Gas decarbonisation pathways for the Baltic Regional Gas Market Countries

João Gorenstein Dedecca (Trinomics)
Javad Keypour (SEI)

Estonia Gas Market Annual Conference 2023
03 October 2023

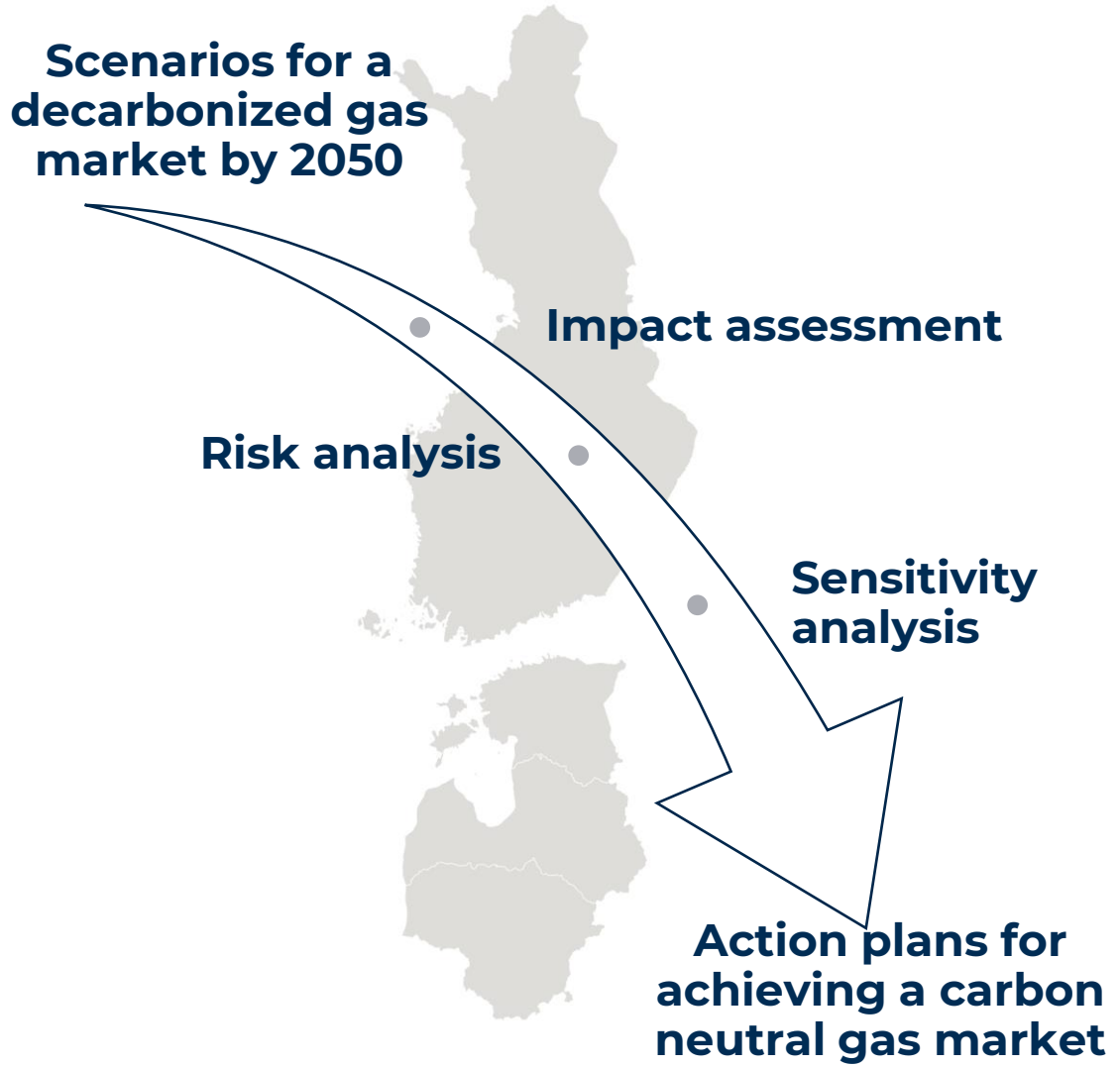
This project is carried out with funding by the European Union via the Structural Reform Support Programme and in cooperation with the Directorate General for Structural Reform Support of the European Commission

www.trinomics.eu

Project introduction

Objective: Provide recommendations for development of new legislative framework for decarbonising the Baltic Regional Gas Market by 2050

