Decarbonisation options of existing thermal power plant burning natural gas

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Abstract. Nowadays power industry faces deepest crises ever with unprecedented prices shocks and climate challenges at the same time. From one hand we realise the need of energy transformation of power industry towards more sustainable future with climate neutral technologies. From the other hand it become obvious that this change could not happen immediately and transition period is needed with some fossil fuel technology still playing an important role as a back-up for renewable energy sources. The biggest question what is the best and cost-efficient way to decarbonise existing thermal power generation. We try to address it on the example of existing combined cycle gas turbine (CCGT) power plant fuelled by natural gas. Clearly the following possible options were identified: 1) replacement of natural gas with alternative gases, such as green hydrogen, bio or synthetic methane, 2) carbon capture and underground storage (CCS) in geological formations, 3) carbon capture, liquefaction and export, 4) carbon capture and utilisation (CCU). US giant General Electric in its publication "Decarbonizing gas turbines through carbon capture" is considering similar options for decarbonising of gas turbines. They divide it into two approaches: 1) pre-combustion by using a zero or carbon neutral fuels, such as hydrogen, synthetic methane, biofuels or ammonia and 2) post-combustion by removing carbon from the plant exhaust, using liquid or solid sorbents or oxy-fuel cycles. In this publication we try to compare these different options, despite they are not clearly comparable. For the analysis we take natural gas fired CCGT plant Riga TPP-2 in Latvia with installed capacity of 881 MW (in condensing mode).

Keywords: carbon capture utilisation and storage (CCUS), green hydrogen, synthetic fuels.

1. Replacement of natural gas with alternative gasses

In order to completely (100 % in energy values) replace natural gas in Riga TPP-2 by green hydrogen, we need electrolizers with capacity of at least 2600 MW, gas compressors, large storage volumes and other equipment. Very roughly this is an investment of at least 2,6 billion EUR for hydrogen production, storage and supply. Additionally, we shall take into account necessary modernisation of CCGT plant to be capable for 100 % hydrogen firing. According to gas turbine manufacturers, CCGT plant does not require any modernisation, if hydrogen share in natural gas-hydrogen mixture does not exceed 5 % (volume). For higher blending of hydrogen, such aspects as higher flame speed (270 cm/s for H_2, 30 cm/s for CH_4), high adiabatic flame temperature, higher flashback risk, lower explosion limit, lower Wobbe index (40.90 MJ/Nm³ for H_2, 48.17 MJ/Nm³ for CH_4), higher volume flowrate (3.3 times higher than for CH_4), lower density (0.09 kg/Nm³ for H_2, 0,717 kg/Nm³ for CH_4). It requires a serious upgrade of gas turbine fuel system (Fig. 1): air and fuel supply systems, compressors, burners, combustion chambers (multi cluster DNL or diffusion combustors), materials, sealings, gas leakage monitoring systems, fire protection, combustion monitoring systems.

The effect of co-firing of the mixture of hydrogen and natural gas on carbon dioxide emissions was studied using the formula, which is used by Latvian Environment, Geology and Meteorology Centre for CO_2 emission calculations:

$$E'_{CO_2} = \frac{C^d \times M_{CO_2} \times 1000}{Q_z^d \times M_C \times 100} \times \rho, \tag{1}$$

where: E'_{CO_2} – CO_2 emission factor (t_{CO2}/TJ), C^d – carbon content of fuel by mass (%), M_{CO_2} – CO_2 molecular weight (44.0098 g/mcl), M_C – C molecular weight (12.011 g/mcl), Q_z^d – lower heating value (LHV) of fuel mixture (GJ/1000m^3), 1000 – conversion from GJ to TJ, 100 – conversion to percentage (%), ρ – density of fuel mixture for transition from volume to mass.

