finnish Gas Monthly Index (BGMI), which captures the changes in natural gas prices on the monthly market, stood at 40.00 EUR/MWh in September 2023. The decrease in the price of natural gas has been influenced by lower demand, high storage volumes and alternative supply sources, including increased LNG imports[16].

Figure 3-3 Monthly volumes and natural gas prices (VAT excluded). Source: getbaltic.com



Gas storage in Inčukalns

A significant initiative to respond to the energy supply crisis in 2022 has been the rapid transition to net injections at Latvia's Inčukalns storage site. Typically, withdrawals occur until early May, followed by replenishment in the summer. However, due to the regional gas supply security concerns, Conexus Baltic Grid, the gas storage operator, started the injections at the Inčukalns facility already end February 2022.[17] The Inčukalns facility is now operating continuously with a minimum injection capacity of 49.2 GWh/d until the end of the withdrawal season, with additional capacity adjusted daily. To make gas storage more cost-effective for users, Conexus also proposed regulatory changes. Additionally, Lithuania's operator, Amber

[14] https://www.argusmedia.com/en/news/2378964-baltic-fsru-to-moor-in-finland
[15] https://www.argusmedia.com/en/news/2380621-estonian-priority-access-to-finnish-fsru-unsure
[16] https://www.getbaltic.com/wp-content/uploads/Baltic-Finnish-Gas-Exchange-Trading-Report-September-2023.pdf and https://www.getbaltic.com/wp-content/uploads/Baltic-Finnish-Gas-Exchange-Trading-Report-March-2023.pdf
[17] Supra 1

Grid, chose to store gas in Inčukalns as part of its strategy to reduce the risk for potential delivery disruptions.

Latvia did not achieve the EU's target of filling its gas storage up to 80% by 1st November 2022. However, it exceeded the specific target of maintaining gas reserves at 35% of the annual consumption over the past five years. The storage level at Inčukalns stood at 13.8 TWh, out of a total capacity of just over 24 TWh, according to the latest data from the GIE transparency platform. Notably, Latvia was one of the four EU countries (next to Austria, Hungary, and Slovakia) that were exempted from the obligation to fill storages up to 80%. This exemption was granted due to their substantial storage capacity relative to their annual consumption. These countries were only required to maintain gas reserves at 35% of their average annual gas consumption over the past five years.[18,19]

Lithuania joining the FinEstLat regional gas zone

On January 1, 2020, Finland, Estonia, and Latvia established a shared gas market, eliminating tariffs between their respective national networks and implementing uniform fees at all border points. Grid operators from these three countries had been suggesting the inclusion of Lithuania in the FinEstLat regional zone as of 2023. This planned integration has however been delayed until at least October 2024 due to the new "geopolitical situation”, as revealed by the Finnish energy market regulator, Energiavirasto.

The new "geopolitical situation" has indeed led to significant shifts in the fundamentals of the regional market, presenting unprecedented challenges. Energiavirasto noted that the gas market is still turbulent, indicating that uncertainties persist. Given these substantial changes, the compensation mechanism previously agreed upon by the grid operators, which was developed based on earlier market assumptions, "no longer aligns with the current situation and may not be advantageous for all parties involved," according to the regulator.

Consequently, with the need for a comprehensive reform of the mechanism, the integration of Lithuania into the FinEstLat zone has been deferred until at least October 2024, as confirmed by Energiavirasto. Despite this postponement, efforts to integrate Lithuania will continue once the "market turbulence" subsides, and a more distinct understanding of regional market conditions is established, as stated by Energiavirasto[20].

Skulte LNG Terminal: From Promising Solution to Abandoned Project

In November 2022, plans for the Skulte LNG terminal in Latvia were announced, with construction set to commence in the second quarter of 2023. The project aimed to provide a cost-effective and flexible solution for LNG supply to the Baltic region, particularly Latvia and Estonia, which faced supply challenges due to limited cross-border transport capacity. The Skulte facility and connecting pipeline were estimated to cost around €120 million, significantly cheaper than alternative solutions like a floating storage and

[18] https://www.argusmedia.com/en/news/2386787-latvia-falls-short-of-eu-80pc-storage-ambition
[19] https://www.argusmedia.com/en/news/2306424-conexus-brings-forward-incukalns-injection-season
[20] https://www.konkurentsiamet.ee/en/news/postponement-finestlat-and-lithuanian-gas-market-merge

regasification unit (FSRU) in Finland. The terminal was planned to have a maximum send-out capacity of 200 GWh/d, and it was considered vital for Latvia's security of supply.

However, by February 2023, the project faced uncertainties as the Latvian government rejected a proposal for state support from the developer. Skulte LNG had sought guarantees to cover potential losses if the terminal were underutilised, but the government deemed the requested guarantees too high. Furthermore, doubts emerged about the necessity of the Skulte project as the gas consumption in the Baltic states and Finland had fallen significantly in 2022, and existing terminals seemed capable of meeting the regional gas demand. Additionally, long delays for delivery of equipment and an ongoing environmental impact assessment were expected to extend the terminal's completion date beyond the original deadline of September 2024.

As a result, in August 2023, the Latvian government decided to abandon the Skulte LNG project. The Energy Minister stated that the Inčukalns storage facility was well-filled, capacity was fully booked, and existing infrastructure would be able to ensure energy supply security for Latvia and the Baltic region. The government also pointed to the joint use of the Paldiski LNG terminal in Estonia as a viable alternative.

In conclusion, the Skulte LNG project, initially seen as a solution to regional gas supply challenges, faced numerous obstacles, including government's rejection of support and doubts about its necessity. Ultimately, it was abandoned in favour of other options.[21, 22, 23, 24]

3.2 Latest developments in biomethane/biogas in the Baltic and Finland region

Estonia

In Estonia, the developments in biomethane and biogas production and utilisation have shown notable changes in recent years. While biogas based electricity production decreased significantly in 2022 compared to 2021, with the output dropping to 7,073 MWh from the previous year's 16,974 MWh, the primary reason behind this decline is the conversion of several existing biogas plants into biomethane production units. This transition has been a consistent trend in recent years, contributing to the reduction in biogas based electricity production. Conversely, biomethane production has steadily increased. In 2022, Estonia had a production of 168,271 MWh of biomethane, sourced from various feedstocks including sewage sludge, animal manure, food industry waste, bio-waste, and another biomass. This substantial increase in biomethane production demonstrates Estonia's commitment to harnessing renewable energy sources and reducing its carbon footprint[25].

[21] https://www.argusmedia.com/en//news/2483972-latvian-government-abandons-skulte-lng-project?backToResults=true&utm_campaign=Oktopost-free-news-natural-gas-lng&utm_content=Oktopost-linkedin&utm_medium=social&utm_source=linkedin&utm_term=natural-gas-lng
[22] https://www.argusmedia.com/en/news/2438445-latvia-mulls-use-of-paldiski-lng-terminal
[23] https://www.argusmedia.com/en/news/2388434-skulte-lng-terminal-construction-to-start-in-2q23
[24] https://www.argusmedia.com/en/news/2422489-latvian-government-rejects-terms-for-skulte-lng
[25] http://eestibiogaas.ee/wp-content/uploads/2023/03/EBA-1_uudiskiri-jaanuar-marts_2023.pdf

Table 3-1 ***Electricity from Biogas Plants: Grid Injection and Installed Capacity (2014 - 2022)***

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Electricity produced from biogas and injected to grid (MWh)	42 843	49 796	44 874	41 754	37 355	38 082	29 391	16 974	7 073
Installed electrical total rated power (MWe)*	9,76	10,56*	10,56*	9,7*	9,35*	9,35*	9,35*	5,29*	5,29*

**Since 2015, EBA has taken into account the nominal capacity of the biogas plant of Tartu Vesi AS (0.3 MWe) when calculating the installed total electrical capacity of biogas plants, even though the said company does not supply electricity produced from biogas to the grid*

Currently, several Estonian companies are involved in biomethane production, including Rohegaas OÜ, Biometaan OÜ, Vinni Biogaas OÜ, Tartu Biogaas OÜ, Oisu Biogaas OÜ, Bioforce OÜ Aravete, and EKT Ecobio OÜ. A study conducted by the Estonian University of Life Sciences (EMÜ) revealed significant untapped potential for additional biogas/biomethane production. A substantial amount of biodegradable waste from various sectors, such as agriculture, food, and beverage industries, is still being discarded. This waste could support the operation of 5.2 biogas digesters in Põlva County, 2.9 in Valga County, and 1.1 in Võru County, each with a capacity of 4,000 cubic meters, providing a steady supply of biogas. Moreover, the study indicates that northern Võrumaa could benefit from a second biogas plant. Furthermore, crop production by-products like straw are often left in the fields, and biodegradable waste from the food and drink industry could also be recycled. Currently, these waste materials are mostly sent to waste treatment facilities, but approximately 55% of surveyed companies express their willingness to collaborate more closely with other businesses for by-product processing[26]. The latest production levels of biomethane are indicated in Table 3-2.

Table 3-2 Biomethane production in Estonia in 2018-2022

Biomethane production	2018	2019	2020	2021	2022
Total, MWh	39 993	63 080	97 408	152 352	168 271

In Viljandimaa, there are plans to bolster the production and utilisation of biomethane, with the construction of a cutting-edge biomethane plant set to be completed by the end of 2025. This project represents an investment of approximately 25 million euros, aiming to reduce the environmental concerns associated with waste management. The plant's objective is to convert various waste streams, including sewage sludge, liquid manure from the largest pig farm in Ekseko, and waste from the Rakvere meat industry, the Talleggi factory, and poultry farms, into biomethane and valuable fertilisers. It is expected that the annual production of biomethane will be in the range of 7-8 million cubic meters (m3)[27]. Additionally, the ambition of powering Tallinn's city buses with green gas is on the horizon, with 150 out of 350 gas buses in Tallinn expected to run on biomethane once the above mentioned biomethane plant reaches full capacity.

[26] https://news.err.ee/1608858038/significant-potential-for-biogas-production-in-estonia-remains-untapped
[27] https://forte.delfi.ee/artikkel/120213892/viljandimaale-rajatakse-eesti-suurim-biometaanijaam

In order to achieve the renewable energy target of at least 65% of the total domestic final energy consumption by 2030, the government has decided to extend the subsidies for the production of biomethane used in the transport sector until June 30, 2024. Initially, the biomethane subsidies were scheduled to expire at the end of 2023. However, to reach the increased renewable energy goals, the support has been extended. The revenue generated from the sale of CO_2 quotas will contribute an additional €11.8 million to support the development of biomethane. Under this initiative, the government grants a subsidy of €100 minus the average market price of natural gas per MWh of biomethane supplied to the transport sector. If the market price of gas exceeds 100 €/MWh, no subsidy is disbursed. Since 2018, Elering has been responsible for providing biomethane subsidies to producers based on the quantity of biomethane produced and consumed. Up until 2022, these payouts have amounted to a total of €25.3 million[28].

Latvia

In 2021, the biogas consumption in combined heat and power stations (CHP) reached 687 GWh. While there is a growing interest in upgrading biogas to biomethane, precise figures are not available. In 2021, Latvia had 47 operational biogas stations under the mandatory procurement (OI) system, with a collective installed electric capacity of 55.9 MW and electricity production of 213 GWh. However, by January 1, 2022, this number had decreased to 40 plants with an overall electric capacity of 44.6 MW. Unfortunately, records of biogas plants leaving the OI system are no longer maintained. Two cogeneration plants utilising biogas operated outside the OI system in 2021[29].

In December 2022, the Ministry of Economy introduced amendments to the Energy Law, including provisions for biomethane proof of origin certification. The new government is planning investment support for biomethane production. This includes acquiring compressors for biomethane injection into natural gas networks and transportation, funded by EU resources in the upcoming period[30].

Latvia is actively developing centralized biomethane injection points to enhance the distribution of biomethane, with Conexus planning four such injection points. The injection point locations will align with regions of stable biogas production. State aid mechanisms, such as tax reductions and grants, are under consideration to incentivise biogas plants to transition to biomethane production[31].

Lithuania

In August 2022, Lithuania's Ministry of Energy announced plans to allocate 22.2 million euros to support the production of biomethane. The focus of this initiative is on utilising biomethane within the transport sector and large natural gas consumers. The Ministry outlined a goal to produce yearly at least 950 GWh of biomethane by 2030.[32]

In September 2023, Lithuania announced the commissioning of its first biomethane plant. Situated in the Pasvalys District, the Tube Green plant will generate 100 GWh of biomethane annually, thus covering

[28] https://news.err.ee/1608839272/state-continues-to-subsidize-biomethane-production
[29] https://interreg-baltic.eu/wp-content/uploads/2023/04/Best-Ace-State-of-play-Final-Version.pdf
[30] Supra 29
[31] https://eng.lsm.lv/article/economy/economy/24.03.2023-conexus-plans-biomethane-infrastructure-in-latvia.a502184/
[32] https://ceenergynews.com/renewables/lithuania-to-allocate-over-22-million-euros-for-biomethane-projects/

approximately 1% of the nation's total gas demand. Tube Green is collaborating on this project with local biofuel producer Kurana, and they have invested €15 million into the venture The European Climate Change Programme has allocated €2.8 million to support the plant[33].