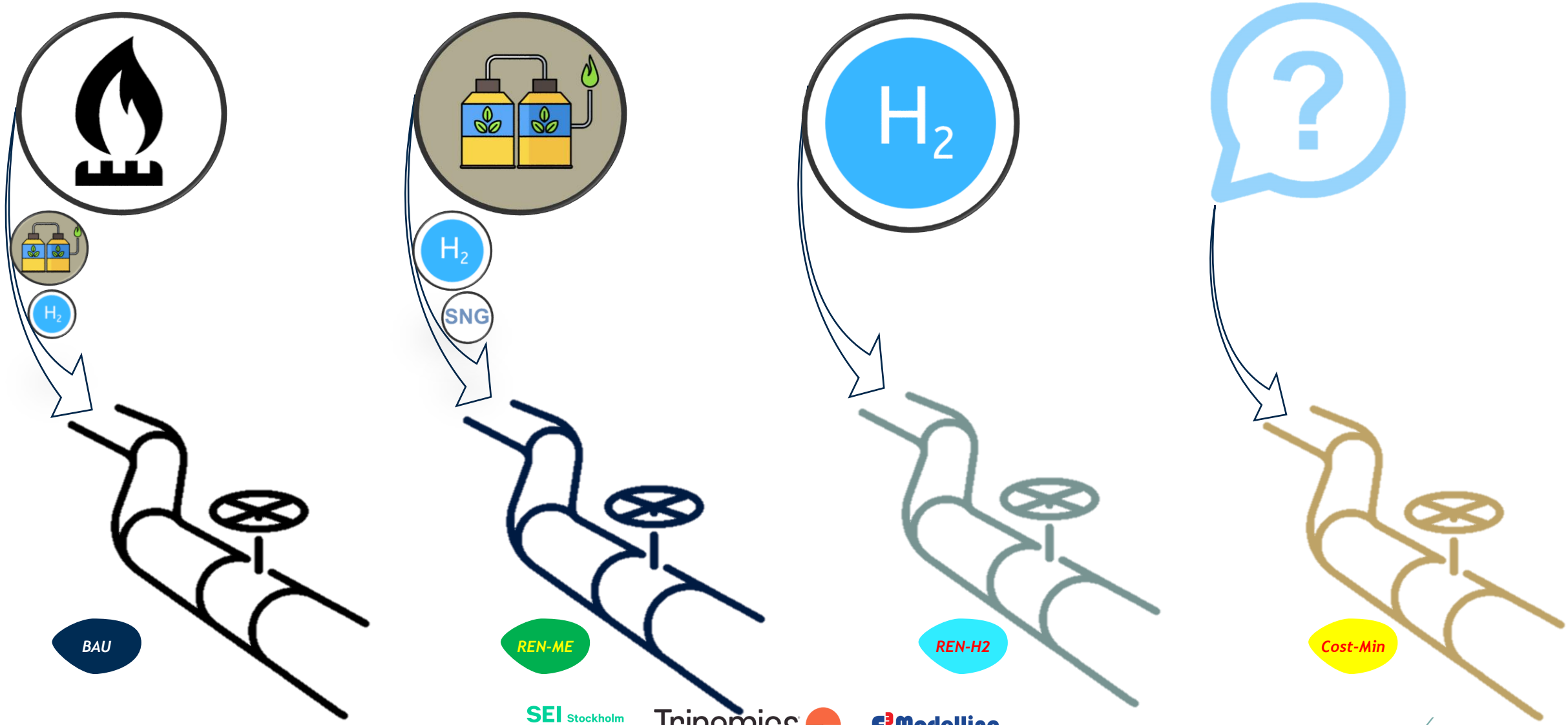
Running from
February 2022 to **October 2023**



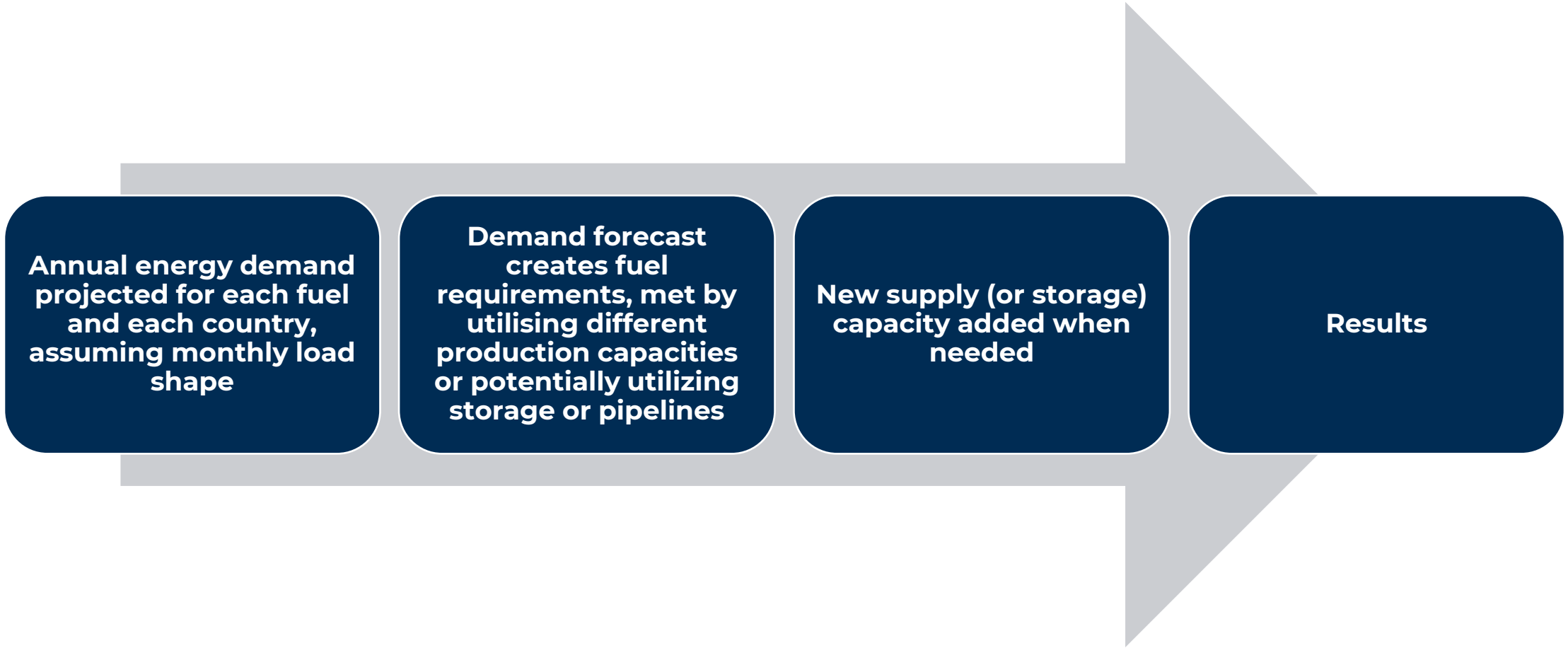
Gas decarbonisation pathways

www.trinomics.eu

Four scenarios of gas decarbonisation in Baltic + Finland market



An overview of modeling steps



Impacts of energy efficiency and direct electrification measures in reducing overall gas demand have been considered in demand projection.