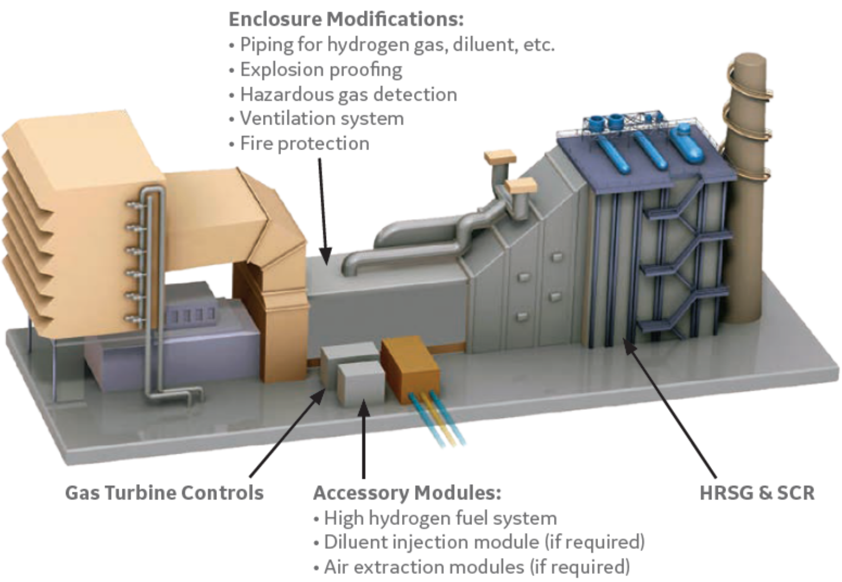


Fig. 1. Potential impact of hydrogen fuel conversion on gas turbine systems

Results of calculations (Table 1) shows gradual reduction of carbon dioxide emission with increasing share of hydrogen in the natural gas and hydrogen blend. The breakthrough in reduction of CO_2 emission is achieved at higher blends (more than 70 %).

Table 1. Reduction of CO_2 emission with increasing share of hydrogen in the fuel mixture

H_2 share in the mixture (%, volume)	**0 %**	**1 %**	**3 %**	**5 %**	**10 %**	**30 %**	**50 %**	**70 %**
H_2 share in the mixture (%, mass)	0.00 %	0.16 %	0.49 %	0.83 %	1.74 %	6.38 %	13.73 %	27.08 %
Density of the mixture (kg/m^3)	0.523	0.518	0.510	0.501	0.479	0.391	0.303	0.215
LHV of the mixture (MJ/nm^3)	34.08	33.84	33.38	32.91	31.75	27.09	22.44	17.78
Emission factor (g[CO_2]/MJ)	41.87	41.74	41.47	41.19	40.45	36.87	31.80	24.07
CO_2 emission reduction (%)	0.0 %	0.3 %	1.0 %	1.6 %	3.4 %	12.0%	24.1%	42.5 %

Production of green hydrogen requires substantial wind and solar resources to supply power to electrolizers. Electrolizers output shall be coordinated with output of wind and solar power, while use of produced hydrogen shall be planned at "Dunkelflaute" (no wind, no sun periods). It means that substantial hydrogen storage capacity shall be ensured.

Depending on CCGT and subsequently electrolizer capacity factor, the amount of necessary renewable resources is determined. For example, in the case capacity factor is 34 %, capacity of on-shore wind shall be 1400 MW, off-shore wind 800 MW and solar power 400 MW to secure work of electrolizers (Table 2).

Conversion efficiency from power to gas is approximately 60 %, while from gas to power – around 55-57 %. Overall conversion efficiency is 33-35 %.

The main advantages of this option: a) possibility for wide use of renewable energy sources (wind and solar) in hydrogen production, b) avoidance of carbon dioxide emissions during the electricity production, c) possibility to supply a surplus of hydrogen to transport sector and industry, d) avoidance of all problems associated with CCS option, including the ban for geological storage of CO_2. The main disadvantages of this option: a) very high costs of hydrogen production, b) very low conversion efficiency, c) necessity to convert CCGT plant for hydrogen combustion and to install considerable wind and solar capacity.

Table 2. Necessary capacity of renewable resources to power electrolizers

Power input, MW	2600	2600	2600	2600
Hours	1000	2000	3000	4000
%	11 %	23 %	34 %	46 %
Power demand of electrolizers, GWh	**2600**	**5200**	**7800**	**10400**
Capacity of RES-E, MW				
On-shore wind	400	1000	1400	1950
Off-shore wind	250	500	800	1000
Solar power	400	200	400	500
Total	**1050**	**1700**	**2600**	**3450**
Production of RES-E, GWh				
On-shore wind	1226	3066	4292	5979
Off-shore wind	986	1971	3154	3942
Solar power	403	201	403	504
Total	**2615**	**5238**	**7849**	**10424**

2. Carbon capture and underground storage (CCS) in geological formations

There are three ways of capturing carbon dioxide emissions from fossil fuel-based power generation or industrial installations (Fig. 2): post-combustion, pre-combustion, and oxy-fuel combustion. Post-combustion methods include chemical absorption, where CO_2 is separated using amine-based absorbent solution or membrane separation, where CO_2 is effectively separated by synthetic membranes made from polymers. Cost of CO_2 capture from coal-fired power plants using amine-based absorption is around 50-100 EUR/t, while membrane technology is cheaper is about 25 EUR/t. Membranes are suitable for low CO_2 concentrations and ensure high purity of CO_2. In pre-combustion methods CO_2 is captured from fuel before combustion by gasifying, oxidising or reforming fuel to produce CO and H_2. In the oxy-fuel method, fuel is burned with pure oxygen, which results in higher concentration of CO_2, which is easier to capture.

The cost of CO_2 capture varies depending on types of power and industrial processes. NGCC (natural gas combined cycle) has the highest cost of carbon capture in power generation. It is approximately 70-120 USD/t or 72-123 EUR/t (Fig. 3).