Finland

As per the Roadmap to Fossil-Free Transport, Finland is actively promoting the use of biomethane in the transport sector. The roadmap outlines Finland's capacity to support an annual biogas production of 16 TWh, with specific targets of utilizing 2.5 TWh of biomethane in transport by 2030 and 5-6 TWh by 2045. This would potentially power 100,000-130,000 passenger vehicles and 6,000 heavy-duty vehicles with 100% biomethane, out of a total vehicle count of approximately 3.2 million in Finland in 2021. To support the increased use of biomethane in transportation, Finland has incorporated biomethane into the biofuel mandate and offers investment aid to agricultural and rural enterprises involved in biomethane projects. Notably, the Energy Aid programme allocated EUR 40.2 million to projects related to biomethane in transport from 2018 to 2021. Finland's government is committed to closely monitoring the biogas sector's progress and taking necessary actions to ensure its rapid and sustainable growth[34]

Moreover, the Finnish state-owned energy company Gasum Oy is shifting its focus towards renewable gas and electricity as part of its new five-year strategy. Gasum has set an ambitious goal to increase its supply of biogas in the Nordic region from 1.7 TWh in 2022 to 7 TWh in 2027. Gasum currently operates 17 plants in Finland and Sweden, extracting biogas from various waste sources, including sewage sludge, manure, and biowaste.[35].

Lastly, the decision on the location of the Suomen Lantakaasu Oy Biogas Plant in Finland was released in August 2023. Construction preparations are now advancing for this biogas production facility of Suomen Lantakaasu Oy, a partnership between Valio, a food company, and St1, an energy company. The biogas plant will produce liquefied biogas from cattle farms' manure and other agricultural by-products in Upper Savo. The completion of the plant is scheduled for 2026[36].

3.3 Relevant scenarios for a decarbonised Baltic Regional Gas Market by 2050 (Deliverable 3)

The objectives of Deliverable 3 were to define and analyse the potential routes to decarbonise the Baltic Regional Gas Market by 2050. In this context, the study team has developed a **Business-as-usual (BAU) scenario** as well as three gas decarbonisation scenarios:

- ✓ **Renewable methane (REN-Methane) scenario**, leveraging biogas and biomethane for on- and off-grid applications, reserving hydrogen for off-grid hard-to-decarbonise applications;
- ✓ **Renewable hydrogen (REN-Hydrogen) scenario**, with on- and off-grid use of hydrogen and development of a regional cross-border hydrogen network by 2050;

[33] https://www.bioenergy-news.com/news/lithuanias-first-biomethane-plant-is-now-operational/).
[34] https://iea.blob.core.windows.net/assets/842c42c2-8d79-4845-92c8-d36c0ff96ef4/Finland2023-EnergyPolicyReview.pdf
[35] https://renewablesnow.com/news/finlands-gasum-targets-7-twh-of-rng-annually-by-2027-819904/
[36] https://www.st1.com/decision-on-location-of-suomen-lantakaasu-oy-biogas-plant-in-finland

- ✓ **Cost Minimal scenario (CM)**, exploring competition between renewable gases and natural gas, to find the least cost based decarbonisation solution for the modelled period, given set constraints and modelling boundaries.

The following table and descriptions give an overview of the scenarios.

Scenario 1: Business-as-usual scenario (BAU)
In this scenario, no new climate change mitigation efforts are initiated for the RGMCG region. The existing National energy and climate plans guide the development. The BAU scenario envisions a continuous reliance on Natural Gas (NG) till 2050, supplemented later by biomethane and hydrogen. Gas demand projections are derived from various national sources and are complemented by country-specific gas production targets. The gas transport infrastructure remains largely unchanged, considering the existing pipelines and interconnectors. Notably, gas from Russia and Belarus ceased after mid-2022. Existing LNG terminal capacities are taken into account with potential expansion based on model optimisation. However, the objective of achieving a climate-neutral gas supply by 2050 is not met in this scenario.

Scenario 2: Renewable Methane scenario (REN-Methane)
This scenario aims to achieve a carbon-neutral gas supply by 2050. Gas demands are met primarily through biomethane, followed by hydrogen and Synthetic Natural Gas (SNG). Baseline gas demands are adjusted to account for electrification effects. Biomethane production targets are set based on each country's feasible potential, and biomethane becomes the primary gas injected into the distribution and transport gas systems. The hydrogen limit in the transport network is increased to 10% by 2050. The infrastructure, including LNG terminal capacities and gas transport networks, remains similar to the BAU scenario. However, this scenario successfully achieves a climate-neutral gas supply by 2050.

Scenario 3: Renewable Hydrogen scenario (REN-Hydrogen)
The REN-Hydrogen scenario also targets carbon neutrality by 2050 but shifts its focus towards renewable hydrogen. After 2040, renewable hydrogen is expected to dominate gas demands in the gas on-network (100%) and off-network, assuming biomethane will be injected off-network after 2040. Gas demands are recalibrated to account for the electrification impacts, similar to the REN-Methane scenario. The hydrogen ceiling in the transport network rises to 10% by 2040, after which it will occupy the entire 100% gas network. NG is phased out gradually until 2040, with no synthetic natural gas additions. The infrastructure for gas transport and LNG terminals aligns with the prior scenarios, and carbon neutrality is accomplished by 2050.

Scenario 4: Cost Minimal scenario
Prioritising cost-effectiveness, this scenario seeks carbon neutrality by 2050. The gas mix comprising biomethane, hydrogen, SNG, and NG, is optimised for least-cost solutions. The baseline gas demands are updated analogously to the REN scenarios, and biomethane production is capped at each country's maximum feasible potential. Biomethane and hydrogen storage capacities are expanded based on model optimisation. Gas transport infrastructure retains the characteristics of the earlier scenarios, with LNG imports ceasing after 2040. This scenario, while focusing on cost minimisation, also attains a climate-neutral gas supply by 2050.

Table 3-3 presents the qualitative comparison between the BAU and gas decarbonisation scenarios (REN-Methane, REN-Hydrogen and Cost Minimal). Table 3-3 presents an overview of the main quantitative indicators for 2030 and 2050, while Figure 3-4 depicts the gas supply under each scenario.

Table 3-3 Overview of the scenario definitions (qualitative comparison of the explored scenarios for the Baltic+Finland joint gas market)

<table>
<tr><th rowspan="2">Indicators</th><th>Scenario 1</th><th>Scenario 2</th><th>Scenario 3</th><th>Scenario 4</th></tr>
<tr><th>'Business-as-usual'</th><th>'REN-Methane dominant scenario'</th><th>'REN-Hydrogen dominant scenario'</th><th>'Cost minimal scenario'</th></tr>
<tr><td>Decarbonisation level</td><td>Non-Climate neutral scenario (Joint gas market is not decarbonised by 2050)</td><td colspan="3">Climate-neutral scenarios (Gas sector is decarbonised by 2050)</td></tr>
<tr><td colspan="5">End-user decisions</td></tr>
<tr><td>End-user decisions regarding the applications in demand sectors</td><td>Focus on methane-based end-user applications</td><td>Focus on methane-based end-user applications</td><td>Focus on hydrogen-based end-user applications</td><td rowspan="2">Focus on the least cost-based fuel mix (with the hydrogen technical limitation constraints without significant investment for retrofitting)</td></tr>
<tr><td>Major gas carrier</td><td>NG is still a major part of the gas demand (followed by biomethane and hydrogen and a small portion of biogas)</td><td>Methane (includes biomethane and SNG and followed by H_2 and a small portion of biogas)</td><td>Hydrogen (followed by a small portion of biomethane and biogas)</td></tr>
<tr><td colspan="5">Strategy for the gas infrastructure to follow end-user decisions</td></tr>
<tr><td>Gas type expected within a national and cross-border gas infrastructure</td><td>NG followed by biomethane and hydrogen</td><td>Short term: NG followed by biomethane, SNG, and hydrogen
Long-term: Biomethane followed by SNG and hydrogen</td><td>Short term: NG followed by hydrogen
Long term: NG followed by hydrogen and eventually pure hydrogen</td><td rowspan="2">Optimised scenario for the least cost solution (with the hydrogen technical limitation constraints without significant investment for retrofitting)</td></tr>
<tr><td>Hydrogen blending</td><td>Up to 5 vol.%</td><td>Up to 10 vol.%</td><td>Up to 10 vol.%
and eventually 100 vol.% pure hydrogen</td></tr>
<tr><td>Natural gas infrastructure</td><td>No retrofitting of gas supply infrastructure is envisioned</td><td>No heavy retrofitting on gas supply infrastructure is envisioned
Technical possibilities of biomethane and hydrogen injection in transport and/or distribution pipelines are considered.</td><td>No heavy retrofitting on gas supply infrastructure is envisioned for blending levels up to 10 vol.%
The total repurposing/replacement of NG network infrastructure (TSO and DSO pipelines) is envisioned separately to provide an insight to the stakeholders and it is not included in the investment calculations.[37]</td><td>Retrofitting constraints (on the NG network infrastructure) are envisioned if the hydrogen blending levels cross the threshold of 10 vol.%</td></tr>
<tr><td>End-user equipment adaptation</td><td>No retrofitting constraints for end-use applications are considered except for the applications where the end equipment is sensitive to the NG gas quality.</td><td>Retrofitting constraints for end-use specific applications.</td><td>Retrofitting or replacement constraints for end-use-specific applications.</td><td>Retrofitting constraints for end-use specific applications.</td></tr>
<tr><td>Gas supply infrastructure in use</td><td>The role of transport pipelines remains largely intact. Gas distribution via DSO pipelines.</td><td>The role of transport pipelines remains largely intact. Gas distribution via DSO pipelines.</td><td>The role of transport pipelines remains largely intact. Gas distribution via DSO pipelines.</td><td>The role of transport pipelines remains largely intact. Gas distribution via DSO pipelines.</td></tr>
</table>

[37] 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.

<table>
<tr><th rowspan="2">Indicators</th><th>Scenario 1</th><th>Scenario 2</th><th>Scenario 3</th><th>Scenario 4</th></tr>
<tr><th>‘Business-as-usual’</th><th>‘REN-Methane dominant scenario’</th><th>‘REN-Hydrogen dominant scenario’</th><th>‘Cost minimal scenario’</th></tr>
<tr><td>Deployment of dedicated gas pipelines by TSO and/or DSO</td><td colspan="4">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)</td></tr>
<tr><td>Change of demand between scenarios</td><td>Baseline demand projections</td><td colspan="3">Gas demand projections with electrification considerations</td></tr>
<tr><td>Gas storage</td><td colspan="2">Conventional large-scale underground methane storage with an assumption to be able to store blended gas up to 10 vol.% H_2[38]</td><td>Conventional large-scale underground methane storage with an assumption to be able to store blended gas up to 10 vol.% H_2 blends and pure H_2 after 2040.</td><td>Conventional large-scale underground methane storage with an assumption to be able to store blended gas up to 10 vol.% H_2 blends</td></tr>
</table>

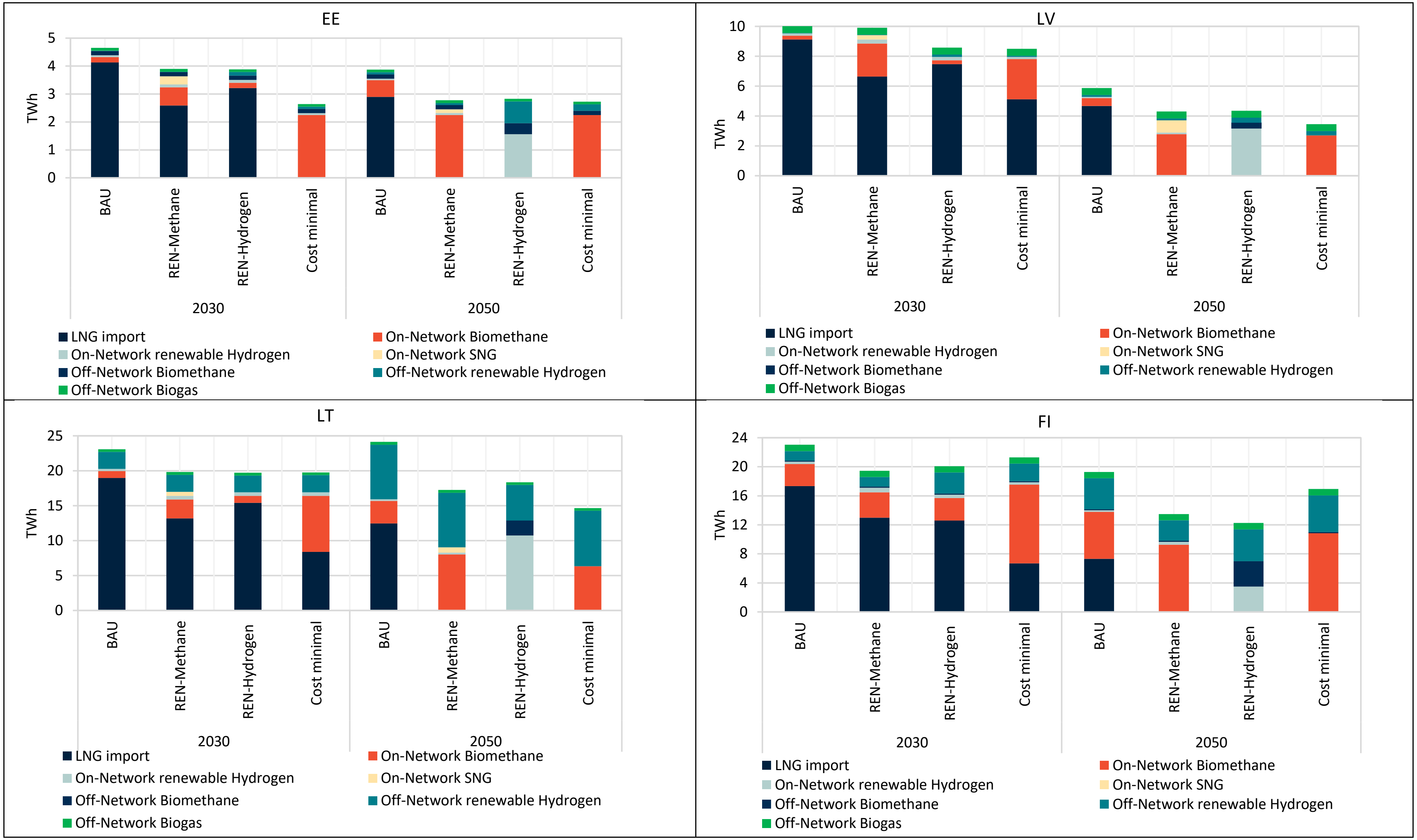
[38] This assumption has been taken by considering the ongoing feasibility study on UGS in Latvia.