Modelling assumptions

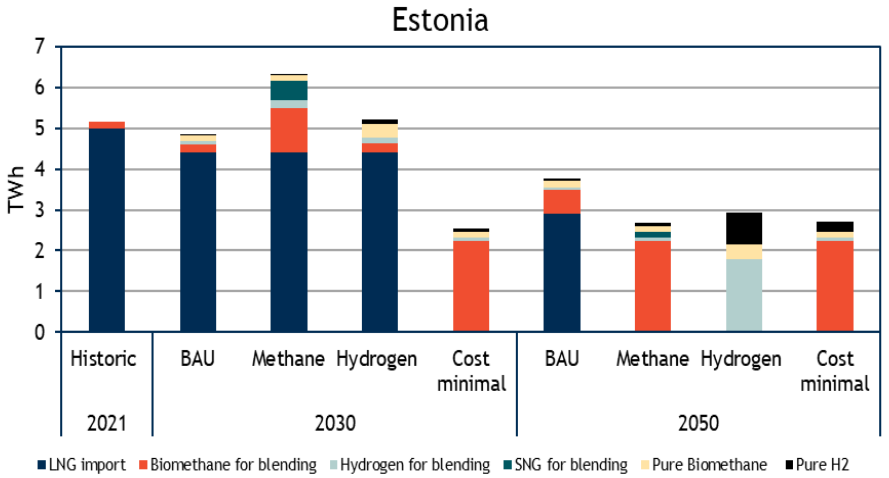
Scenarios	Assumptions of pipeline gas
Business as usual	Hydrogen blending – 5 Vol% Biomethane projections – based on NECP targets NG- Remainder
REN-Methane	Hydrogen blending – 10 Vol% Biomethane projections – reach the maximum economically feasible potential by 2050 NG- phased out gradually by 2050 SNG- Remainder of pipeline mix
REN-Hydrogen	Hydrogen blending – **10 Vol%** until **2040** , **100 vol%** from **2041** Biomethane projections – based on NECP targets NG – phased out by 2040
Cost minimal scenario	Maximum cap Hydrogen – 10 Vol% Biomethane – Maximum potential NG – phased out by 2040 SNG

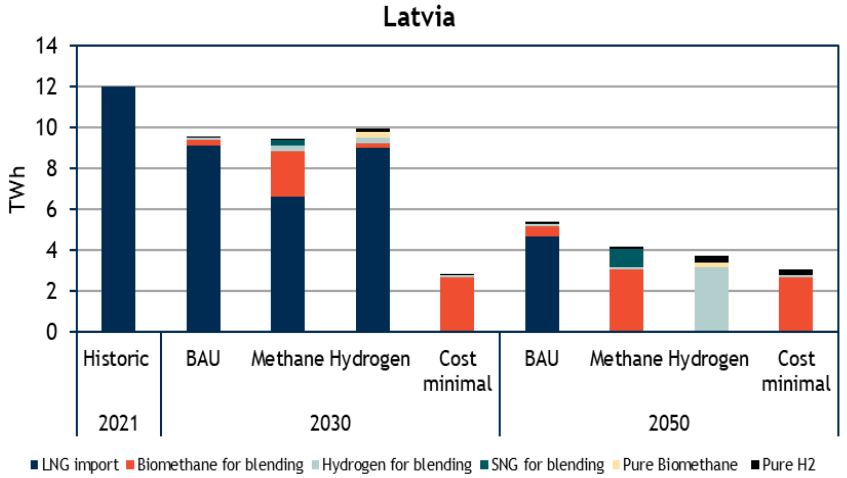
Key findings of gas supply scenario planning

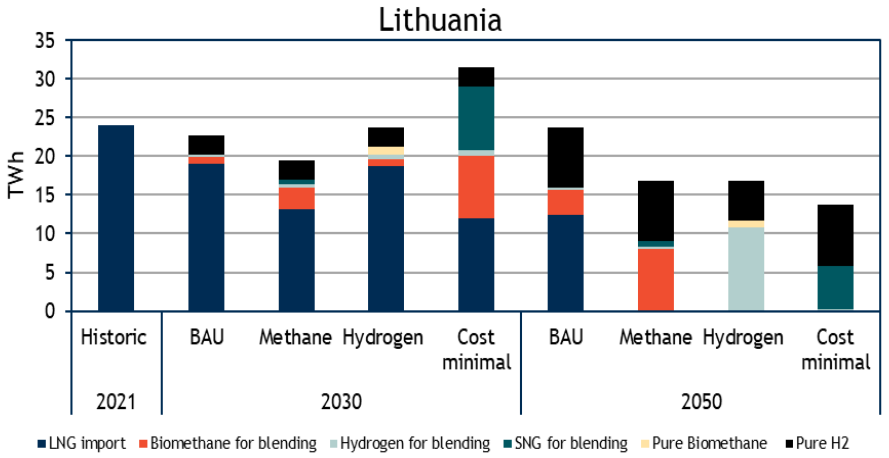
1. **Gas supply will be reduced by 2050, considering the energy efficiency and electrification**

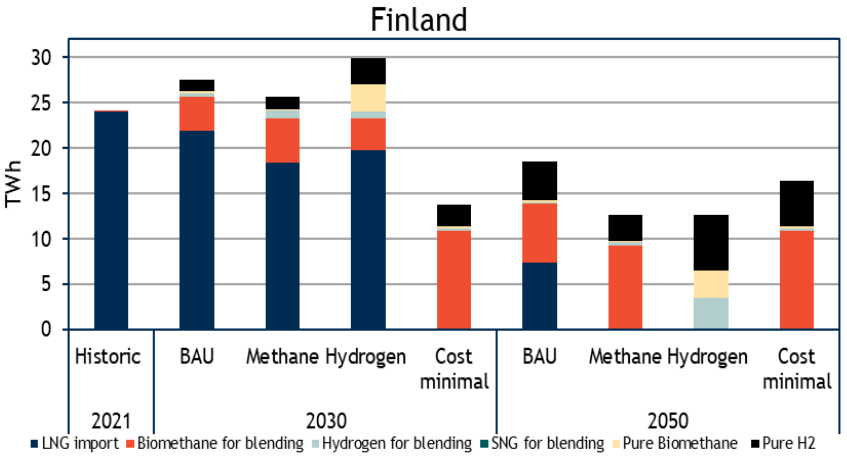
2. **BAU scenario still needs natural gas**

3. **Biomethane surplus can flow across the region and cover regional demand**

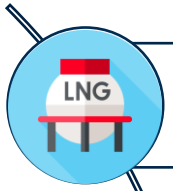




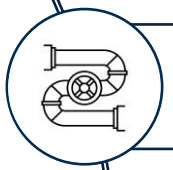




Key findings of gas supply scenario planning



Existing **Klaipeda**, **Inkoo** and planned **Skulte** terminals are sufficient to satisfy the region's **NG demand**; however, the region's LNG import dependency will gradually decrease by 2050.