According to preliminary estimation, the cost of carbon capture for the 881 MW combined cycle power plant could be in the range of 0,7 to 1,2 billion EUR. It could also result in reduction in electric efficiency of the plant from 55 % to 50 % due to high energy demand (steam and electricity) for CO_2 capture.

Storage is the final stage of the CCS value chain and an ultimate way to keep captured CO_2 away from the atmosphere in a permanent manner. In most cases, CO_2 is injected into geological formations such as saline aquifers. Alternatives to aquifers include depleted oil and gas fields, igneous rocks or coal beds (Table 3).

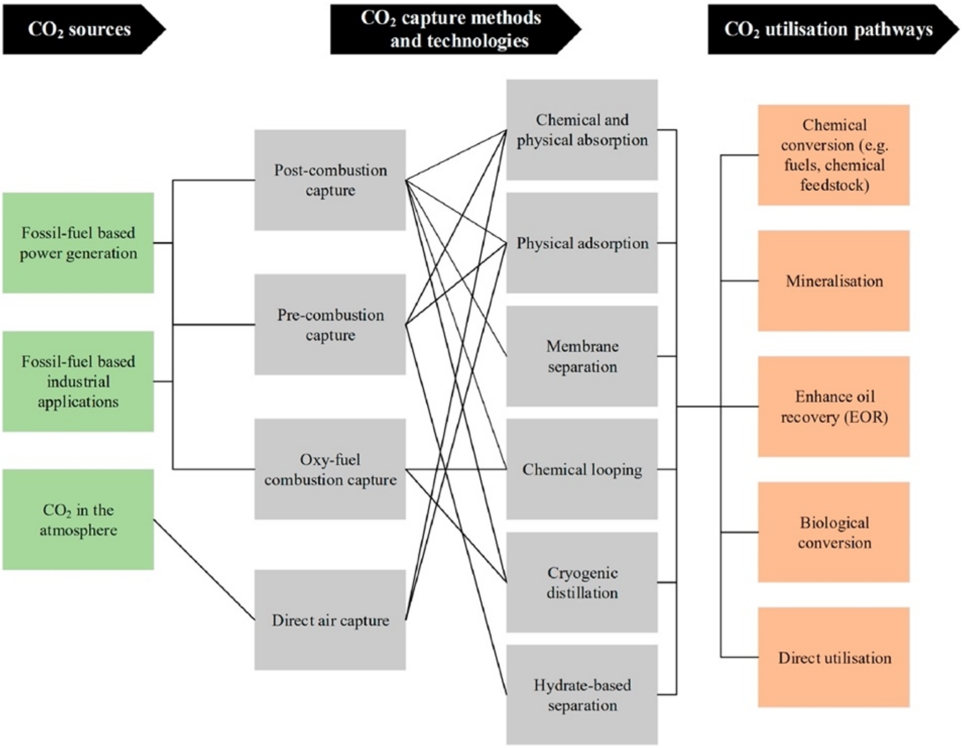


Fig. 2. Different CO_2 capturing and utilisation methods

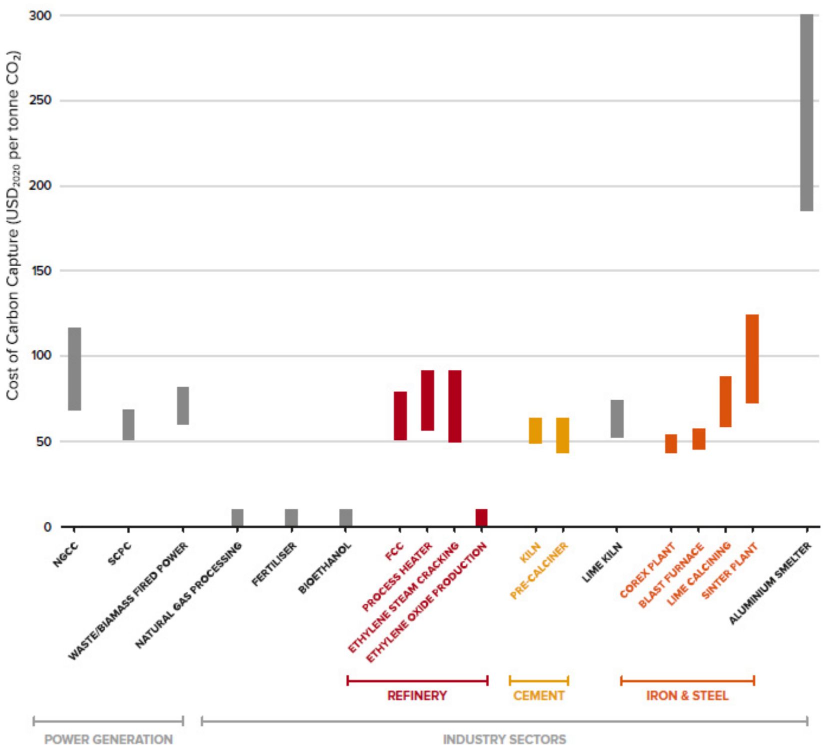


Fig. 3. Cost of carbon capture in various types of power and industrial processes