Table 3-4 Summary of BAU and gas decarbonisation scenarios for the Baltic+Finland region

		BAU		Biomethane		Hydrogen		Cost Minimal	
	Unit	2030	2050	2030	2050	2030	2050	2030	2050
Supply	**TWh**	60.79	53.15	53.10	37.80	52.22	37.80	52.21	37.77
LNG imports	TWh	49.56	27.33	35.38	0.00	38.63	0.00	16.53	0.00
Biomethane (of which on-grid)	TWh	4.78 (4.47)	11.14 (10.83)	9.38 (9.07)	22.59 (22.28)	4.83 (4.52)	6.40 (0.00)	24.10 (23.79)	22.42 (22.11)
Hydrogen (off which on-grid)	TWh	4.62 (0.82)	12.85 (0.58)	5.33 (1.53)	11.66 (0.86)	6.93 (1.33)	29.57 (18.93)	6.42 (1.39)	13.52 (0.00)
SNG on-grid	TWh	0.00	0.00	1.18	1.72	0.00	0.00	3.33	0.00
Biogas off-grid	TWh	1.83	1.83	1.83	1.83	1.83	1.83	1.83	1.83
Gas production installed capacity	**GW**	2.99	7.95	3.98	9.38	4.08	15.20	7.22	11.38
Biomethane	GW	0.70	1.56	1.33	3.12	0.70	1.04	3.29	3.29
Electrolytic hydrogen	GW	2.05	6.14	2.28	5.62	3.14	13.91	2.90	7.06
SNG	GW	0.00	0.00	0.37	0.64	0.00	0.00	1.03	1.03
Biogas	GW	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
Renewable electricity needs for gas production	**TWh**	6.80	17.30	10.00	18.60	10.20	39.90	8.90	18.20
Storage capacity	**-**	-	-	-	-	-	-	-	-
Methane gases	TWh	12.24	12.53	12.33	10.65	12.24	12.17	12.24	10.77
Hydrogen	TWh	0.15	0.15	0.15	0.15	0.29	0.29	0.23	0.23
LNG terminal capacities	**TWh/y**	164	112	163	86	163	82	158	67
Average LCOE	**-**	-	-	-	-	-	-	-	-
Natural gas with ETS	EUR/MWh	113	138	113	138	113	138	113	138
Biomethane	EUR/MWh	77	55	71	52	82	57	65	53
Hydrogen	EUR/MWh	269	102	264	101	266	96	224	121
Average yearly cost to consumers	**-**	-	-	-	-	-	-	-	-
Households	EUR/y	666	496	760	265	675	402	677	229
Commercial users	EUR/y	13 651	10 184	15 611	5 427	13 844	8 234	13 900	4 667
GHG emissions	**Million ton CO2eq**	8.94	5.09	6.32	0.18	6.73	0.38	2.73	0.18

Source: SEI (2023) Gas Decarbonisation Pathways for Estonia - Deliverable 3: Report on relevant scenarios for a decarbonised gas market in Estonia by 2050

Figure 3-4 Gas supply of the Baltic+Finland region



Source: SEI (2023) Gas Decarbonisation Pathways for Estonia - Deliverable 3: Report on relevant scenarios for a decarbonised gas market in Estonia by 2050

Highlights of scenario modelling results for the RGMCG region

The RGMCG project's scenario modelling revealed varied gas supply solutions for the countries within the region. All four countries (3B+F) are interconnected through transport pipelines, enabling the transportation of imported LNG and other gases from one nation to another. The detailed scenario results are presented in the D3 report.

1. Gas Supply

BAU Scenario: A pronounced dependency on LNG imports is predicted for all countries by 2030 and 2050. Estonia and Latvia exhibit the highest reliance, primarily due to their lower domestic renewable gas production levels in 2030.

Methane Scenario: By 2050, the chief focus is to maximize biogas/biomethane production. The primary gas supply sources will become biogas/biomethane and Synthetic Natural Gas (SNG), with SNG filling the demand gaps based on each country's biogas/biomethane availability.

REN-Hydrogen Scenario: By 2040, all countries will be dependent on LNG imports with a gradual shift to renewable gases. However, a shift is anticipated by 2041, where pipelines will exclusively supply renewable hydrogen, and the biomethane used for pipeline blending before 2040 will shift to off-network sources.

Cost Minimal Scenario: By 2030, countries are anticipated to produce their peak biomethane potential, continuing till 2050. The subsequent decade (2030-2040) will lean on the existing and upcoming LNG terminals to address the NG demand-supply balance. By 2040, a shift towards 100% decarbonized supply is expected due to the injection of renewable gases.

2. Renewable Electricity

Renewable electricity is crucial for renewable hydrogen and SNG production. By 2050, in the REN-Hydrogen scenario, Estonia, Latvia, and Finland will lead the demand charts, requiring 3.2 TWh, 4.7 TWh, and 10.6 TWh, respectively. On the other hand, Lithuania will dominate the demand in the cost-minimal scenario.

Assessing these requirements, the project also projected the equivalent size of renewable electricity production capacities for each country by 2050. The determinants here are whether the electricity is derived from on-shore or off-shore wind energy plants, given the differing load factors. For instance, under the REN-Hydrogen scenario, Estonia might need up to 0.859 GW off-shore wind energy capacity, while Lithuania might require a massive 5.4 GW.

In essence, the RGMCG region's future energy landscape is set to experience significant transformations. These will pivot around the intricate balance between LNG imports, renewable gas production, and the accompanying renewable electricity requirements.

3. Gas Flows

BAU Scenario: A slight reduction in gas flow volume is expected by 2050 due to falling overall gas demand and the influence of domestic gas production.

REN-Methane Scenario: While external import dependency will decrease by 2050, internal gas flow between the countries will surge, primarily due to varying production profiles.

REN-Hydrogen Scenario: External LNG dependency will vanish by 2040, with renewable hydrogen constituting 100% of pipeline gas by 2041.

Cost Minimal Scenario: 2030 will see minimal gas flow among countries due to existing/planned LNG terminals. By 2050, Lithuania will majorly import gas, relying on Finland's excess biomethane production.

4. Gas storage

Latvia's underground gas storage is the only underground gas storage system which serves the Baltic Finnish region. In most scenarios, there is limited to no utilization of this storage in 2050, except in the Cost Minimal scenario where it sees significant usage in 2040 and 2050. The feasibility of storing blended hydrogen gas or pure hydrogen in Latvian UGS is yet to be determined. No off-network storage requirement exists for biomethane. However, off-network renewable hydrogen storage is essential, especially for Lithuania and Finland, due to their high industrial hydrogen demand.

5. Levelised Cost of Production

Biomethane: By 2050, biomethane emerges as the most economically produced gas. Latvia has the region's lowest production costs, given its exclusive reliance on biowaste as a feedstock.

Renewable Hydrogen: Its production cost will have a dramatic decrease from 2030 to 2050, attributed to technology advancements and efficiency improvements.

Overall Implication: The scenarios REN-Methane and REN-Hydrogen suggest a long-term decarbonization roadmap for the Baltic Finnish region, emphasizing self-sufficiency. In contrast, the Cost Minimal scenario offers a swift decarbonization solution, maximizing biomethane capacity deployment by 2030.

In summary, the region's future energy landscape is anticipated to undergo significant shifts, primarily characterized by internal gas flow patterns, strategic storage utilization, and declining renewable gas production costs.

6. Regional LNG capacities

LNG Capacity Roles: Country-specific LNG capacities play different roles across scenarios, serving as potential solutions for energy crisis mitigation, especially concerning the cessation of gas imports from Russia.

BAU Scenario: Even as natural gas (NG) demand reduces over the years, the RGMCG countries will continue to be significantly dependent on LNG. The model anticipates varied LNG terminal capacities for Estonia, Finland, and Lithuania across different time frames from 2030 to 2050. Expert analysis suggests that these additional capacities might not be necessary. The gradual decrease in NG demand across scenarios permits the utilization of the existing Klaipeda LNG terminal till 2044 and the planned Skulte terminal in Latvia up to 2050.

Booking System: To manage NG demand and supply efficiently, any country in the region can reserve their LNG capacities/cargo quantities in the RGMCG region's existing or planned terminals.

LNG Capacities in 2050: A cross-scenario comparison reveals that assuming the continued operation of the Klaipeda LNG terminal (up to 2044) and the planned Skulte LNG terminal (up to 2050), there would be sufficient capacity flexibility to manage the region's NG demand. Renewing the Finnish FSRU lease post-2033 might be redundant since the goal is to transition to carbon-neutral gas by 2040 or 2050, depending on the scenario.

Decarbonisation & Repurposing: While all scenarios, except BAU, aim for full decarbonization by 2050, its projected there will be no fossil LNG imports by 2050 in the fully decarbonized scenarios. However, any remaining LNG terminal capacities can be re-purposed and used for potential imports/exports of liquid hydrogen or other hydrogen-derived energy carriers like methanol or ammonia.

The Deliverable 3 scenario modelling for the RGMCG region was completed at the end of 2022 and the final D3 report was submitted on Feb 10, 2023. The assumptions considered in the modelling are based on 2021 and 2022’s existing data. In 2022, the Skulte LNG terminal in Latvia was designated an "object of national interest." However, by April 11, 2023, the Latvian government, guided by an analysis from its Ministry of Climate and Energy, concluded that the region already had adequate LNG import capacity and that a commercially viable LNG terminal was not feasible. This decision was further reinforced by environmental NGOs like Bankwatch, viewing the project's cessation as an end to a fossil fuel endeavour. This shift highlights the growing emphasis on environmental sustainability and the challenges fossil fuel projects face in today's climate-conscious era[39]. Even though the modelling included Skulte as a planned LNG terminal for the region, this topic was analysed in the risk analysis.

In essence, the RGMCG region's future reliance on LNG terminal capacities will pivot based on the prevailing scenario, with the potential for repurposing them to accommodate future energy demands and environmental goals.

3.4 Impact assessment of the scenarios for a decarbonised Baltic Regional Gas Market (Deliverable 4)

Deliverable 4 assessed the impact of the BAU and gas decarbonisation scenarios, from the perspective of:

- **Energy system impacts**, in particular in terms of their impacts on the gas system, on greenhouse gas emissions, and on energy costs for consumers;
- **Macro-economic impacts**, in particular in terms of GDP and employment.

Overall gas system and renewable electricity generation costs

The figures below present the expenditures of the modelled system (gas system and renewable electricity generation for electrolysis). Figure 3-5 presents the total system costs disaggregated between CAPEX and OPEX, while Figure 3-6 presents the detailed CAPEX broken down by application/technology. The costs presented are the cumulative discounted costs for each of the relevant study periods (2022-2030, 2031-2040, 2041-2050).

[39] https://emerging-europe.com/news/as-latvia-cancels-skulte-lng-project-the-baltic-reliance-on-gas-persists/

The major reason for the lower cost levels in all decarbonisation scenarios is the substitution of LNG purchases by less expensive domestic renewable gas production. Thus, OPEX savings are the main benefits of the decarbonisation scenarios. The substitution of LNG imports requires significant investments in domestic renewable gas production, but these are offset by lower investments in LNG import terminals, meaning that the overall CAPEX levels are similar for all scenarios (BAU and decarbonisation scenarios), ranging between 10.8 billion EUR in the Cost Minimal scenario and 11.3 billion EUR in the BAU scenario to.

All scenarios have a similar OPEX to total expenditures ratio, with OPEX representing 92 to 94% of total expenditures, with the exception of the Cost Minimal scenario where the ratio amounts to 89%. This lower ratio is due to the fact that the Cost Minimal scenario is able to reduce LNG imports to a greater extent and more quickly, and thus has lower associated OPEX. The modelling results show indeed that the Cost Minimal scenario is able to reduce total costs already in the 2022-2030 period, which is due to significant investment being made already in that period to substitute LNG imports by renewable gases.