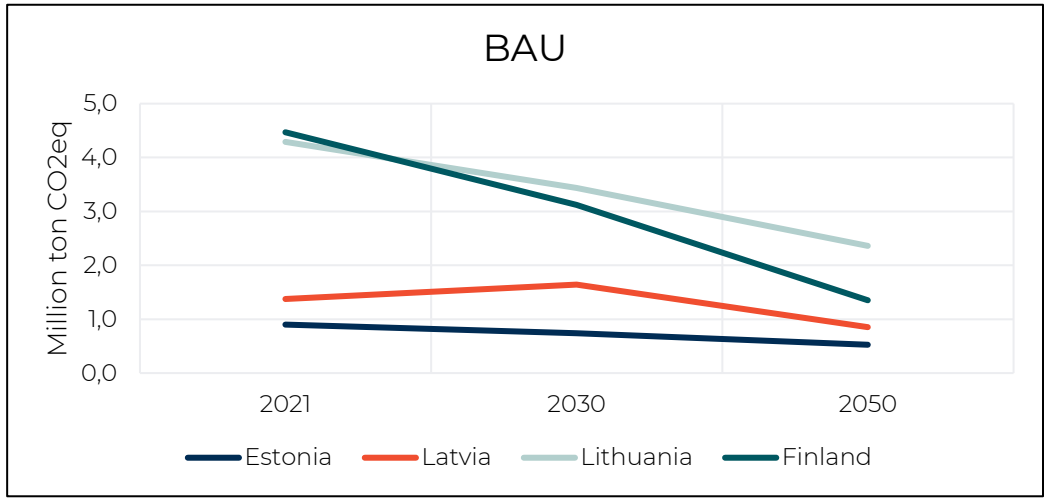
Based on the optimization results, no flow from **GIPL** to the region.

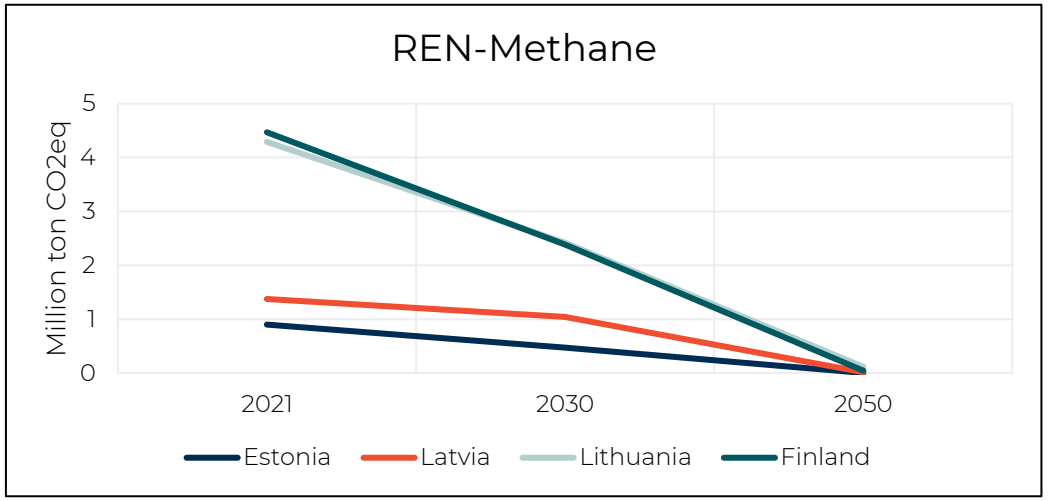
Regional **cross border flows** reduce by 2030 but increase by 2050 as renewable gas is integrated into the regional gas market.

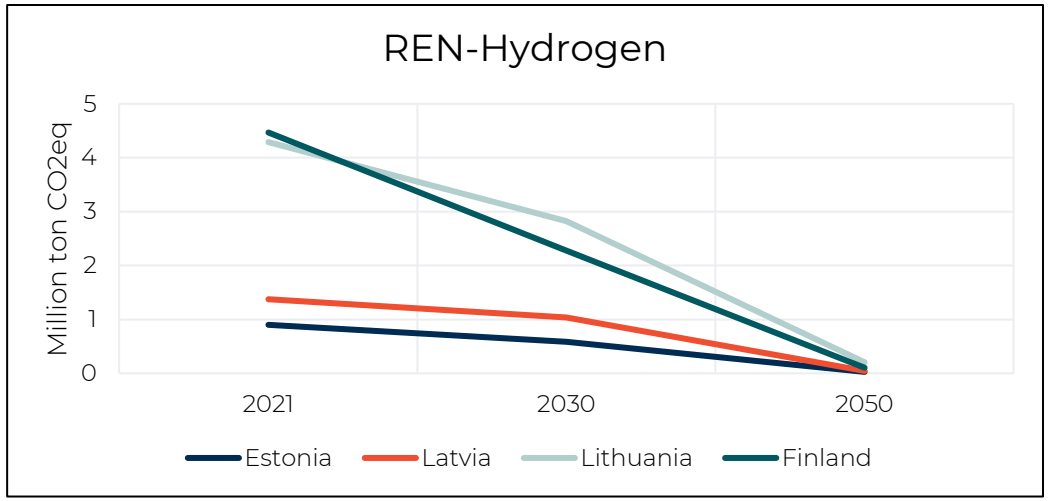
Different utilisation of **Inčukalns** UGS storage in REN-H2 vs REN-Methane/C.M. scenarios.