Table 3. CO_2 permanent storage options

Resource type	Pros and cons	Mechanisms
Saline aquifers	Mature Usually not constrained Requires significant survey work	CO_2 storage as dense phase Displaces brine to other connected formations (plus pressure rise) Dissolution (solution trapping) Entrapment in pores (residual trapping) Reaction to form minerals (mineral trapping)
Depleted O&G reservoirs	Geology usually well understood Pilot & demonstration projects Usually smaller & more constrained Potential for leaks from old wells	Reservoir pressure usually lower: storage as gas Storage mainly by pressurization of the reservoir: transition to dense phase
Basaltic / ultramafic rocks	Rapid mineralization Pilot scale (US, Iceland) Very low permeability Monitoring requires new techniques	CO_2 reacts to form carbonate minerals (within months)
Coal beds	Coal seams have natural fractures and abundant micropores Methane production (enhanced coal bed methane) No active projects (4 completed pilots) Permeability reduces quickly	CO_2 diffuses into micropores and displaces coal-bed methane

When it comes to CO_2 storage, the key to success is to map, model and evaluate the specific site for storage in terms of its ability to contain the required volumes of injected CO_2 in a stable state over centuries and millennia.

The situation with carbon storage is different in countries. There are countries, where the storage of CO_2 is not allowed (Latvia, Lithuania, Slovenia), partly (Estonia up to 100 kt only R&D, Czech Republic up to 1 Mt) or fully allowed (Slovak Republic, Croatia, Romania, Hungary).

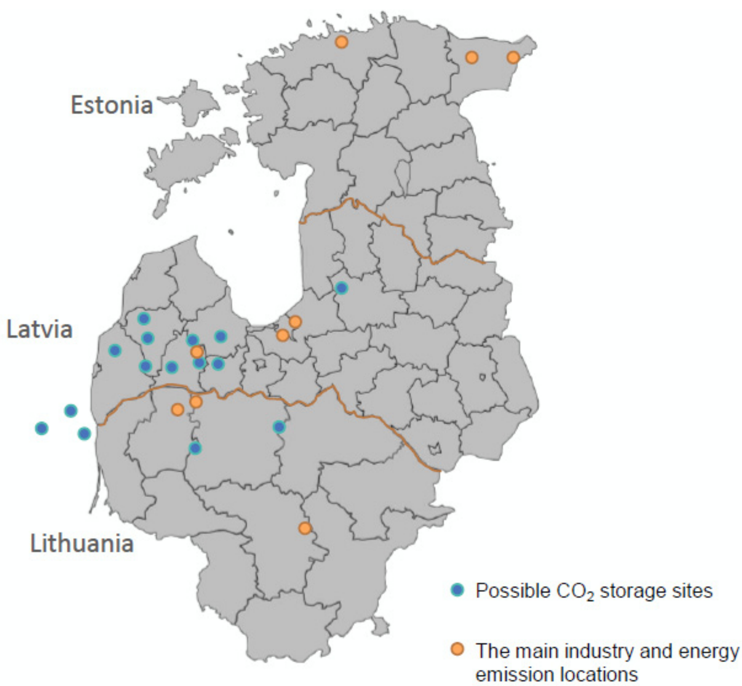


Fig. 4. Baltic states – main energy and industry emission and carbon storage location

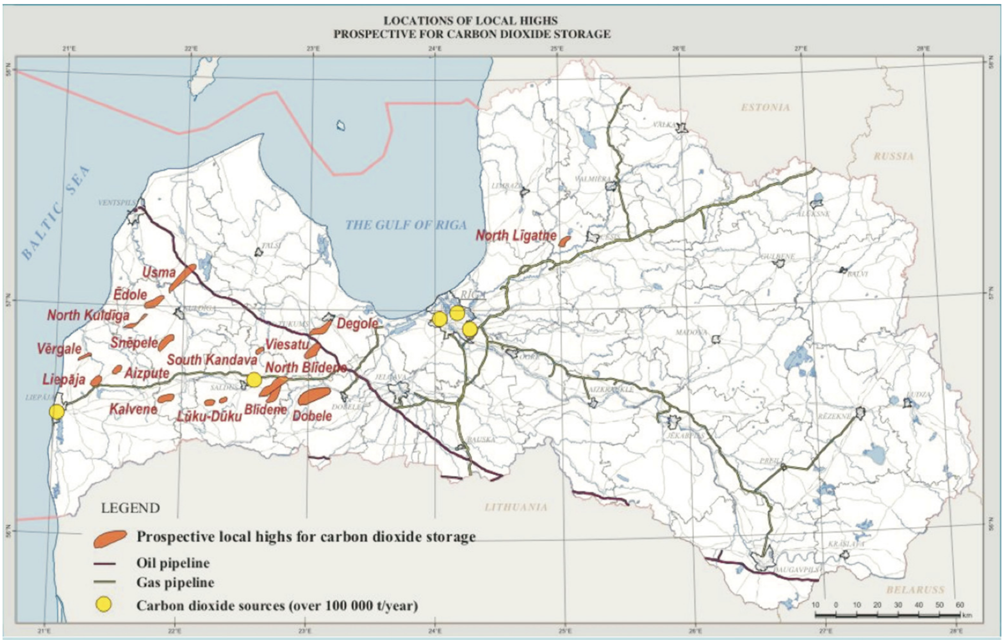
The situation in Baltic States is presented below (Fig. 4):