Figure 3-5 Total costs (CAPEX + OPEX) for the gas system and renewable electricity generation for electrolysis for the study scenarios

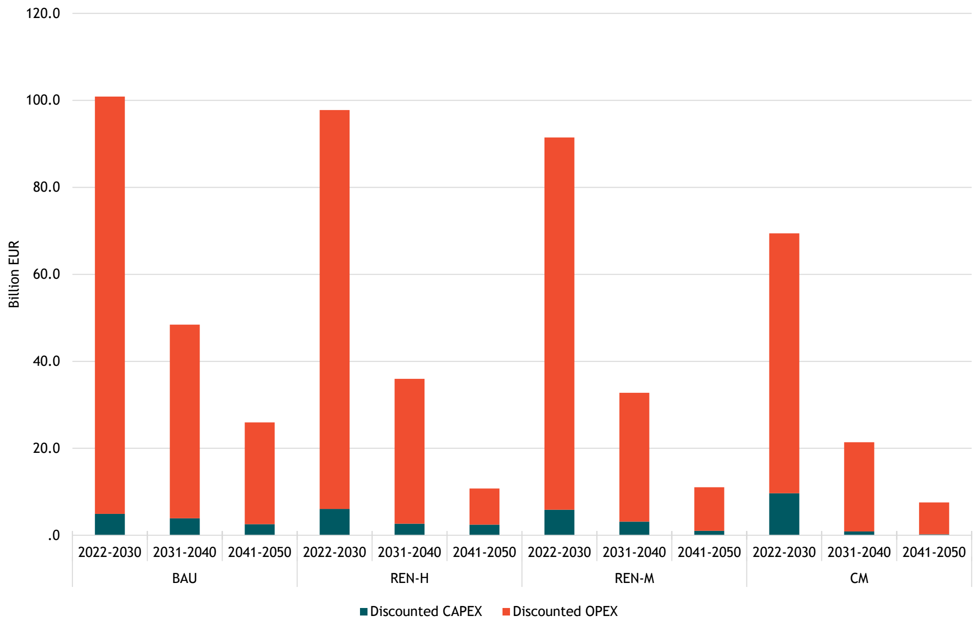
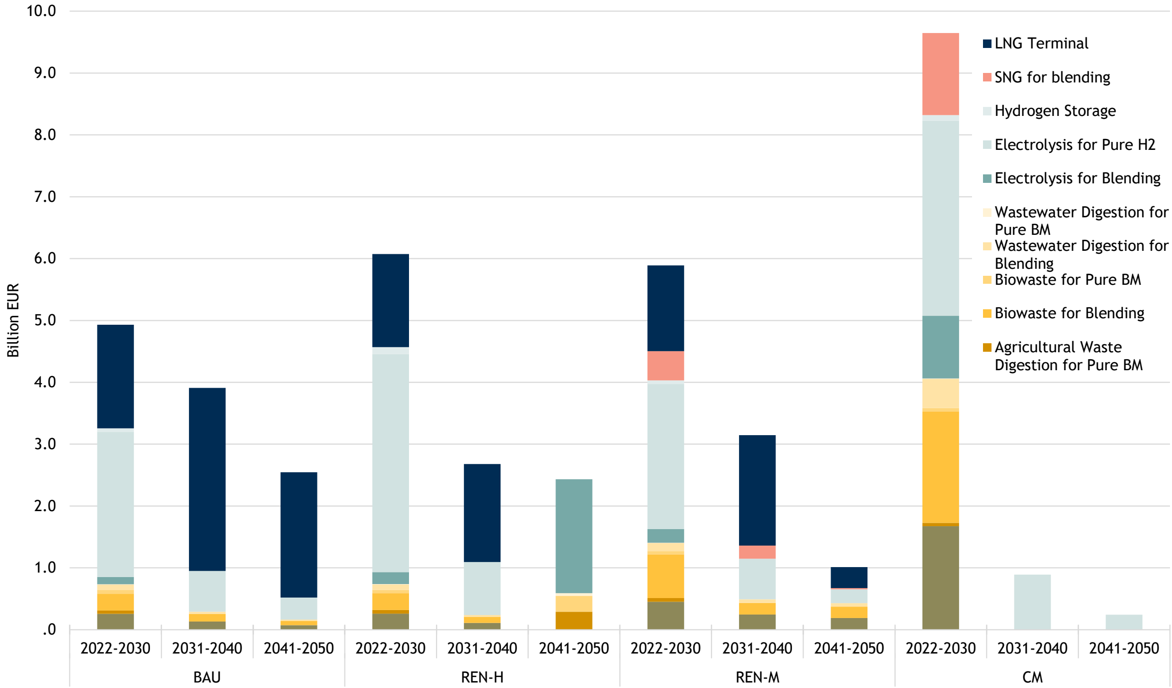


Figure 3-6 CAPEX for the gas system and renewable electricity generation for electrolysis for the study scenarios



In addition to the costs above, deliverable 3 has analysed the costs for repurposing of natural gas networks (which would be applicable for the REN-Hydrogen scenario, but not the others), also discussing the various factors which influence the possibility for repurposing networks. Table 3-5 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 2022 report, and the pipeline lengths (TSO and DSO) and approximate diameters data are used from various studies (see Deliverable 3 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 2022[Tõrge! Järjehoidjat pole määratletud.] 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 3-5 Indicative cost analysis for Baltic-Finnish gas pipeline [EHB 2022[40], and multiple other sources, see Deliverable 3 Annex B]

Country	Pipeline type	Pipeline diameter[41]	Length (km)	Cost of repurposing in M€			Cost of new H_2 pipelines 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[42]	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

Comparison of the gas decarbonisation scenarios in terms of energy system impacts

Table 3-6 compares the gas decarbonisation scenarios described above according to a number of criteria:

- **Costs of the gas system:** total costs of the system including investment and operational costs (also considering additional renewable electricity CAPEX needs for hydrogen electrolysis, but excluding other costs in e.g. the electricity or heat sectors, which are out of scope of the project)

[40] https://gasforclimate2050.eu/wp-content/uploads/2022/04/EHB-A-European-hydrogen-infrastructure-vision-covering-28-countries.pdf

[41] Pipeline diameters are categorised based on the EHB 2022 classification: Small < 28 inches, Medium 28-37 inches, Large > 37 inches

[42] 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.

- **Costs for specific gas user categories,** for instance households, industry or the tertiary sector, or on- and off-network users;
- **Market integration and competition:** impact on the further integration of the regional gas market (and its integration with the broader European gas market) as well as the related impact on competition in (particularly wholesale) markets and sector coupling;
- **Investment needs** in gas production, transport infrastructure and adaptation of end-use equipment and appliances, as well as in renewable electricity production for hydrogen electrolysis;
- **Decarbonisation of the energy system:** contribution of the scenarios to reaching the aggregated decarbonisation goals of the region and impact on the total (cumulative) carbon emissions in the time horizon of the study;
- **Resource availability and efficient/sustainable use**, focusing on the use of the regional sustainable biomass and renewable electricity potentials;
- **Energy import dependence,** focusing on the gas import dependence of the concerned countries. This criterion also reflects security of energy supply;
- **Robustness**, that is the associated risks with the scenario and their likelihood.

The comparison of the three decarbonisation scenarios is conducted in relation to the BAU scenario as well as among them. Table 3-6 presents a summary table of the main advantages and disadvantages of the three scenarios

Table 3-6 Comparison of the decarbonisation scenarios according to the criteria

		REN-Biomethane	REN-Hydrogen	Cost Minimal
Costs	Gas system	+ Low overall gas system costs (23% savings compared to BAU) + Biomethane has lowest LCOE o Some SNG use in countries with low biomethane potential, leading to higher costs and conversion losses	o 18% total costs savings compared to BAU (lower savings than other decarbonisation scenarios) – Hydrogen has highest LCOE, even above natural gas price including ETS allowance cost	+ Lowest overall gas system costs (44% savings compared to BAU) o Some SNG use with higher costs and conversion losses to phase out LNG imports
	To specific users	+ Low methane LCOE for on-network users in 2050 – Higher methane LCOE for on-network users in 2030 than BAU due to SNG deployment – High H2 LCOE for off-network users	– High comparative cost to on-grid users even by 2050, particularly industry and refuelling stations, due to high H2 LCOE compared to biomethane + Moderately lower H2 LCOE in 2050 compared to other scenarios which benefits off-network H2 users	+ Low methane LCOE for on-network users in 2050 – High H2 LCOE for off-network users – Higher cost in LT in 2030
Market integration and competition		+ Maintains regionally integrated methane gas markets	+ Higher potential for system flexibility from electrolysers – More fragmented market between different gases – Will require developing liquid hydrogen market	+ Maintains regionally integrated methane gas markets
Investments	Production	+ Investments more evenly distributed across study horizon, even if 2022-2030 having the plurality of investment needs – High investment needs in biogas/biomethane production	+ Investments more evenly distributed across study horizon, even if 2022-2030 having the plurality of investment needs – High investment needs in renewable electricity capacities and electrolysers	– High total investment needs, distributed between biogas/biomethane, renewable electricity, hydrogen and SNG production – Investments concentrated in 2022-2030 period could lead to financing, permitting and infrastructure coordination challenges
	Infrastructure	+ Employs existing natural gas infrastructure (networks and LV storage) to certain extent – Still requires investments in LNG import terminals	+ Facilitates trade of renewable hydrogen through pipelines within and beyond region – Requires development of repurposed/new hydrogen pipelines – Requires development of some hydrogen storage capacity – Still requires investments in LNG import terminals	+ Employs existing natural gas infrastructure (networks and LV storage) to certain extent
	Adaptation of end-uses	– Requires adaptation of some off-grid industrial H2 users – May require gas cleaning process to remove blended hydrogen for sensitive industrial users in 2030 and 2050	– Requires adaptation of higher number of industrial end-users (on and off-grid)	– Requires adaptation of off-grid industrial H2 users – May require gas cleaning process to remove blended hydrogen for sensitive industrial users in 2030
Decarbonisation of the energy system		+ Allows meeting 2050 net decarbonisation targets – Higher 2040 emissions compared to CM scenarios due to remaining reliance on LNG imports	+ Allows meeting 2050 net decarbonisation targets – Higher 2040 emissions compared to CM scenarios due to remaining reliance on LNG imports	+ Allows meeting 2050 net decarbonisation targets + Gas system largely decarbonised already in 2040
Resource availability and efficient/ sustainable use		– Requires capture of CO_2 from biogas upgrading plants or from air to produce SNG – High demand for sustainable biomass, with potential competition with alternative uses	+ Lower pressure on biomass feedstock resources – Highest utilisation of renewable electricity potential of the region	– Requires capture of CO_2 from biogas upgrading plants or from air to produce SNG – Highest demand for sustainable biomass among all scenarios, with potential competition with alternative uses
Energy import dependence		o LNG import dependence until 2030	– Significant dependence on LNG imports up to 2040	+ Reduced energy import dependence already from 2030 due to early scaling up of biomethane
Robustness		+ More balanced use of biogas/biomethane and hydrogen – Risk of lock-in into LNG imports or asset stranding of new LNG terminal investments o Savings relative to BAU scenario depend on LNG price assumptions	– Strong dependence on hydrogen for decarbonisation of gas system, including need for development of dedicated networks – Risk of lock-in into LNG imports or asset stranding of new LNG terminal investments o Savings relative to BAU scenario depend on LNG price assumptions	+ More balanced use of biogas/biomethane and hydrogen o Savings relative to BAU scenario depend on LNG price assumptions

Key findings of the economic and energy system impact assessment and conclusions

The main results of the economic and energy system impact assessment for the Baltic States + Finland region are hereafter presented.

Gas supply

The overall gas supply will decrease in all four scenarios between 2030 and 2050. In the BAU scenario, complete decarbonisation is not achieved and natural gas remains the major gaseous energy carrier in 2050. Gas supply will decrease more significantly in the REN-Methane, REN-Hydrogen and Cost Minimal (CM) scenarios where in addition, full decarbonisation is achieved by 2050. The REN-Hydrogen scenario relies mainly on on-network renewable hydrogen and the two other scenarios on on-network biomethane, although all decarbonisation scenarios rely on off-network renewable hydrogen for certain hard-to-decarbonise applications.

Investments in clean gas production capacities

The Cost Minimal scenario has the highest cumulative gas production investment needs, at almost 11 billion EUR (discounted value) in the 2022-2050 horizon, which is significantly higher than in the REN-Hydrogen (8 billion EUR) and REN-Methane (6.5 billion EUR) scenarios. However, when also considering the LNG terminal investment needs, the overall investment needs for the three decarbonisation scenarios are similar at around 10-11 billion EUR across the study horizon. The CM scenario has a more balanced distribution of investments for hydrogen, methane and SNG production, while the REN-Hydrogen has the highest investment needs for hydrogen production (around 6.5 billion EUR).

Furthermore, the renewable gas production investment needs in the CM scenario are frontloaded (concentrated in the 2022-2030 period), which despite presenting benefits in the form of the accelerated phase out of LNG imports could lead to difficulties in realising the investments due to issues such as obtaining the necessary financing sources but also potential bottlenecks in the supply chain and related to e.g. permits for gas production projects and coordination with the development of the necessary infrastructure, such as connection pipelines and in the case of hydrogen the renewable electricity capacity.

Investments in wind energy capacity

Next to clean gas investments, the gas decarbonisation scenarios also require high renewable electricity generation capacities. Two alternatives were considered: i) deployment of on-shore wind energy and ii) deployment of off-shore wind energy. The two alternatives lead to different capacity and investment requirements. As the REN-Hydrogen scenario requires much more electricity than the other pathways, the related investments are substantially higher and more than double compared to BAU (equal to approximately EUR 3.7 billion for onshore wind energy facilities and EUR 5.3 billion for deployment of offshore capacities). Higher investments lead to higher output levels, with the REN-Hydrogen scenario leading to higher output levels compared to the BAU when wind energy capacities are installed offshore than when these are installed off-shore. The REN-Methane scenario also requires higher investments in wind energy capacities than the BAU and leads to higher output levels. Finally, in the Cost minimal scenario, wind energy investments are similar to the BAU and this leads to lower activity levels compared to the other decarbonization scenarios.

Gas supply costs

Total gas supply costs (including CAPEX and OPEX) are in all decarbonization scenarios lower compared to the BAU: by 44% in the REN-Methane scenario, by 18% in the REN-Hydrogen scenario and by 23% in the Cost minimal scenario. The reduced gas expenditures generate a positive and negative impact on the economy; on the one hand the activity of gas transport and supply companies falls due to the lower gas demand, but on the other hand savings in gas costs are redirected towards the consumption of other goods and services.