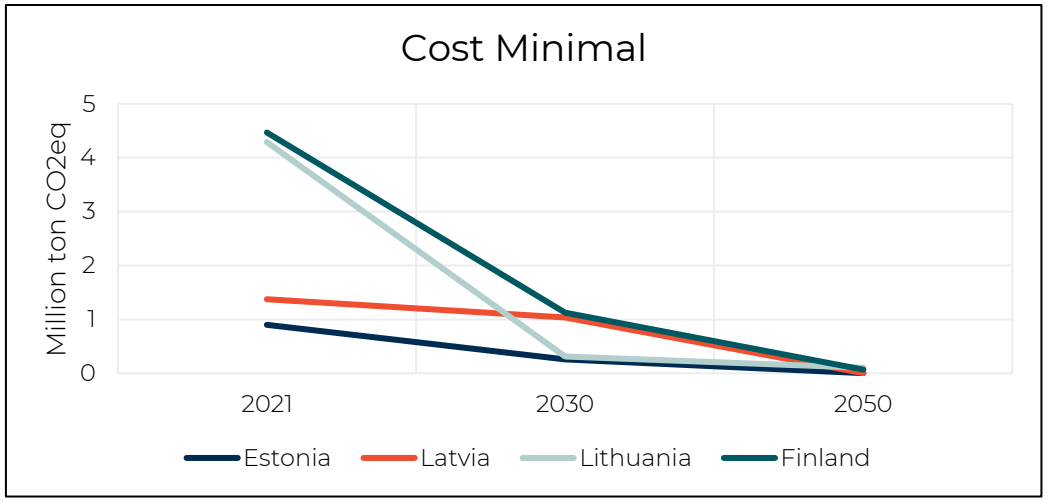
The REN-Hydrogen scenario, benefits lower LCOE-H2 and the REN-Methane has lower LCOE-M.

CM scenario presents the fastest emission reduction







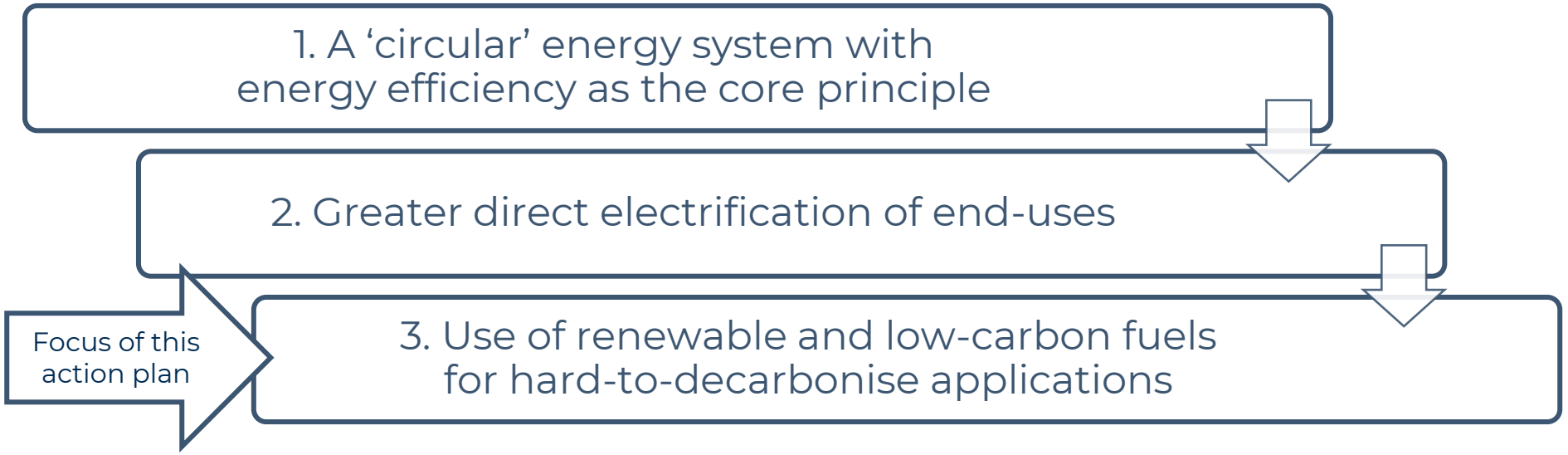


Action plan for decarbonisation of the Baltic Regional Gas Market

www.trinomics.eu

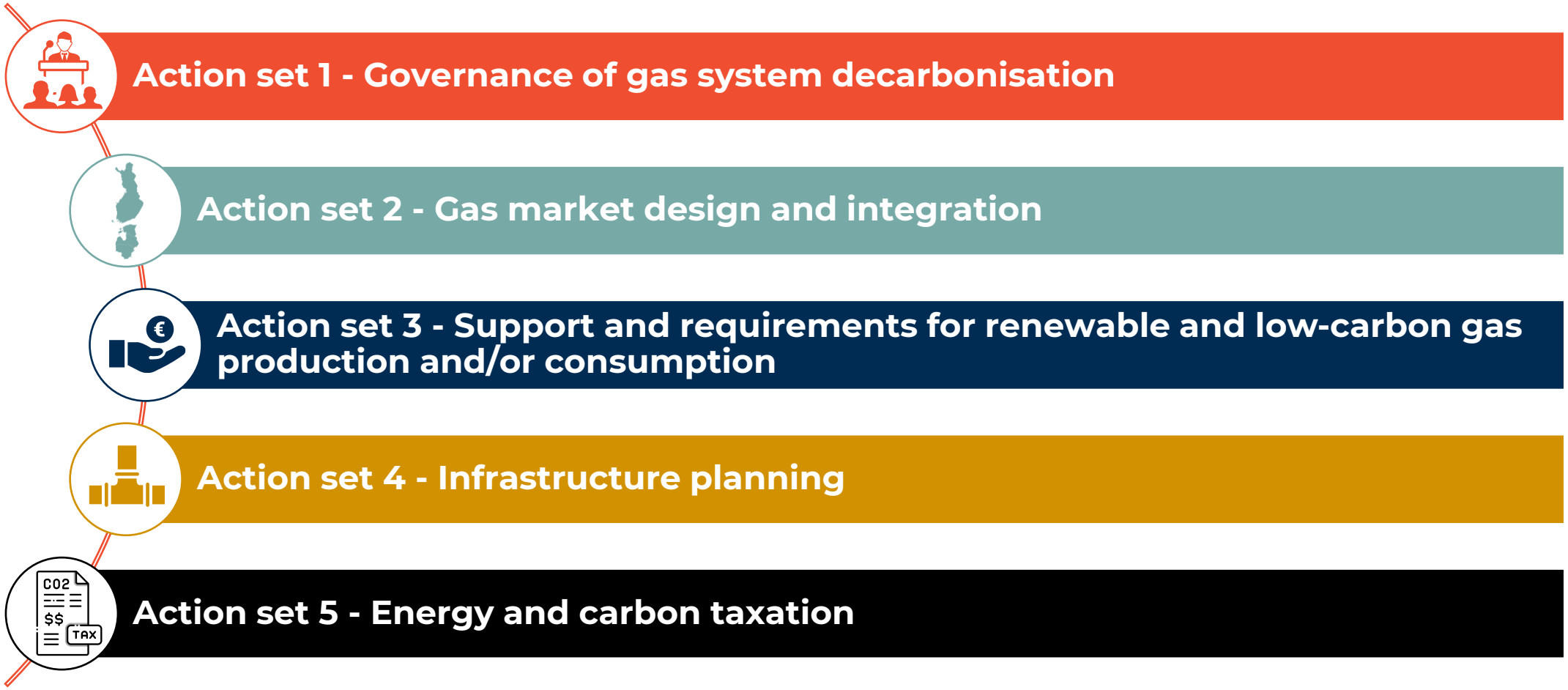
Hierarchy for cost effective decarbonisation