1) The main industries that make up the most significant part of emissions in Estonia – energy and chemical production; in Latvia – energy production, cement manufacturing; in Lithuania – fertilizer production, oil refining, cement manufacturing.

2) Estonia: CO_2 storage permitted up to 100 kt (R&D only) by low. However, due to the geological formation, Estonia has no geological potential for carbon storage on land or offshore.

3) Latvia: CO_2 storge is not permitted yet, but changes in the Climate act were initiated to permit geological storage of CO_2 in Latvia. Several geological structures (onshore and offshore) have been identified where CO_2 storage would be theoretically possible. However further geological research should be conducted to get more accurate information.

4) Lithuania: CO_2 storage not allowed by low, but Lithuania has identified some potential location for CO_2 storage (depleted oil fields, Vaškai, Syderiai).



Structure	Stratigraphic unit, Formation	Lithology	Top depth (m)	Permeability (mD)	Porosity	CO_2 density (t/ m³)	Storage efficiency factor	Area, km2	Reservoir volume, MMm3	Theoretical capacity, Mt	Capacity, Mt (optimistic values)	Capacity, Mt (conservative values)
Aizpute	M. Cambrian, Deimena Fm.	Sandstone	1120	300	0.21	0.720	0.40	51	587	72.8	31	14
Blidene	M. Cambrian, Deimena Fm.	Sandstone	1168	300	0.21	0.730	0.40	43	2091	259.3	112	58
N.Blidene	M. Cambrian, Deimena Fm.	Sandstone	1041	300	0.21	0.710	0.40	95	2655	329.2	142	74
Degole	M. Cambrian, Deimena Fm.	Sandstone	1094	300	0.21	0.720	0.40	41	782	97.0	41	21
Dobele	M. Cambrian, Deimena Fm.	Sandstone	1058	300	0.22	0.720	0.40	67	2000	248.0	105	56
Edole	M. Cambrian, Deimena Fm.	Sandstone	975	300	0.20	0.720	0.40	19	283	35.1	16	7
Kalvene	M. Cambrian, Deimena Fm.	Sandstone	1133	300	0.22	0.730	0.40	19	525	65.0	27	14
Liepaja	M. Cambrian, Deimena Fm.	Sandstone	1102	300	0.21	0.720	0.40	40	660.0	73.0	31	6
Luku-Duku	M. Cambrian, Deimena Fm.	Sandstone	1024	300	0.22	0.720	0.40	50	1440	179.0	75	40
N. Kuldiga	M. Cambrian, Deimena Fm.	Sandstone	1034	300	0.20	0.720	0.40	18	490	61.0	21	13
N. Ligatne	U.-M. Cambrian, Cirma Strata	Sandstone	700	300	0.22	0.560	0.40	30	810	100.4	41	23
S.Kandava	M. Cambrian, Deimena Fm.	Sandstone	1053	300	0.20	0.720	0.40	69	1573	195.1	82	44
Snepele	M. Cambrian, Deimena Fm.	Sandstone	1067	300	0.22	0.720	0.40	26	602	74.6	31	17
Usma	M. Cambrian, Deimena Fm.	Sandstone	1000	300	0.21	0.710	0.40	20	180	9.0	5	2
Vergale	M. Cambrian, Deimena Fm.	Sandstone	993	300	0.22	0.710	0.40	10	194	24.1	9	5
Viesatu	M. Cambrian, Deimena Fm.	Sandstone	1070	300	0.21	0.720	0.40	19	424	52.6	21	10
										1875.2	790	404

Fig. 5. Potential sites for CO_2 geological storage in Latvia

According to Latvian Environment, Geology and Meteorology Centre evaluation, there is a number of potential sites for CO_2 geological storage in Latvia (Figure 5). The overall volume of CO_2 storage is estimated in the range from 404 to 790 Mt. For CO_2 storage from Riga TPP-2 plant the most suitable locations are Dobele (56-105 Mt), Blidene (58-112 Mt) and North Blidene (74-142 Mt) structures. The transportation of CO_2 is suggested along the newly built pipeline adjusted to existing gas transportation network. The length of pipeline is accordingly 110 km to Dobele and 135 km to Blidene. In case of Dobele it is planned to reactivate and inspect two wells drilled during the exploration aimed at the establishment of underground natural gas storage. In case of Blidene 2 new wells at the dome of the Blidene structure is foreseen. The total cost of implementation of the project was estimated at 88.5 million EUR in case of Dobele and 99.5 million EUR in case of Blidene.