With respect to the unit gas costs, the Cost Minimal scenario leads to the lowest cost for gas users both in the 2030 and 2050 horizons across all four Member States, except Lithuania in 2030 due to some investments in SNG production. Energy cost reductions have a positive impact on domestic economic activity levels, especially in the manufacturing sectors. For this criterion, the Cost-minimal scenario is the most appropriate option in the long-term.

Overall economic output and employment

Both in the assumption of self-financing (with crowding-out of investments in other activities) and external financing (without crowding-out) of investments, the cumulated economic output (taking into account the direct and indirect effects of the energy investments) and employment would in the 3 decarbonisation scenarios in each of the 4 countries be (substantially) higher than in the BAU scenario. The Cost Minimal scenario clearly leads to the highest positive impact on economic output and employment.

Greenhouse gas emissions

Under the BAU scenario, the Baltic region will not achieve complete decarbonisation by 2050. The remaining emissions are mainly attributable to natural gas consumption. As the 3 decarbonisation scenarios assume complete gas decarbonisation by 2050, the 4 countries' emissions will fall sharply due to the reduced fossil gas use which is partly substituted by increasing domestic renewable gas production. In the Cost Minimal scenario, the countries will even be decarbonised by 2040 due to early phase-out of LNG imports for pipeline and off-network gas majorly based on renewable hydrogen supply.

Conclusions regarding the impacts of the decarbonisation scenarios

Based on the economic and energy system impacts assessment undertaken in this analysis and the key findings presented supra, a**ll 3 gas decarbonisation scenarios** present major economic and energy system benefits compared to the BAU scenario. Although the decarbonisation pathways require higher investment levels than the BAU scenario, the positive direct and indirect impacts in terms of economic output, employment, energy costs, import dependence, outweigh the higher overall capital expenditures.

Moreover, the **Cost Minimal scenario is preferred from both the economic and energy system impacts perspectives**. The scenario leads to the highest cumulative output gains compared to the BAU scenario - between 0.23-0.24% of (regional) GDP. Output changes are mainly driven by changes in gas expenditures (fuel mix) and prices (LCOEs). In terms of job creation, the Cost minimal scenario leads to 20,000 – 21,000 additional jobs compared to the BAU on average (+0.43%).

In terms of **energy system impacts**, the total gas system costs are lower in the Cost Minimal scenario than in any other scenario (44% savings compared to the BAU). The scenario performs well also in terms of market integration and competition, meeting the decarbonisation targets, energy import dependence and robustness to uncertainty. The main disadvantage of the scenario is the need to realise significant investments in renewable gas production already in the 2022-2030 period (9.6 billion EUR compared to 4.9 - 6.0 billion EUR in other scenarios), and the need to mitigate the associated risk of short-term higher gas costs to certain consumers and countries to recover these investments; furthermore the availability of suitable biomass feedstocks for biogas/biomethane production and renewable electricity for electrolysis is key to successfully realise this scenario.

3.5 Risk analysis of the scenarios for a decarbonised Baltic Regional Gas Market (Deliverable 5)

The objectives of Deliverable 5 were to identify the relevant risks related to the identified gas decarbonisation scenarios; assess the likelihood, severity and mitigation measures of each identified risk; for the Baltic Regional Gas Market countries, pinpoint any risks specific to a sub-set of countries; and assess and pinpoint for each identified risk the extent to which it would apply to the different gas decarbonisation scenarios.

Table 3-7 presents the risk assessment, including applicable scenarios, likelihood and severity. **The results indicate that the main risks for the decarbonisation scenarios are related to various economic, regulatory and technical factors which may hinder the deployment of decarbonisation assets.**

The main risks potentially impacting the gas decarbonisation scenarios are:

- ✓ **Risk 1 – Economic turndown and instability can limit the ability of local gas producers, users, network operators and authorities to invest in gas decarbonisation measures**
  Economic turndown and instability can occur as a consequence of economic, environmental or social shocks, which can be increasingly expected due to climate change. This will in turn decrease the ability and willingness of stakeholders to invest because of higher prices (e.g. due to inflation), lower available financial resources (e.g. due to economic recessions) or limited competitiveness of renewable energy projects.

- ✓ **Risk 6 – Infrastructure cannot be adequately or timely developed, including repurposing or adaptation of natural gas infrastructure**
  Implementation of gas decarbonisation measures can be hindered or delayed by long lead times to build new or refurbish/repurpose existing infrastructure. This can result from a lack of adequate planning at the regional level, or a lack investments into dedicated networks due to high uncertainties.

- ✓ **Risk 8 - Security of gas supply can be threatened due to external energy dependence**
  External shocks (e.g. arising from environmental disasters or geopolitical tensions) can lead to gas supply disruptions. Countries that are highly dependent on foreign gas supply are more likely to face security of supply issues as they have less control on their energy mix.

- ✓ **Risk 9 - Available inputs for production of R/LC gases, e.g. renewable electricity or biomass can be insufficient**
  Decarbonisation of the gas system via the replacement of natural gas with biomethane can only be achieved if the availability and adequacy of biomass feedstock is sufficient. Similarly, decarbonisation through hydrogen production is highly dependent on hydrogen infrastructure development and market demand, as well as the availability of renewable energy.

- ✓ **Risk 10 - Investments in methane infrastructure can lead to lock-in on natural gas or asset stranding**
  Ongoing and planned investments in natural gas infrastructure may lead to a structural lock-in on natural gas and delay the transition to decarbonization options including electrification of building heating and switching to renewable gas.

- ✓ **Risk 11 - Policies and regulations can present barriers to implementation of gas decarbonization actions**

  Although policies and regulations allow to enhance the decarbonization of the gas sector, they can potentially also have negative impacts. This is mainly linked to the fact that policy and regulatory uncertainties can defer investment decisions.

- ✓ **Risk 14 - Key gas decarbonisation technologies may not reach sufficient cost or performance improvements**

  The capacity to reach full decarbonization of the gas sector and the pace at which it is reached will highly depend on the competitiveness of key gas decarbonization technologies compared to fossil fuel-based technologies, and on whether their cost and performance can be improved.

Table 3-7 Overview of risk assessment for gas decarbonization scenarios

Category	No	Risk	Applicable scenarios			Likelihood	Severity
			REN-M	REN-H	CM		
Economic	1	Economic turndown and instability can limit ability local of gas producers, users, network operators and authorities to invest in gas decarbonisation measures	✓	✓	✓✓	High	**Medium**
	2	Supply dependence and bottlenecks for energy technologies can increase costs/slow down transition	✓	✓✓	✓	Low	**Medium**
	3	Fossil gas decarbonisation can negatively affect competitiveness of industrial users	✓	✓	✓✓	Low/ Medium	**Medium**
Energy markets	4	Developments in global energy markets impact competitiveness of gas decarbonisation solutions	✓	✓✓	✓	Medium	**Medium**
	5	Fragmentation of regional/national gas networks and markets	✓	✓✓	✓	Medium	**Medium**
	6	Infrastructure cannot be adequately or timely developed, including repurposing or adaptation of natural gas infrastructure		✓✓		Low	**High**
	7	Security of gas supply can be threatened due to adequacy/flexibility issues of domestic/regional energy system		✓✓		High	**Low**
	8	Security of gas supply can be threatened due to external energy dependence	✓	✓	✓	Low	**High**
	9	Available inputs for production of R/LC gases, e.g. renewable electricity or biomass can be insufficient	✓✓	✓✓	✓✓	Medium	**High**
	10	Investments in methane infrastructure can lead to lock-in on natural gas or asset stranding	✓✓	✓✓	✓	Medium	**High**
Regulatory	11	Policies and regulations can present barriers to implementation of gas decarbonization actions	✓	✓✓	✓	Low	**Medium/ High**
Social & environmental	12	Some specific gas decarbonisation actions can result in adverse environmental and climate impacts	✓✓		✓	Low	**Medium**
	13	Public opposition, due to (perception of) negative impacts	✓✓	✓✓	✓✓	High	**Low**
Technological	14	Key gas decarbonisation technologies may not reach sufficient cost or performance improvements	✓✓	✓✓	✓✓	Medium	**High**
	15	Safety risks or their perception restrict infrastructure development or certain supply/demand solutions		✓		Medium	**Low**
Geopolitical	16	Geopolitical events can divert resources and attention from gas decarbonisation measures	✓	✓	✓	Medium	**Medium**

The REN-Hydrogen scenario is clearly the riskiest scenario as it is affected by more risks than the REN-Methane and Cost Minimal scenarios. The required investments for building new hydrogen infrastructure or repurposing/retrofitting existing natural gas infrastructure are significant (**Risk 6**). In addition, the scenario still requires large capital investments into LNG terminals as is will be significantly reliant on LNG gas imports until 2040. This can lead to a lock-in on natural gas or asset stranding (**Risk 10**). Adopting an appropriate regulatory framework for hydrogen at EU and national levels is key for the achievement of the REN-Hydrogen scenario, but this may take some time. The uncertainty about policies and regulation may delay investments in hydrogen development projects (**Risk 11**). Finally, there is no certainty about the maturity of hydrogen technologies and whether their cost and performance will be competitive (**Risk 14**).

The analysis also identifies possible mitigation measures for each of the assessed risks. The table below summarises these mitigation measures for the main risks. These mitigation measures also allow to address other assessed risks (see last column).

Table 3-8 Mitigation measures for main identified risks

No	Risk	Mitigation measures	Other risks addressed
1	Economic turndown and instability can limit ability local of gas producers, users, network operators and authorities to invest in gas decarbonisation measures	– Economic and financial measures to prevent an economic turndown or reduce its impact	4, 13, 16
		– Provide adequate price signals to economic actors to stimulate investments in decarbonisation measures, such as carbon pricing, energy taxation reform, financial support, risk sharing, public-private partnerships	3, 4, 6, 13, 14
6	Infrastructure cannot be adequately or timely developed, including repurposing or adaptation of natural gas infrastructure	– Proactive national and supra-national planning of methane network investments and of hydrogen network investments	7, 10, 11, 14
		– Regular market studies for the Baltic region to identify and assess the expected developments in supply and demand of renewable gases, based on contacts with market operators and sector associations	7, 9
		– Ensure appropriate regulation and public control of gas networks, in particular when these are partially or fully privately owned and need to be refurbished or repurposed, in order to ensure timely investments in renewable or decarbonized gas transport (and large-scale storage) infrastructure	2, 5, 11, 15
8	Security of gas supply can be threatened due to external energy dependence	– Work on further solidarity arrangements aimed at ensuring that protected customers have continued access to gas in times of crisis	4, 13, 16
		– Decrease the overall natural gas consumption by implementing energy efficiency measures and by shifting towards locally generated renewable energy sources	3
		– Pool gas demand of the BRGM countries to have a greater bargaining power in procurement negotiations with gas exporting countries	4, 16
9	Available inputs for production of R/LC gases, e.g. renewable electricity or biomass can be insufficient	– Allocate adequate funding and incentives to promote the development of renewable energy sources, including solar, wind, and biomass.	3, 4, 8, 14
		– Invest in upgrading and expanding the power grid infrastructure to accommodate the increasing penetration of renewable energy sources.	7

No	Risk	Mitigation measures	Other risks addressed
		– Implement climate resilience strategies to address the potential impact of natural fluctuations on renewable energy production. This includes improving forecasting capabilities, investing in energy storage systems, and promoting diversification of renewable energy sources.	-
		– Promote sustainable biomass sourcing and cultivation practices to ensure a reliable and environmentally responsible feedstock supply for biomethane production. Encourage circular economy approaches, waste-to-energy initiatives, and land-use planning that prioritizes sustainable biomass production.	12
10	Investments in methane infrastructure can lead to lock-in on natural gas or asset stranding	– Reduce investments in new natural gas network infrastructure to the strict minimum, and ensure that any new asset is future-proof	-
		– Introduce a legal ban on connecting new residential and tertiary buildings to the natural gas grid (unless the concerned buildings will mainly use renewable energy).	-
		– Assess whether and how the natural gas network tariffication can be reviewed to anticipate the consequences of reduced natural gas use and stranded assets.	11
11	Policies and regulations can present barriers to implementation of gas decarbonization actions	– Development of a coordinated strategy for the gas and hydrogen sectors in the BRGM region as well in the individual concerned Member States	3, 4, 5, 6, 7, 8, 10, 13, 14
		– Develop clear and supportive legal frameworks and regulations for renewable energy and low-carbon gas production. Streamline permitting processes, provide incentives for project development, and ensure compliance with environmental standards to expedite the deployment of hydrogen and biomethane projects	9
14	Key gas decarbonisation technologies may not reach sufficient cost or performance improvements	– Publicly funded R&D&I programs focused on the development and improvement of gas decarbonisation technologies, renewable energy technologies, energy storage and biomass conversion processes. This will enhance the efficiency and scalability of both hydrogen and biomethane production methods, making them more cost-effective and commercially viable.	1, 3, 4, 9, 11, 13
		– Reducing subsidies to fossil fuel-based technologies to increase the competitiveness of gas decarbonisation technologies.	3, 4, 16
		– Transparent ambitions and clear planning at national level to reduce the uncertainty and risks for investing in gas decarbonization technologies.	3, 4, 5, 6, 7, 8, 10, 13, 14

3.6 Sensitivity analysis of the scenarios for a decarbonised Baltic Regional Gas Market (Deliverable 6)

The sensitivity analysis conducted in Deliverable 6 aimed to complement the output of Deliverables 3 and 4 by evaluating factors of uncertainty regarding the development of clean gas facilities in the Baltic Regional Gas Market. To this end, 8 sensitivity scenarios were analysed each one treating a different dimension of uncertainty: capital costs and investment requirements, EU ETS price and electricity network fees. The sensitivity analysis provided additional insights to the results obtained in Deliverables 3 and 4 by presenting a plausible range of results regarding the investment requirements for the development of clean gas facilities, the LCOEs and their repercussions in economic output levels and employment.