The EU Energy System Integration Strategy highlights that energy policies should follow a hierarchy for cost-effective decarbonisation

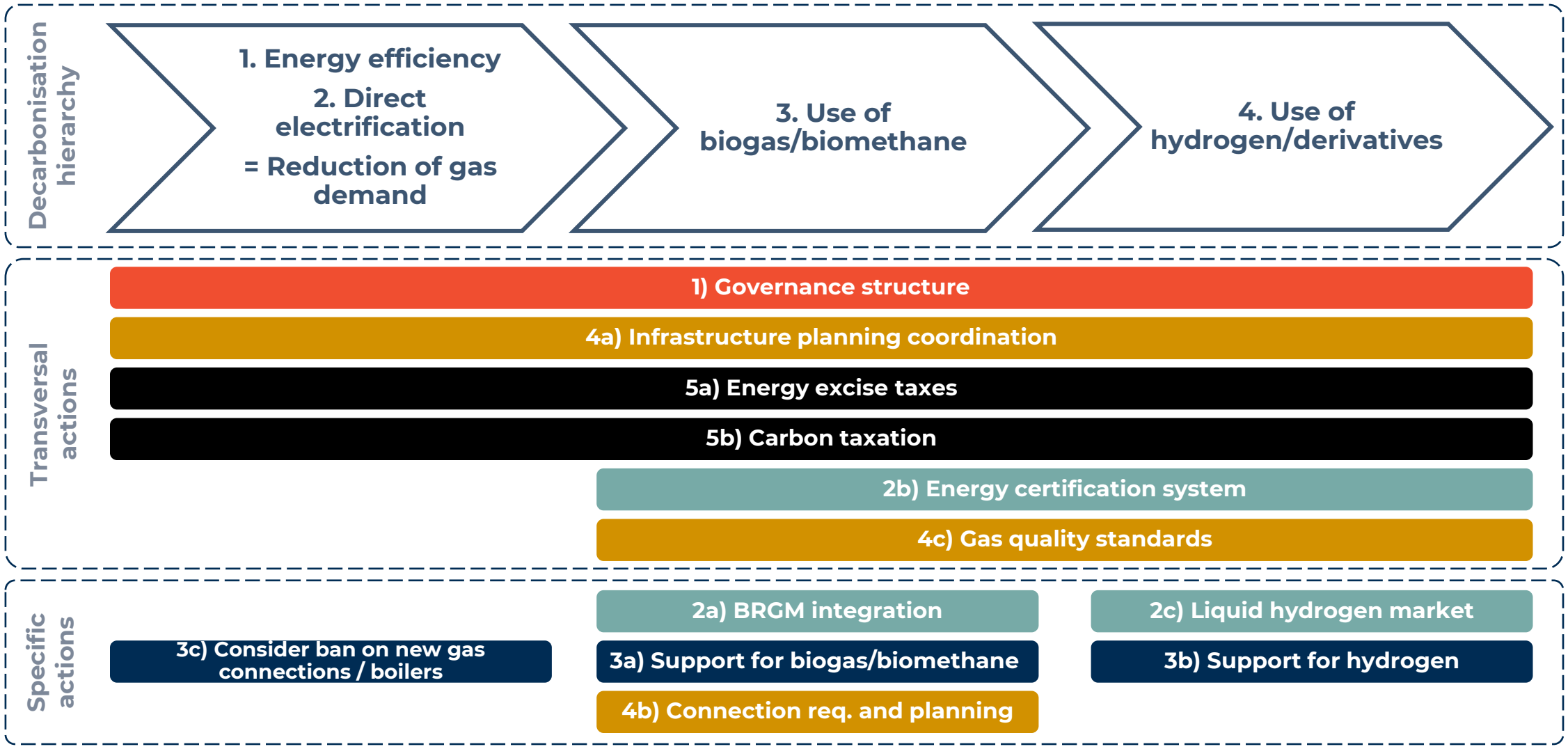


Energy efficiency and direct electrification measures reducing overall gas demand are not included in this action plan but should be prioritised ahead of policies substituting natural gas by renewable and low-carbon gases.