According to Alla Shogenova et al. the total cost of CO_2 transport and storage from Riga TPP-2 to North Blidene is 40 million EUR – total CAPEX and 12.8 – total OPEX.

During the study of Dobele structures for development of underground storage of natural gas in 2010, Danish company COWI, based on SIA "Konsorts" evaluation, has reported the overall cost of establishment of underground gas storage 1,165 billion EUR for 7.7 bcm gas storage and 1.403 billion EUR for 10 bcm. Almost 75 % of these costs are attributed to acquisition of cushion gas, 10 % – for wells drilling works, ~6 % – for technological equipment (filters, compressors) and ~7 % – for construction and assembling works, 2 % – others costs, including land acquisition.

The main advantages of this option: a) avoidance of carbon dioxide emissions during the electricity production, b) possibility to store CO_2 emissions, if CO_2 utilisation is not possible in full extend, c) possibility to develop national or regional infrastructure for CO_2 transportation and storage in Latvia, which would be shared among different stakeholders

The main disadvantages of this option: a) existing ban for geological storage of CO_2 and uncertainty with future legislation, b) necessity to make full scale geological investigation to validate the suitability for storage site, c) very high costs of carbon capture, d) uncertainty on how to deliver CO_2 from the plant to storage site.

3. Carbon capture, liquefaction and export

Safely and reliably transporting CO_2 from where it is captured to a storage site is an important stage in the carbon capture and storage (CCS) process. Transport of CO_2 occurs daily in many parts of the world however, significant investment in transportation infrastructure is required to enable large-scale deployment.

Pipelines today operate as a mature market technology and are the most common method for transporting CO_2. Gaseous CO_2 is typically compressed to a pressure above 8 MPa. CO_2 also can be transported as a liquid in ships, road or rail tankers that carry CO_2 in insulated tanks at a temperature well below ambient, and at much lower pressures.

The first long-distance CO_2 pipeline came into operation in the early 1970s. In the United States, over 2,500 km of pipeline transports more than 40 Mt of CO_2 per year from natural and anthropogenic sources, mainly to sites in Texas, where the CO_2 is injected into existing oil fields. The process is well-known as "enhanced oil recovery" (EOR) – the addition of CO_2 increases the overall pressure of an oil reservoir, forcing the oil towards production wells.

The CO_2 shipping chain starts after the CO_2 capture and lasts until storage (Fig. 6). The chain involves liquefaction, buffer storage, loading/unloading, shipping transport and reconditioning. In practice, the CO_2 could be transported under different transport conditions (temperature and pressure).

For Riga TPP-2 one of the possible options could be transportation of CO_2 to the port of Riga (the area of Kundziņsala) through the 25-30 km long CO_2 pipeline, CO_2 liquefaction, loading to CO_2 transport ships and transporting it to the final disposal area, for example, to depleted oil and gas fields in the Northern Sea. For example, such CO_2 storage area is developed by Equinor, Shell and TotalEnergies in the Norwegian shelf, the project is known as Northern Lights. Phase 1 includes capacity to transport, inject and store up to 1.5 million tonnes of CO_2 per year. At the later stage, the storage capacity could be substantially increased.

During the evaluation of liquefied natural gas (LNG) terminal construction in Riga the possible pipeline route for natural gas supply to gas transmission network was identified (Fig. 7). The same route with minor changes could be considered for CO_2 transport to the port CO_2 export facilities.