Sensitivity analysis of the energy system modelling

The sensitivity analysis has been performed for the three decarbonisation scenarios: REN-Methane, REN-Hydrogen, and Cost Minimal scenario. These scenarios are evaluated using different values for selected parameters to evaluate the sensitivity of the energy system modelling outcomes to changes in these input parameters. The business-as-usual scenario is excluded from the sensitivity analysis because the main objective is to compare the performance of the scenarios that target full decarbonisation of the regional gas system under different energy system modelling assumptions. The analysed sensitivity parameters are the following:

1. Technology CAPEX: Biomethane production systems
2. Technology CAPEX: Renewable hydrogen production systems
3. EU ETS price
4. Network fee (grid charge) for renewable electricity

A total of four sensitivity parameters have been chosen for analysis, with two different sensitivity levels for each parameter, resulting in eight sub-sensitivities. These sub-sensitivities are applied to the three decarbonisation scenarios (REN-Methane, REN-Hydrogen, and Cost Minimal scenario), leading to a total of 24 modelling simulation runs. Table 3-9 provides an overview of all the sensitivity parameters and their corresponding sensitivity levels.

Table 3-9 Sensitivity parameters and the corresponding sensitivity levels

Sensitivity analysis		CAPEX of H_2 technologies	CAPEX of BM technologies[43]	ETS price[44]	Network fees for electricity
Sensitivity 1 (S1)	S 1.1	+20%	-	-	-
	S1.2	-20%	-	-	-
Sensitivity 2 (S2)	S 2.1	-	+20%	-	-
	S 2.2	-	-20%	-	-
Sensitivity 3 (S3)	S 3.1	-	-	+20%	-
	S 3.2	-	-	+40%	-
Sensitivity 4 (S4)	S 4.1	-	-	-	+20%
	S 4.2	-	-	-	-20%

Sensitivity analysis of the macro-economic modelling

The macroeconomic modelling quantifies the impact of alternative assumptions regarding cost developments and investment needs on the economy. The macroeconomic analysis is performed for the S1 and S2 set of scenarios and computes the output and employment changes. Uncertainty regarding the evolution of costs associated to the deployment and the production of clean fuels makes these sensitivities most relevant from a macroeconomic perspective.

The model takes as inputs the CAPEX and the LCOE from the energy model. Investments provide a demand stimulus in the economy and direct economic gains. Gas prices on the other hand, influence production costs and change demand for domestically produced goods through income and substitution effects.

Key findings and conclusions

The impacts of the considered changes in the sensitivity analysis are not very high:

- As the LCoEs differences between gases are high (particularly between biomethane and hydrogen, the preference order would generally not be altered by CAPEX changes (even if combining two parameters);
- The investment needs would in all decarbonisation scenarios nonetheless be affected by changes in CAPEX values;
- The REN-Biomethane scenario would respond positively to increased ETS prices by accelerating the decarbonisation of the gas system through early deployment of hydrogen in local applications.

The Cost Minimal scenario remains the preferred pathway from an energy system’s perspective:

- The probability is low that either the REN-Hydrogen or REN-Biomethane scenario would become more attractive than the CM scenario;
- In case of unit CAPEX increases there would need to pay specific attention to the investment needs under the CM scenario, but the overall recommendations would not be changed.

[43] Increase/decrease as per the base Technology considerations
[44] As ETS prices are only trend, only an increasing trend makes sense for the sensitivity analysis

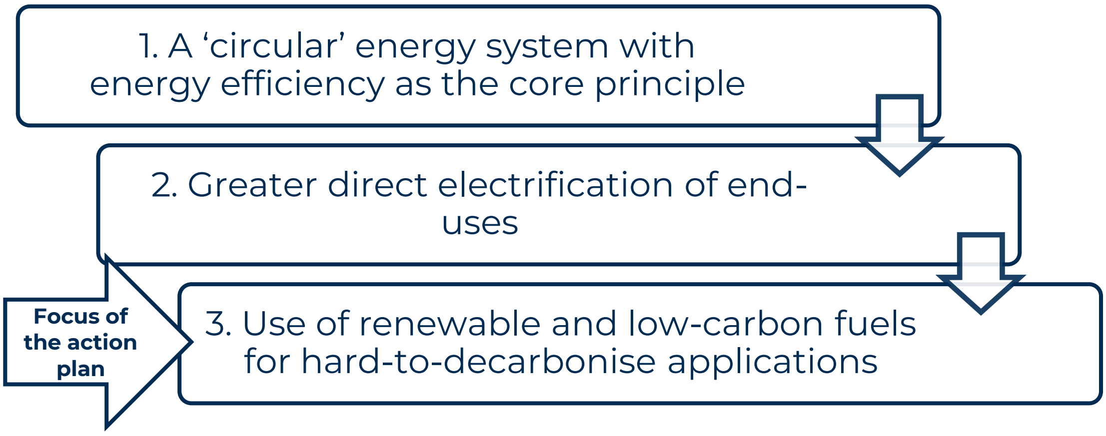
The macro-economic analysis reveals that higher investment levels (due to assumed CAPEX changes) lead in general to higher economic output gains. However, this effect is lessened by the impact of energy prices; higher energy prices lead to lower demand for products and hence lower economic output. If we rank the decarbonisation scenarios in terms of their economic efficiency, the Cost minimal pathway remains the best option, if we consider only the investment and price effects, as for each € spent the regional economic output increases by approximately 1.63 €. Additionally, job creation in the Cost minimal scenario is on average higher at the regional level compared to the BAU and the other decarbonisation pathways. The cumulative economic output varies compared to the Base case by -2.8% to 4.3% in the REN-Methane scenario, by -4.9% to 4.9% in the REN-Hydrogen scenario and by -1% to 3.3% in the Cost minimal pathway.

3.7 Action plan for achieving a decarbonised Baltic Regional Gas Market (Deliverable 7)

Deliverable 7 presents an action plan detailing various policies for achieving a carbon neutral gas system in the Baltic states and Finland. As such, the actions proposed should facilitate the achievement of the three decarbonisation scenarios employed throughout the study.

The actions of this plan focus on promoting the production and use of renewable and low-carbon gases for hard-to-decarbonise sectors and applications. Energy efficiency and direct electrification measures aiming at reducing overall gas demand are not included in the plan, but should nonetheless be prioritised ahead of policies substituting natural gas by renewable and low-carbon gases, as shown in the figure below. **This means policymakers should pay particular attention at realistically forecasting future gas demand, implementing and taking into account ambitious energy efficiency and electrification measures.** The plan does include measures to considering and providing a level-playing field for the most cost-efficient decarbonisation solution (energy efficiency measures, direct electrification or use of renewable and low-carbon fuels).

Figure 3-7 Focus of the action plan within the hierarchy of solutions for energy system decarbonisation



The action plan describes the 12 proposed actions to decarbonise the gas system of the Baltic states and Finland, categorised according to 5 action sets as illustrated in Figure 3-8. The specific measures which constitute each action are presented in Table 3-10.

The proposed measures take as a starting point the policy measures adopted or proposed by the four national governments, by conducting a review of the current policy landscape at the EU and national level. Hence, the proposed measures are meant to complement (or revise) the current regulatory frameworks, and may coincide with measures being considered by national governments but not yet publicly announced.

Figure 3-8 Actions for the decarbonisation of the gas system of the Baltic states and Finland

Action set 1 - Governance of gas system decarbonization

- 1) Improve the governance structure and strategic policies for renewable gases

Action set 2 - Gas market design and integration

- 2a) Further integrate the Baltic Regional Gas Market and facilitate access for new actors
- 2b) Review energy certification system (including biogas and off-grid gas and extension to low-carbon fuels)
- 2c) Consider measures to develop a liquid hydrogen/derivatives market in the long-term

Action set 3 - Support and requirements for renewable and low-carbon gas production and/or consumption

- 3a) Review/introduce coordinated production and/or consumption support measures to foster methane-based gases
- 3b) Assess the need for and implement specific support measures for renewable hydrogen production and/or consumption
- 3c) Consider legal ban on connecting new buildings to the natural gas grid and/or to new gas boilers

Action set 4 - Infrastructure planning

- 4a) Increase regional methane/hydrogen/electricity infrastructure planning coordination
- 4b) Review and harmonise connection requirements and coordinated planning for transmission and distribution
- 4c) Review and harmonise gas quality standards where appropriate

Action set 5 - Energy and carbon taxation

- 5a) Review energy excise tax across energy products
- 5b) Review/introduce carbon taxation

Contributions of the proposed actions to the hierarchy of solutions for energy system decarbonisation

While the proposed actions focus on the gas sector, they can as mentioned aim to improve the consideration and level-playing field for cost-efficient decarbonisation solutions, whether that is the use of renewable and low-carbon gases or other approaches. Hence, 3-10 Specific measures of the action plan for decarbonisation of the Baltic Regional Gas Market

illustrates where in the hierarchy of solutions for energy system decarbonisation each of the proposed actions fits in.

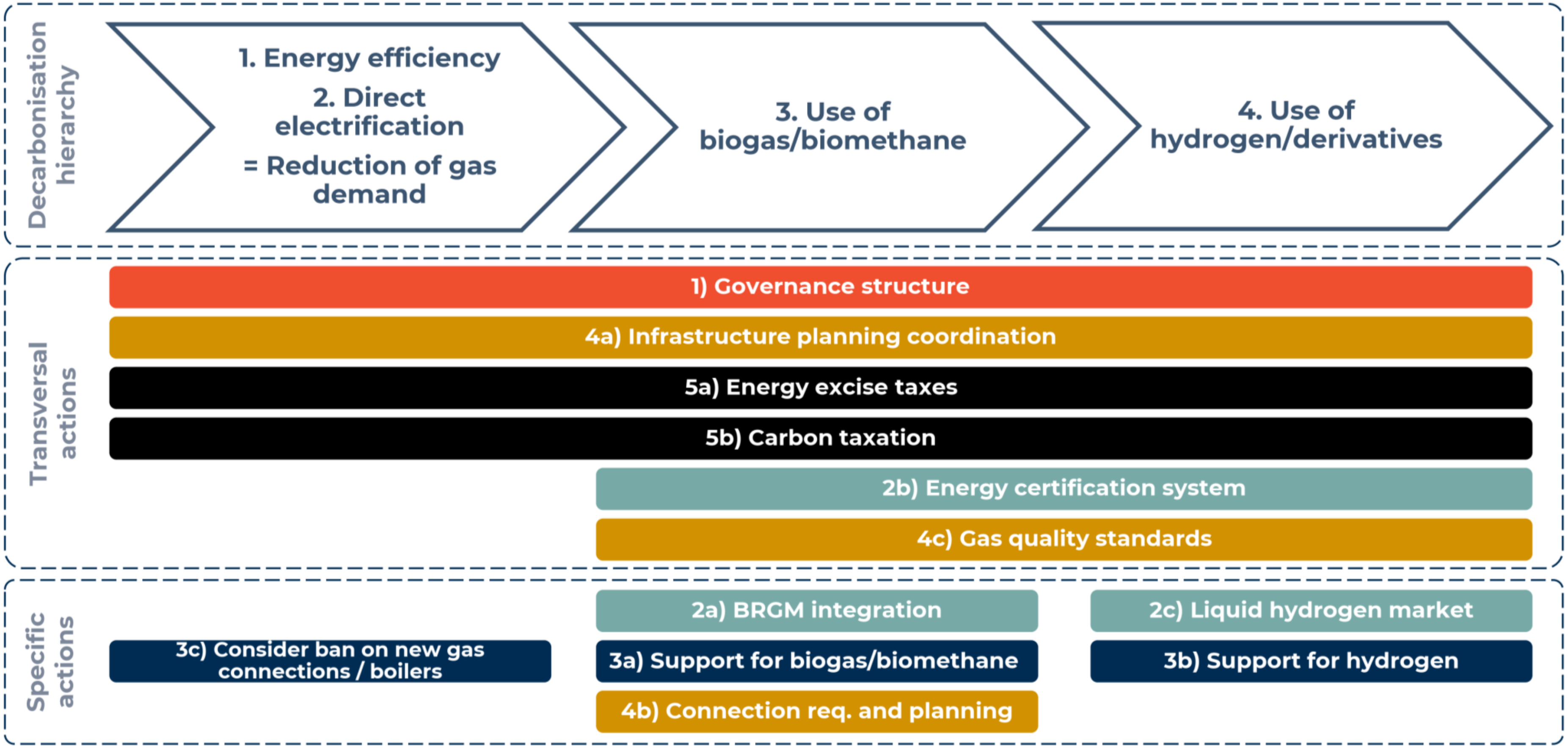
It can be seen that many actions are transversal, aiming to ensure the most cost-efficient solution is chosen for decarbonising the Baltic Regional Gas Market, whether that solution is energy efficiency measures, direct electrification, biogas, biomethane, hydrogen or derivatives. Complementing those, a few specific actions aim to incentivise biogas/biomethane or hydrogen/derivatives when cost-efficient.