Action sets of the plan



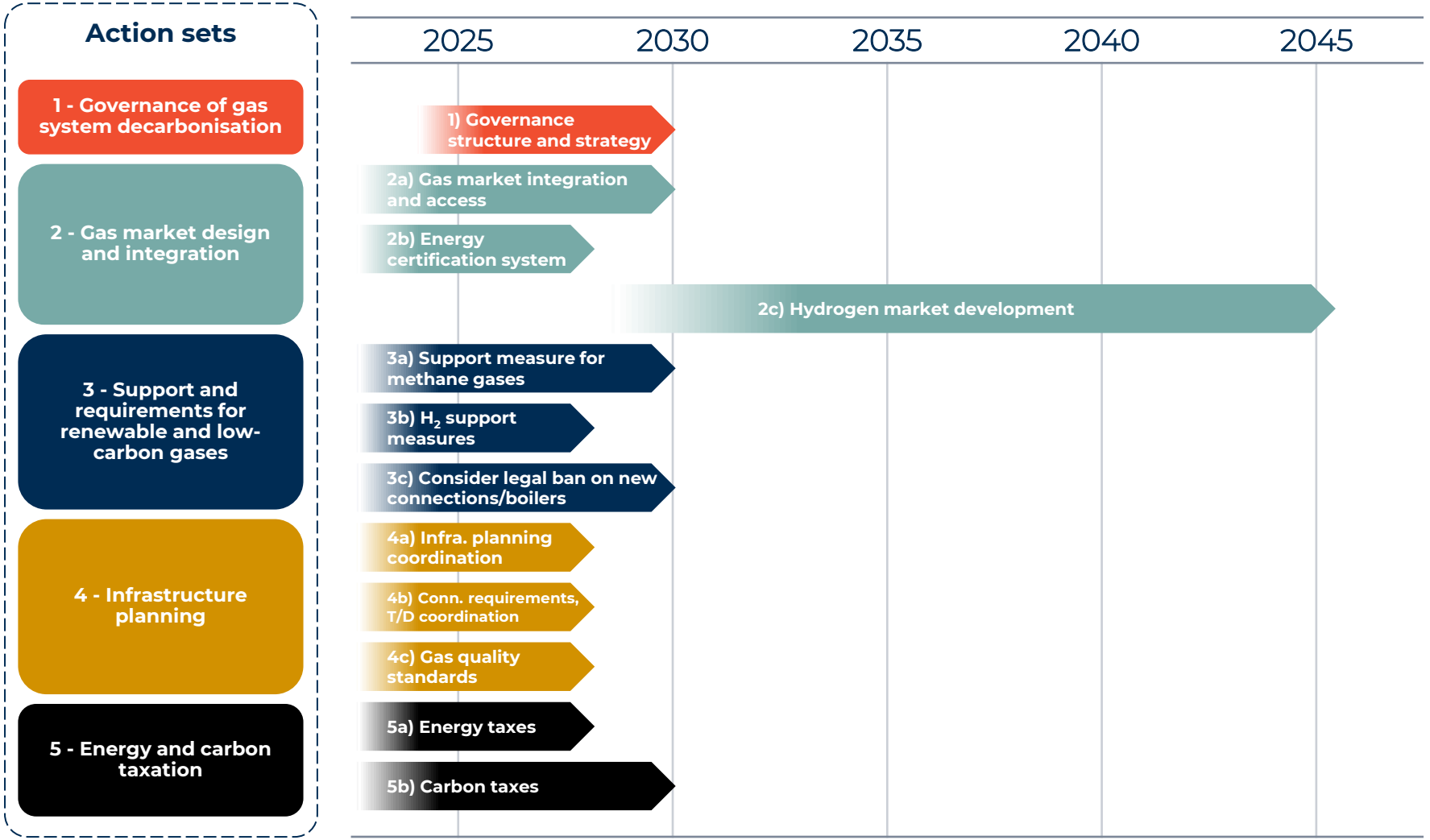
Actions to decarbonise the gas system



Risks addressed

- Significant risks exist for efficiently achieving dec arbonisation of regional gas system
- 7 risks were identified as main ones (out of 16 assessed)
- The action plan addresses all main risks – however, some risks such as related to the macro-economic context and geopolitical events, will require generic policies and actions

Action plan roadmap



Scenarios' costs and public support considerations

Scenario costs

- CAPEX for renewable gas production in three decarbonisation scenarios: ~ 11 B€
- OPEX represents > 90% of total costs, driven by LNG imports
- All decarbonisation scenarios should lead to lower costs to consumers by 2050
  - But attention is needed in the 2030 timeframe

Levelised cost of energy

- Biomethane: could reach 50-60 EUR/MWh by 2050
- Hydrogen: could reach 145-160 EUR/MWh
- High uncertainty: deployment depends on targets, resource availability, LNG, ETS & elec. prices

Policy considerations

- Public cost of most actions rated as low, requiring especially additional human resources
- Energy networks should in principle not be subdisised (except R&D)
- Biogas production & upgrade: (temporary) subsidy could be justified and linked to LNG prices
- Renewable hydrogen production: subsidy necessary to kick-start deployment, but challenging to set level of support

Recommendations to policymakers

- Energy efficiency and direct electrification measures reducing overall gas demand should be prioritized
- Governance, infrastructure planning and energy/carbon taxation measures are no-regret measures and do not depend on the exact pathway
- Policymakers should pay attention to the fact that despite the existence of some actions with low complexity, most are rather complex
- An important choice concerns the development of a dedicated hydrogen network at the national and regional level
- Quick implementation of the actions is paramount for maximising the societal net benefits of decarbonising the region's gas system