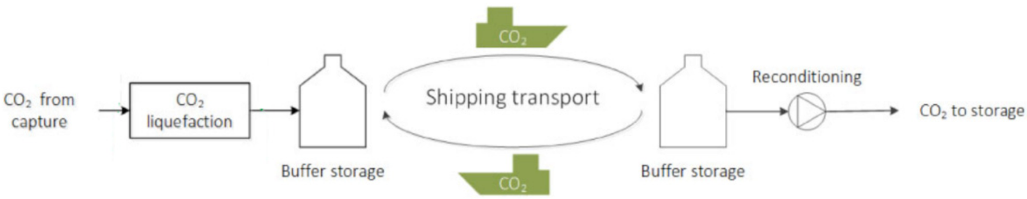


Fig. 6. The components of the CO_2 shipping chain

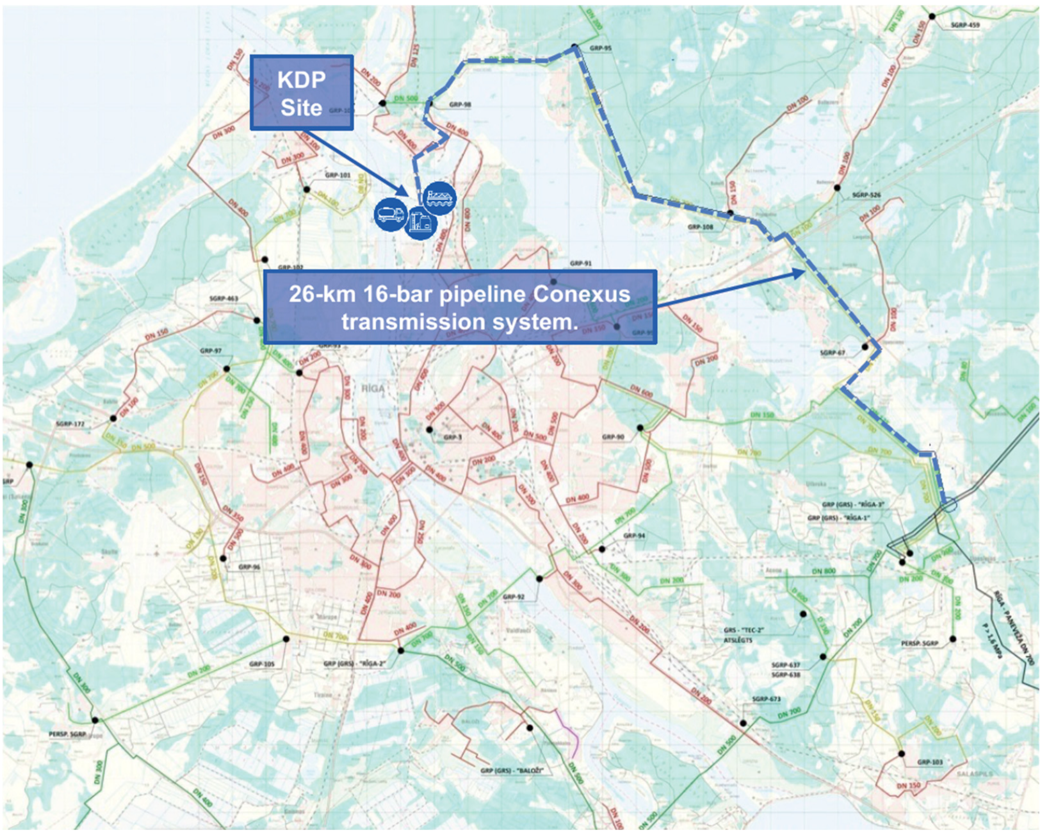


Fig. 7. Possible route of CO_2 transport from Riga TPP-2 to Kundziņsala in the port of Riga

Table 4 presents (on the example of cement industry), that the cost of carbon capture is a part of total CCS costs. In this case (on the example of cement industry) the CO_2 capture cost is approximately 33-50 % from total costs of CCS. The total costs are estimated 75-180 EUR/t. In addition to carbon capture cost it includes compression or liquefaction cost, transportation cost (both pipeline and by ship), cost of CO_2 injection and geological storage and cost of monitoring geological storage.

Table 4. Value chain components of CCS with cost ranges

Value chain components	Estimated cost range / € per t
Carbon capture (cement kiln)	50-90
Carbon compression and dehydration	10-20
CO_2 transport pipeline (150-300 km)	5-25
CO_2 transport by ship (150-1500 km)	15-20
CO_2 injection and geological storage	5-20
Monitoring of geological storage	5
Total	75-180

Current CCS total costs exceed the price of CO_2. According to Fig. 8 the current CO_2 price is equal to the total CSS costs, which include capture, transportation, compression/liquefaction, buffer terminal cost without transportation cost to sink and storage cost, which are part of total CSS costs. That is why European grants and funding are to support CSS project.