Table 3-10 Specific measures of the action plan for decarbonisation of the Baltic Regional Gas Market

Action number	Specific measure	Value chain step								Gas type		Geography
		Production	Import	Injection	Gas transport (domestic)	Gas transport (cross-border)	Trading	Consumption (off-grid)	Consumption (grid-connected)	Biogas/ biomethane	Hydrogen	
1	Develop Regional Strategy for Decarbonised Gas Development	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	Regional
1	Determine targets for decarbonised gas production by 2030, 2040 and 2050	✓								✓	✓	All MSs (separately)
1	Designate preferred locations for biogas/biomethane and hydrogen production units	✓		✓						✓	✓	All MSs (separately)
1	Coordinate implementation of Hydrogen and Decarbonised Gas Market Package (HDGMP) provisions	✓		✓	✓	✓	✓	✓	✓	✓	✓	Regional
1	Extend the mandate of NRAs to include regulation of decarbonised and renewable gases	✓		✓	✓	✓	✓	✓	✓	✓	✓	All MSs (separately)
1	Finalise efforts to create a genuine single entry-exit Baltic-Finnish gas market					✓	✓			✓		Regional
2a	Ensure the availability of longer-term products						✓			✓		Regional
2a	Support robust gas reference prices widely available to market participants						✓			✓		Regional
2a	Consider requiring gas importers/traders to trade a proportion of imports via forward and DA market						✓			✓		Regional
2b	Harmonise energy certification schemes	✓	✓				✓	✓	✓	✓	✓	Regional
2c	Further develop public and privately developed hydrogen price benchmarks										✓	Regional
2c	Facilitate the balancing of supply and demand in the future hydrogen systems	✓					✓		✓		✓	Regional
2c	Develop a hydrogen target market model with minimum rules for harmonisation in line with the HDGMP			✓	✓	✓	✓				✓	Regional
2c	Assess the potential for hydrogen domestic hydrogen production and imports	✓	✓								✓	Regional
2c	Actively participate in EU Energy Platform, including on future joint hydrogen purchases		✓								✓	All MSs (separately)
2a	Conduct a coordinated review on the focus on certain biogas/biomethane uses							✓	✓	✓		Regional
2a	Consider the introduction of joint projects and joint support mechanisms	✓		✓						✓	✓	Regional
3a	Consider gradual opening support mechanisms to more renewable and low-carbon gas types & routes	✓								✓	✓	All MSs (separately)

Action number	Specific measure	Value chain step								Gas type		Geography
		Production	Import	Injection	Gas transport (domestic)	Gas transport (cross-border)	Trading	Consumption (off-grid)	Consumption (grid-connected)	Biogas/ biomethane	Hydrogen	
3a	Review support mechanisms to further incentivise market participation	✓								✓	✓	All MSs (separately)
3a	Assess profitability gap for biogas/biomethane and adapt support accordingly	✓								✓		Regional
3b	Conduct a review on the current policy focus on certain hydrogen uses							✓	✓		✓	All MSs (separately)
3b	Agree on a common approach to meeting the national sectoral sub-targets of the revised REDII							✓	✓		✓	Regional
3b	Analyse possibility for regional cooperation in renewable electricity for hydrogen production	✓									✓	All MSs (separately)
3c	Consider ban on connecting new buildings to the gas grid and on installing new fossil fuel boilers								✓	✓		All MSs (separately)
4a	Require publication of NDP by gas TSO				✓	✓				✓		FI
4a	Adapt and harmonise NDP framework, to e.g. use same scenarios and assumptions for the NDPs				✓	✓				✓		Regional
4a	Require regional cooperation of gas, electricity and in the future hydrogen network operators				✓	✓				✓	✓	Regional
4b	Review and harmonise connection requirements for renewable and low-carbon gas production			✓						✓		All MSs (separately)
4b	Introduce coordinated planning for transmission and distribution networks			✓	✓					✓		All MSs (separately)
4c	Review O_2 content gas quality specifications to facilitate biomethane injection				✓	✓				✓		Regional
4c	Define responsibility for ensuring and monitoring the quality of injected gas			✓						✓	✓	All MSs (separately)
4c	Adopt harmonised gas quality specifications for hydrogen blending in methane networks				✓	✓					✓	Regional
5a	Revise energy taxation rates, anticipating the recast Energy Taxation Directive							✓	✓	✓	✓	Regional
5a	Identify further initiatives to accelerate the phasing out of subsidies for fossil fuels	✓						✓	✓	✓	✓	Regional
5b	Introduce a carbon tax on energy use							✓	✓	✓	✓	LT
5b	Gradually increase carbon tax rates in coordinated manner							✓	✓	✓	✓	Regional

Figure 3-9 Relationship of proposed actions to the hierarchy of solutions for energy system decarbonisation



Risks addressed by the action plan

As detailed in section 3.5, Deliverable 5 of this project assessed 16 risks to the decarbonisation of the Baltic Regional Gas System, identifying seven of them as main risks. The actions proposed under Deliverable 7 address these risks, and in particular six of the main risks (risk 1 regarding the impact of the economic turndown and instability is also addressed, but not highlighted here as it involves often temporary actions or actions outside of the remit of energy ministries). The link between the plan actions and the six relevant main risks is illustrated in Figure 3-10. In particular, the following can be noted:

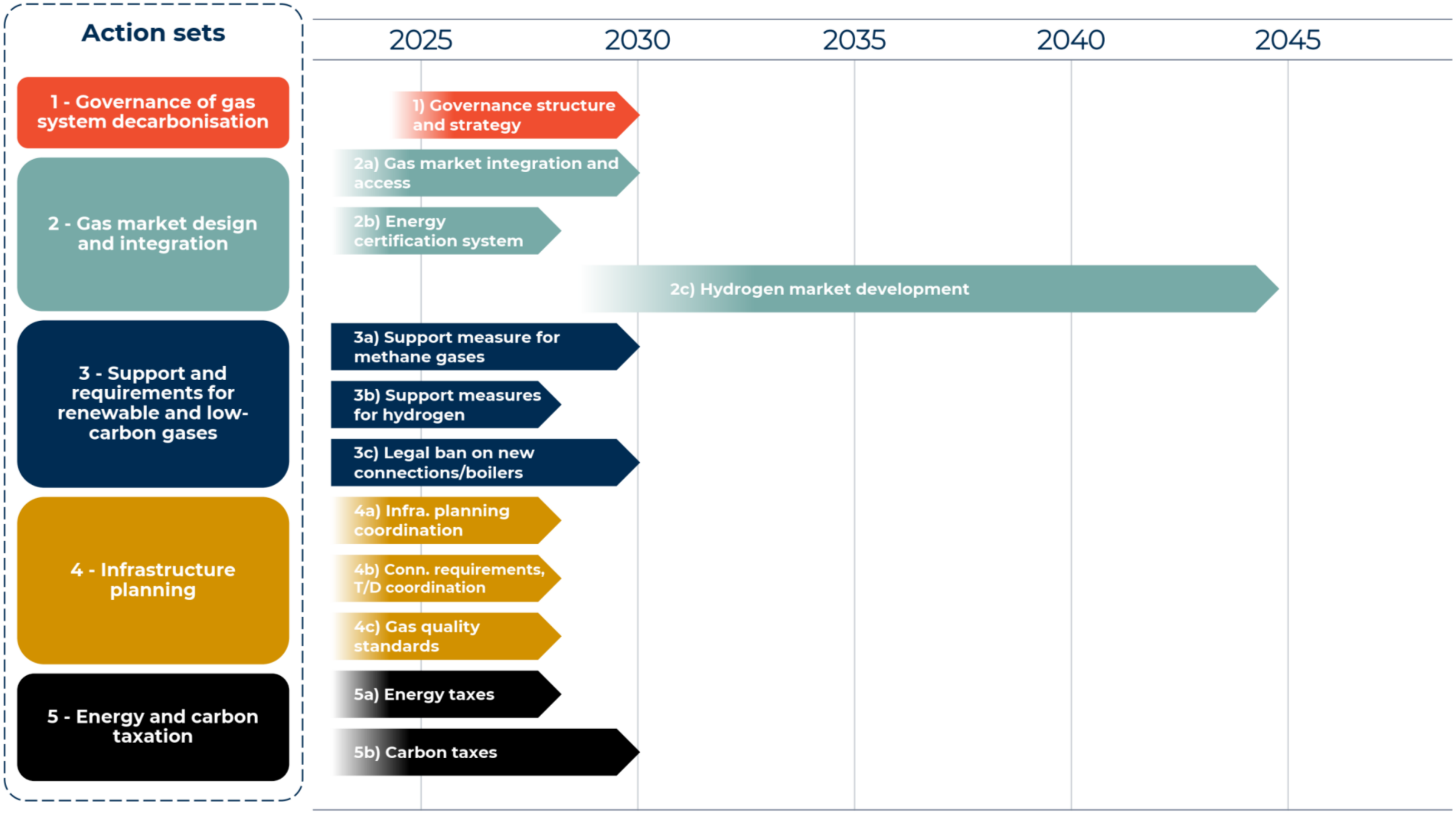
- ✓ **Risk 6 "Infrastructure cannot be adequately or timely developed, including repurposing or adaptation of natural gas infrastructure"** as well as **Risk 10 "Investments in methane infrastructure can lead to lock-in on natural gas or asset stranding"** are mitigated especially by the infrastructure planning-related actions of action set 4. In addition, the action 3c) on considering a ban on new building connections to the gas grid and/or installation of new gas boilers could send a strong signal to avoid the lock-in or stranding of natural gas assets;
- ✓ **Risk 8 "Security of gas supply can be threatened due to external energy dependence"** is addressed by the governance action 1, but also the actions of the set 3) which aim to support the deployment of renewable gases production and consumption. Logically, by increasing domestic production these actions should have a direct impact on external energy dependence;
- ✓ **Risk 9 "Available inputs for production of R/LC gases, e.g. renewable electricity or biomass can be insufficient"** is mitigated by actions of the set 2 (gas market design and integration) and set 3 (Support and requirements for renewable and low-carbon gases). These action sets should not only incentivise the exploitation of sustainable and renewable energy potentials, including from areas which would not be profitable without some support, but also facilitate their trading, thus ensuring the best locations within the region are exploited, rather than each country exploiting its potential to meet primarily domestic demands;
- ✓ **Risk 11 "Policies and regulations can present barriers to implementation of gas decarbonization actions"** is mitigated particularly by action 1 "Improve the governance structure and strategic policies for renewable gases". By improving the governance structure in order to identify the necessary policy changes as well as to provide clear guidance to all stakeholders, the action should significantly mitigate the regulatory risk;
- ✓ **Risk 14 "Key gas decarbonisation technologies may not reach sufficient cost or performance improvements"** is addressed by various actions sets (on market design and integration, support to renewable and low-carbon gases, and energy and carbon taxation). The actions within those sets should all contribute to improving the business case of renewable and low-carbon gases vis-à-vis natural gas, thus facilitating their deployment and leveraging of economies of scale and learning effects (in coordination with other EU Member States).

Figure 3-10 Action plan measures and risks addressed

Timeline and summary of the proposed actions

Quick implementation of the actions is paramount for maximising the societal net benefits of decarbonising the region's gas system. Figure 3-11 presents the timeline for implementation of the actions comprised in the plan for decarbonisation of the gas system in the Baltic states and Finland. Deliverable 4 of this project has shown that the Cost Minimal scenario presents the lowest total costs in the considered time horizon, with the early substitution of LNG imports ahead of 2040 being a main driver. This implies that many of the decarbonisation policies for the region should substantially reduce the fossil gas use already by 2030, which would require that the policies be in place in the next years. As shown in the action plan timeline most of the proposed actions have indeed a short implementation horizon, and should be in place at most by 2030 (with the notable exception of actions to develop a liquid hydrogen market). The fastest these actions can be implemented, the higher would be the societal net benefits. The main exceptions are actions 2a) and 2b) which concern (transitional) support to methane gases and hydrogen/derivatives, respectively. Here, cost reductions in hydrogen production technologies will be driven in part by learning effects and economies of scale influenced by investments in the EU and globally. Hence, there could be a case for phasing/spreading out economic support. But in order to avoid competition distortion, this can be done in coordination with other EU Member States, and a balance should be found with decarbonising the region's gas system sufficiently fast.