Thank you for your attention, please contact us for more information

João Gorenstein Dedecca
joao.dedecca@trinomics.eu

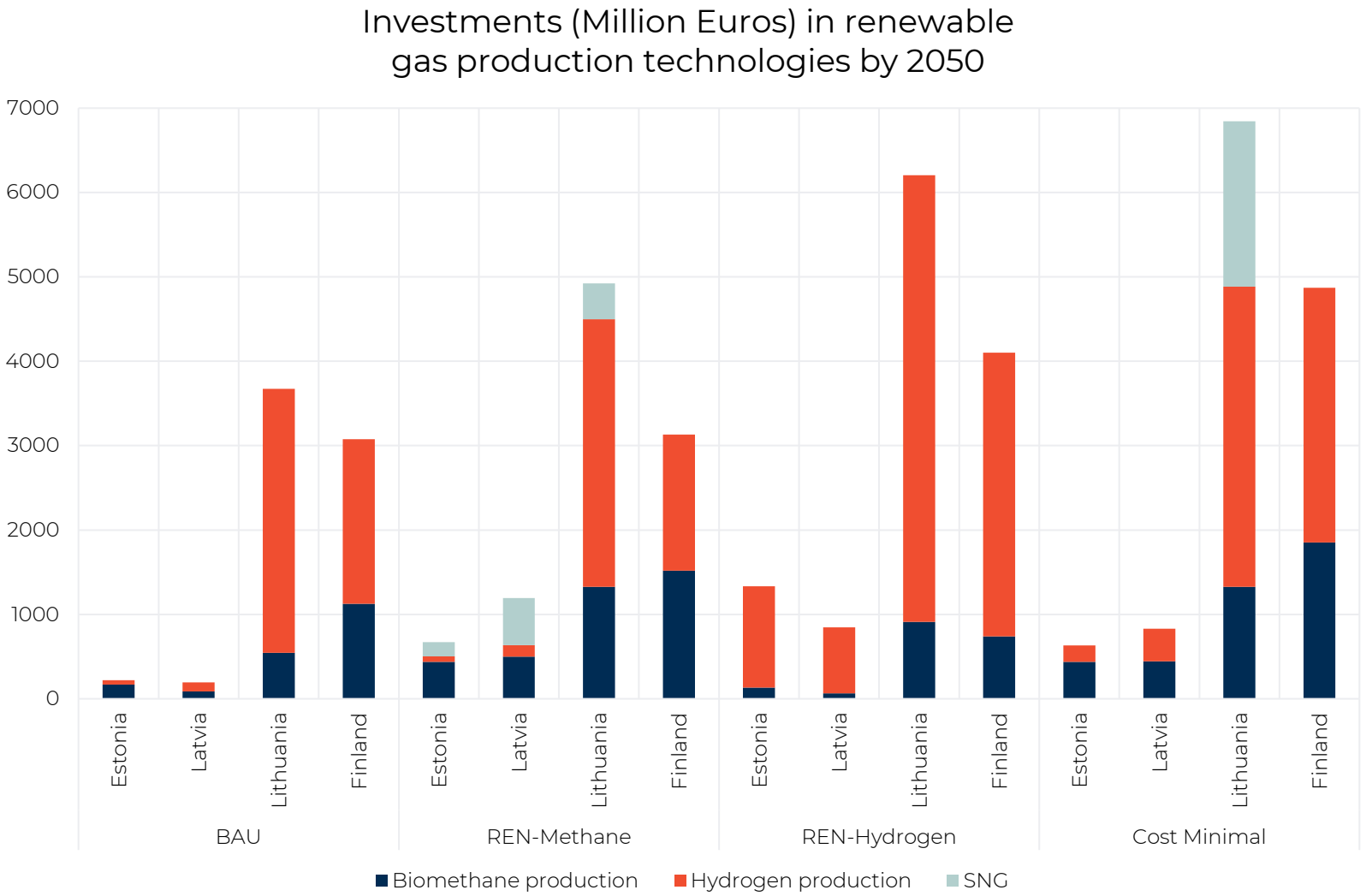
Javad Keypour
javad.keypour@sei.org

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

Back-up

www.trinomics.eu

REN gas production investment - CM Scenario



Pathways details

Indicators	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Scenario definition	'Business-as-usual'	'REN -Methane dominant scenario'	'REN -Hydrogen dominant scenario'	'Cost minimal scenario'
Decarbonisation level	Full gas sector decarbonisation is not achieved	Full gas decarbonisation is achieved		
End-user decisions				
End-user decisions regarding the applications in demand sectors *	Focus on methane-based end-user applications	Focus on methane-based end-user applications	Focus on hydrogen-based end-user applications	Focus on the least cost-based fuel mix (with the hydrogen technical limitation constraints without major investment for retrofitting)
Major gas carrier	NG is still a major part of the gas demand (followed by biomethane and hydrogen and a small portion of biogas)	Methane (includes biomethane and SNG and followed by H_2 and a small portion of biogas)	Hydrogen (followed by a small portion of biomethane and biogas)	
Strategy for the gas infrastructure to follow end-user decisions				
Gas type expected within a national and cross-border gas infrastructure	NG followed by biomethane and hydrogen	Short term: NG followed by biomethane, SNG, and hydrogen Long-term: Biomethane followed by SNG and hydrogen	Short term: NG followed by hydrogen Long term: NG followed by hydrogen and eventually pure hydrogen	Optimised scenario for the least cost solution (with the hydrogen technical limitation constraints without major investment for retrofitting)
Hydrogen blending	Up to 5 vol.%	Up to 10 vol.%	Up to 10 vol.% and eventually 100 vol.% pure hydrogen	
NG infrastructure	No retrofitting on gas supply infrastructure is envisioned	No heavy retrofitting on gas supply infrastructure is envisioned Technical possibilities of biomethane and hydrogen injection in transmission and/or distribution lines are considered.	No heavy retrofitting on gas supply infrastructure is envisioned for blending levels up to 10 vol.% By 2041, total repurposing of the NG grid infrastructure (TSO and DSO lines) is envisioned.	Retrofitting constraints (on the NG grid infrastructure) are envisioned if the hydrogen blending levels cross the threshold of 10 vol.%
End-user equipment adaptation	No retrofitting constraints for end use applications are considered except for the applications where the end equipment is sensitive to the NG gas quality**.**	Retrofitting constraints for end use specific applications.	Retrofitting or replacement constraints for end use specific applications.	Retrofitting constraints for end use specific applications.
Gas supply infrastructure in use	The role of transmission lines remains largely intact. Gas distribution via DSO lines.	The role of transmission lines remains largely intact. Gas distribution via DSO lines.	The role of transmission lines remains largely intact. Gas distribution via DSO lines.	The role of transmission lines remains largely intact. Gas distribution via DSO lines.
Deployment of dedicated gas pipelines by TSO and/or DSO	Limited and separated hydrogen networks may exist. New dedicated pipelines are not modelled but a comparative cost feasibility of pure gas supply modes will be provided in a case study (dedicated pipeline vs. gaseous truck transport)			
Plan for excess hydrogen	No		Hydrogen export potential for Estonia is considered	Hydrogen export potential for Estonia is considered
Plan for excess biomethane	Biomethane potential in each country is conservative and is used only to fulfil the national gas demand.			
Change of demand between scenarios	Baseline demand projections	Gas demand projections with electrification considerations		
Gas storage	Conventional large-scale underground methane storage with an assumption to be able to store blended gas up to 10 vol.% H_2		Conventional large-scale underground methane storage with an assumption to be able to store blended gas up to 10 vol.% H_2 blends. After 2040, surface gas storage options for pure hydrogen.	Conventional large-scale underground methane storage with an assumption to be able to store blended gas up to 10 vol.% H2 blends

Actions of the plan

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

Implementation channels

	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

Relevance to the decarbonisation scenarios