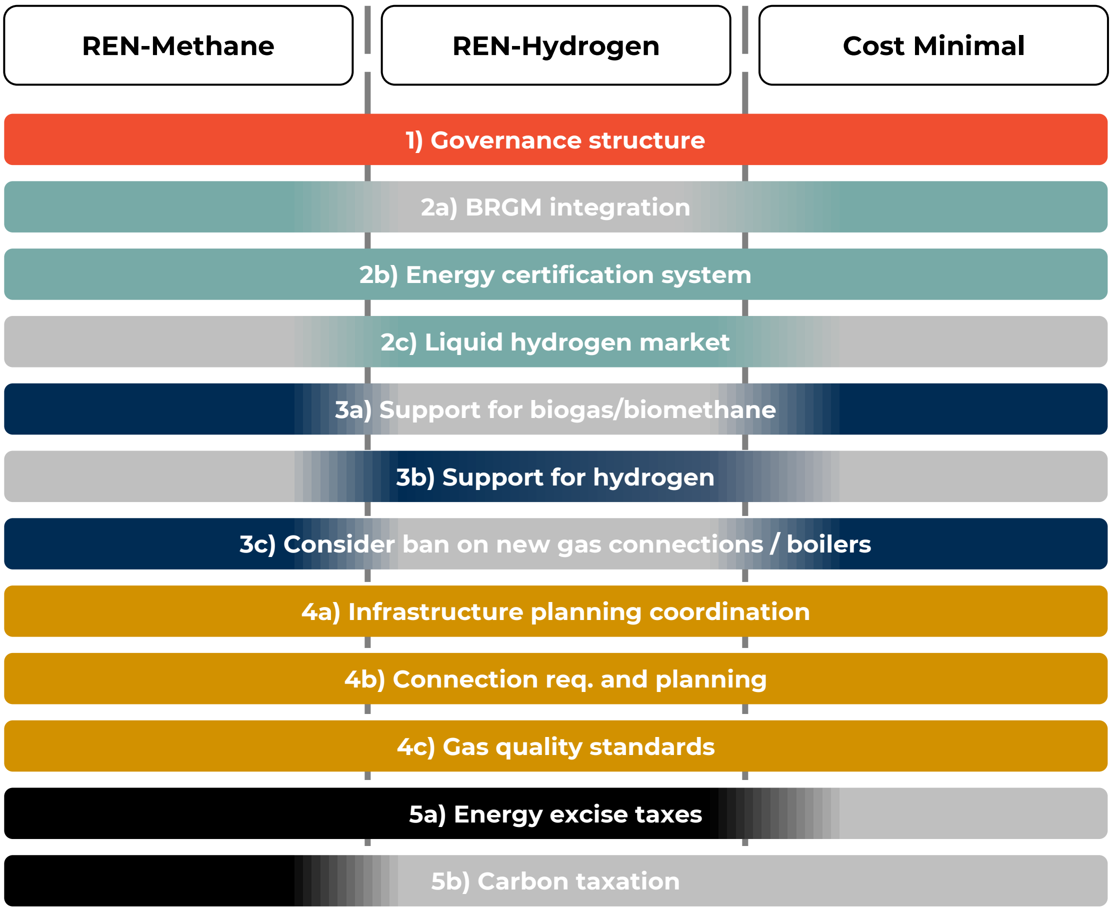
Figure 3-11 Action timeline for decarbonisation of the gas system of the Baltic states and Finland



Action relevance to the gas decarbonisation scenarios

Figure 3-12 presents the relevance of the individual actions to the three gas decarbonisation scenarios. **Most actions are highly relevant for all scenarios. This is related to the fact that all three decarbonisation scenarios rely to some extent on the main renewable gases** deployed in the scenarios: biogas, biomethane and hydrogen. Thus, while some actions only (or mainly) affect biogas/biomethane or hydrogen, they affect all decarbonisation scenarios (to different extents).

Figure 3-12 Relevance of the actions to the gas decarbonisation scenarios



The main differences are noted in the action sets 2 (Gas market design and integration) and 3 (Support and requirements for renewable and low-carbon gas production and/or consumption). The reduced reliance of the REN-Hydrogen scenario on methane gases in the 2050 horizon (although they are still important in the 2040 horizon) means it is affected by for example policy 2a) “Further integrate the Baltic Regional Gas Market”, but to a lower extent. Likewise, the fact that in the REN-Methane and Cost Minimal scenarios hydrogen is deployed only locally means that those scenarios are affected by measures focusing on hydrogen, but to a lower extent.

In contrast, action sets 1) “Governance of the gas system decarbonisation”, 4) “Infrastructure planning” and 5) “Energy and carbon taxation” have a significant impact on all scenarios. This is logical, as those sets do not specifically focus on methane or hydrogen gases, but instead are transversal, aiming to provide the appropriate signals and regulatory conditions to all stakeholders to deploy the most efficient solutions to decarbonise the gas system.

Hence, almost all actions proposed are required in order to fully and cost-efficiently decarbonise the Baltic Regional Gas Market, regardless of the specific choices that policymakers and stakeholders will make regarding e.g. the extent of biomethane and hydrogen use in the different end-use sectors, and whether dedicated hydrogen networks at the national or regional levels will be deployed. **Therefore, these actions can be considered no-regret actions.** The exceptions are mainly actions 2c) “Measures to develop a liquid hydrogen market” and 3c) “Consider a legal ban on connecting new buildings / new gas boilers”. Depending on the extent of the role of hydrogen in the region’s energy system, creating a liquid hydrogen market may not be fully feasible as hydrogen production and use may remain localised, at least in the short- to medium-term. And while we recommend policymakers to consider a legal ban on building connections to the fossil gas grid and/or on installing new fossil gas boilers, it may be possible to decarbonise the gas system without this measure, as long as other measures are sufficiently effective and appropriate signals are provided to stakeholders.

An important choice that national governments should make concerns the development of a dedicated hydrogen network at the national and regional level. As discussed, the three decarbonisation scenarios all make use of the main renewable gas types (biogas, biomethane, hydrogen). However, the scenarios are strongly differentiated by whether a dedicated hydrogen network is deployed in the 2040-2050 timeframe, with only the REN-Hydrogen scenario considering such a network. This has an impact on the relative importance of hydrogen in the future energy system, as well as the relevance of many actions in the present plan, particularly 2c (Measures to develop a liquid hydrogen/derivatives market in the long-term) and 4c (Review and harmonisation of gas quality standards, in what concerns hydrogen gas quality).

Implementation responsibility and channels

National ministries bear the main responsibility for implementation of the proposed measures, often jointly with NRAs. Network operators (TSOs and sometimes DSOs) should also be frequently involved, but the final decisions on those policies should remain with policymakers and regulators. The main exception concerns action 4c) “Review and harmonise gas quality standards where appropriate”, where TSOs are logically the best placed to agree on harmonised gas quality standards (with the involvement of and possibly a mandate from policymakers/regulators).

This responsibility is reflected in the main implementation channels, illustrated in Figure 3-13, where national energy sector, renewable energy or taxation legislation form the main channels for the proposed actions, and for which ministries are the main executive body responsible regarding amendments. In addition to this, regional cooperation initiatives will be important especially from the overall governance and infrastructure planning point of view. Decisions from the energy regulators will be an important channel to implement many actions, and particularly those dealing with the gas market design and infrastructure planning. Finally, TSOs should lead the development of new harmonised gas standards to implement action 4c.

Figure 3-13 Implementation channels for the actions to decarbonise the gas system of the Baltic states and Finland

	Energy sector legislation	Regional cooperation initiatives	Renewable energy legislation	Regulatory decisions	Gas quality standards	Energy & carbon tax. legislation
1) Governance structure	X	X				
2a) BRGM integration	X			X		
2b) Energy certification system	X					
2c) Liquid hydrogen market	X					
3a) Support for biogas/biomethane			X			
3b) Support for hydrogen						
3c) Ban on new connections/boilers	X		X			
4a) Infra. planning coordination	X	X		X		
4b) Connection req. and planning				X		
4c) Gas quality standards					X	
5a) Energy excise taxes						X
5b) Carbon taxation						X

4 Project challenges and lessons learned

4.1 Project challenges

The table below presents the main challenges the project team faced during the development of the deliverables, detailing what occurred and how the project team dealt with the challenges.

Challenge 1: Delays in the finalisation of Deliverable 2

The original timeline of the project foresaw the submission of Deliverable 2 at the end of June 2022. The final version of deliverable was however submitted in September 2022 (with 3 months delay), due to among other factors discussions on the scope of the project. This has impacted the timeline of the rest of the project and subsequent deliverables.

Challenge 2: Developments in the gas market situation impacting the project results

The project was launched in March 2022, shortly after the Russian invasion of Ukraine which has had significant impacts on the EU energy markets and prices. The developments and effects of the war and subsequent energy crises on the Baltic Regional Gas Market could not all be taken into consideration given the time limits of the study as well as data availability. Therefore, the project team has included in this final report (Deliverable 8) a section on the updated gas market situation since 2022 which aims to present what has (and what has not) been considered in this study; as such, indicating the limits of the project results.

Challenge 3: Complexity in dealing with the feedback received from stakeholders for Deliverable 7

From July 2023 to August 2023, a stakeholder consultation was launched to receive feedback on the results of the previous deliverables (Deliverables 4 to 6) as well as relevant input to develop the action plan (Deliverable 7). Some stakeholders questioned the assumptions that were used to develop the decarbonisation scenarios (in Deliverables 2 and 3); given among others the recent developments in the gas market situation. However, these decarbonisation scenarios had already been presented earlier to stakeholders which had the opportunity to provide their feedback in June 2022. The project team did not adapt the decarbonisation scenarios but provided individual responses to these stakeholders, committing to include a section in the final report that would lay out these recent developments and their potential impact on the study results.

Challenge 4: Regional focus of the action plan

As it was agreed during the project that the analysis should cover the whole Baltic Regional Gas Market, the actions proposed in the plan of Deliverable 8 needed to have a regional focus. However, at the same time many of the activities addressed by the proposed actions are currently conducted at the national level, which provides a clear room for improvement regarding regional coordination, but also required an assessment of the national contexts before the actions could be drafted. The team has addressed this issue by reviewing the national, regional and EU contexts for each of the individual actions (sections “why is the action required?” and “current status” of each action description in Deliverable 8). This ensured that the actions proposed complement any on-going initiatives as well as address clearly identified regulatory gaps.

4.2 Lessons learned

In this section, recommendations and lessons learned are presented to provide insights for the European Commission and the beneficiaries:

- **Sustained collaboration between the four Member States is key to implement the action plan** – Given the action plan aims for further integration of the Baltic Regional Gas Market and focuses on actions to be taken at the regional level, it is key that the governments of the four Member States continue to work together in the implementation of the proposed action plan.
- **Adequate capacity within the national authorities will be critical for the successful decarbonisation of the Baltic Regional Gas Market** – Most actions proposed in Deliverable 8 are rather complex. Furthermore, national ministries and energy regulators should bear the main responsibility for implementing most of the actions. Hence, ensuring national authorities have sufficient human resources with the appropriate skills will be critical for the successful implementation of the plan.
- **It is difficult to predict future shocks on the energy market** – The decarbonisation scenarios have been developed based on assumptions derived from the gas market situation in 2022. Recent geopolitical developments (i.e. Russian war in Ukraine and associated energy crises) have shown that the market situation can change quickly and that potential impact of shocks cannot always be predicted. The risk assessment conducted in Deliverable 5 aims to allow the beneficiaries to consider potential shocks that could have an impact on the evolution of decarbonisation scenarios in the future and prepare eventual mitigation policies.

Annex A – Updated communication material

Project description

Gas Decarbonisation Pathways

The project provided the European Commission's DG Reform and the national governments of Estonia, Latvia, Lithuania and Finland with recommendations for the development of actions, including new legislation, for decarbonising the Baltic Regional Gas Market by 2050.

Despite decreasing in the last years, natural gas consumption remains an important source of greenhouse gas emissions in the region. Fossil gas demand must be further reduced and substituted by renewable and low-carbon gases if the region is to achieve net full decarbonisation by 2050 as well as reduce its exposure to high gas prices and external supply shocks.

The project conducted four main activities:

- Modelling of three pathways for decarbonising the Baltic Regional Gas Market by 2050 leveraging biogas, biomethane and hydrogen;
- Assessment of energy system and macro-economic impacts of the decarbonisation pathways;
- Identification of main risks for achieving the pathways;
- Proposal of a regulatory action plan for achieving the decarbonisation pathways.

The action plan identifies clear measures in five categories (governance, market design, public support, infrastructure planning and energy & carbon taxation) which will support national authorities, gas network operators and other actors ensuring the optimal solutions for decarbonisation the regional gas system are deployed.

This project is funded by the European Union via the Technical Support Instrument and implemented by Trinomics B.V., in association with the Stockholm Environment Institute and E3-Modelling between February 2022 and December 2023, in cooperation with the European Commission.

Social media text

Post 1

The Gas Decarbonisation Pathways project for the Baltic Regional Gas Market is concluded!
Funded by @EU_reforms and implemented by @InfoTrinomics, @SEIreseach and @E3Modelling, it provides an action plan for gas decarbonisation of EE, LV, LT and FI.
We have presented on 3 October the results in the Estonia Gas Market Conference 2023!

[image of action plan]

Post 2

Interested to learn more about decarbonising the gas system of EE, LV, LT and FI?
Check out the final results of the project funded by @EU_reforms and implemented by @InfoTrinomics, @SEIreseach and @E3Modelling.
Reports available here 👉 short url link

[image of action plan]

Visual materials

See separate file.

Annex B - Tables with references to relevant material and documents

Deliverable	Title	Format
Deliverable 1	Inception report	Word/PDF
Deliverable 2	Baseline data collection report	Word/PDF
	Data map	Excel
Deliverable 3	Report on the relevant scenarios for a decarbonised Baltic Regional Gas Market by 2050	Word/PDF
	Energy system modelling outputs	Excel
	Hydrogen pipeline cost estimates	Excel
Deliverable 4	Report on the impact assessment of the scenarios for a decarbonised Baltic Regional Gas Market	Word/PDF
	Socio-economic impact assessment results	Excel
	Average energy cost for household and commercial users	Excel
Deliverable 5	Report on the risk analysis of the scenarios for a decarbonised Baltic Regional Gas Market	Word/PDF
Deliverable 6	Sensitivity analysis of the scenarios for a decarbonised Baltic Regional Gas Market	Word/PDF
	Energy system modelling SA results	Excel
Deliverable 7	Action plan for achieving a decarbonised Baltic Regional Gas Market	Word/PDF
	Stakeholder consultation document	Word/PDF
	Consolidated responses to the stakeholder consultation	Word/PDF
Deliverable 8	Estonia Gas Market Annual Conference 2023 presentation	Powerpoint
	Visual materials	Powerpoint
	Summary figures in Estonian	Powerpoint
	Project photos	jpg

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