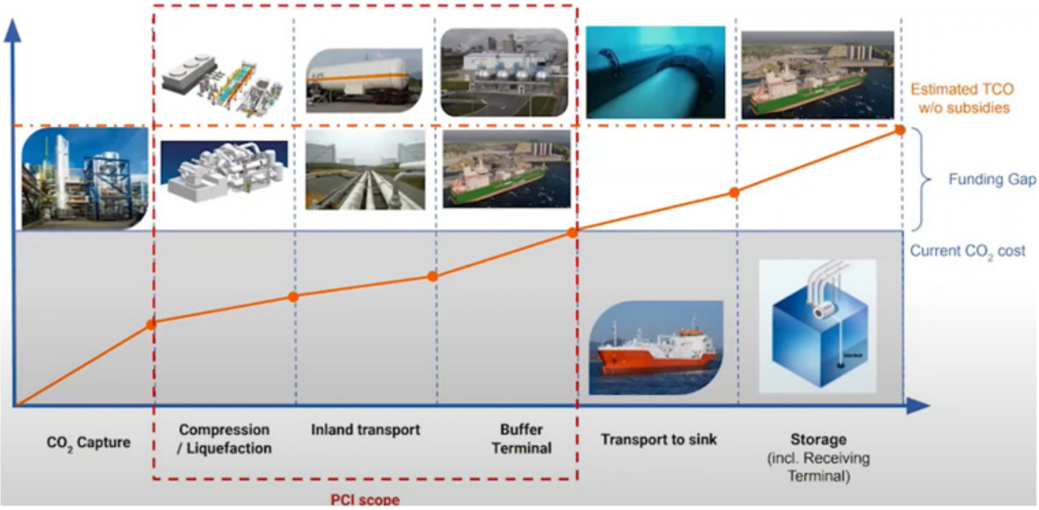


Fig. 8. The costs of CCS value chain (TCO – total cost of ownership)

The main advantages of this option: a) avoidance of carbon dioxide emissions during the electricity production, b) not necessary to look for storage location in Latvia, c) flexibility to balance CO_2 storage and utilisation strategies.

The main disadvantages of this option: a) expansive CO_2 liquefaction and maritime transportation, b) uncertainty with storage capacity and availability of CO_2 storage site overseas, c) very high costs of carbon capture, d) uncertainty on how to deliver CO_2 from the plant to the CO_2 export terminal in the port.

4. Carbon capture and utilization (CCU)

The range of potential CO_2 use applications is very large and includes direct use, by which CO_2 is not chemically altered (non-conversion) and the use of CO_2 by transformation (via multiple chemical and biological processes) to fuels, chemicals and building materials (conversion) (Fig. 9).

For example, from conversion branch, SNG (synthetic natural gas) is natural gas's green relative and is produced by converting carbon dioxide and green hydrogen into methane in a process called methanation. Therefore, SNG can be converted into liquefied natural gas (LNG) and compressed natural gas (CNG) in the same way as natural gas. Thanks to SNG composition, it can be mixed and used interchangeably with natural gas in all applications. Liquefied or compressed SNG can be transported or stored in the gas grid.

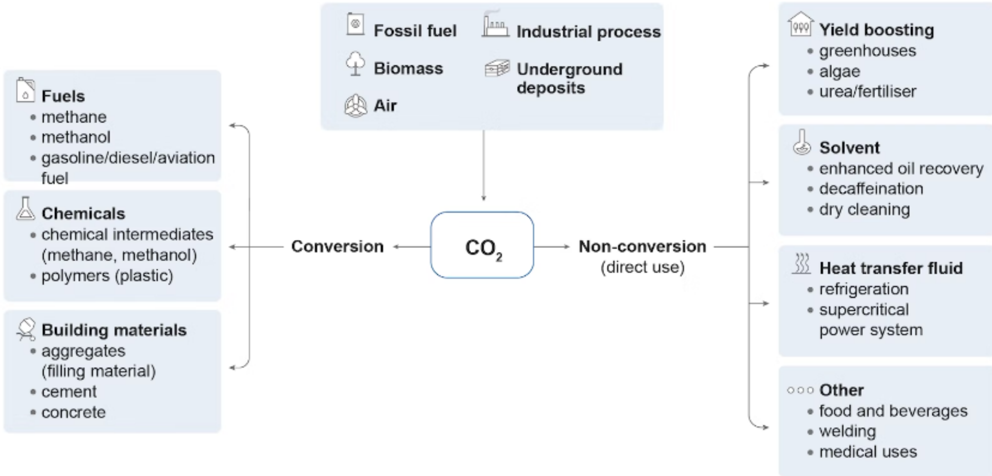


Fig. 9. The options of CO_2 utilization

At this moment it is very difficult to evaluate how big investments could be necessary for CCU project. Some indicative figures show the CAPEX and OPEX for some power-to-X processes: 1) Methanation: 1200 EUR/kW CAPEX, 42 EUR/kW OPEX, 2) Power to liquid via the methanol route 1000 EUR/kW CAPEX, 50 EUR/kW OPEX, 3) Power to liquid via the Fischer Tropsch route 1555 EUR/kW CAPEX, 55 EUR/kW OPEX.

AS "Latvenergo" in cooperation with Latvian Hydrogen Association is developing the pilot project concept for production and use of hydrogen. The concept envisages the mixing of hydrogen and methane: up to 5 % – for the combustion of the mixture in gas turbines, up to 2 % – for injection into the gas grid, the supply of H_2 to external customers (transport, industry) and the use of H_2 for synthetic fuel production in Latvia.

The scope of the project includes RES electricity generation (130 MW wind and 70 MW solar PV), electrolysis equipment (25 MW PEM) for production of green hydrogen, equipment for hydrogen compression and storage, equipment for mixing of hydrogen with methane, hydrogen supply equipment (H_2 cylinders and trailers) for distribution and 3-5 multi-filling stations (Fig. 10).

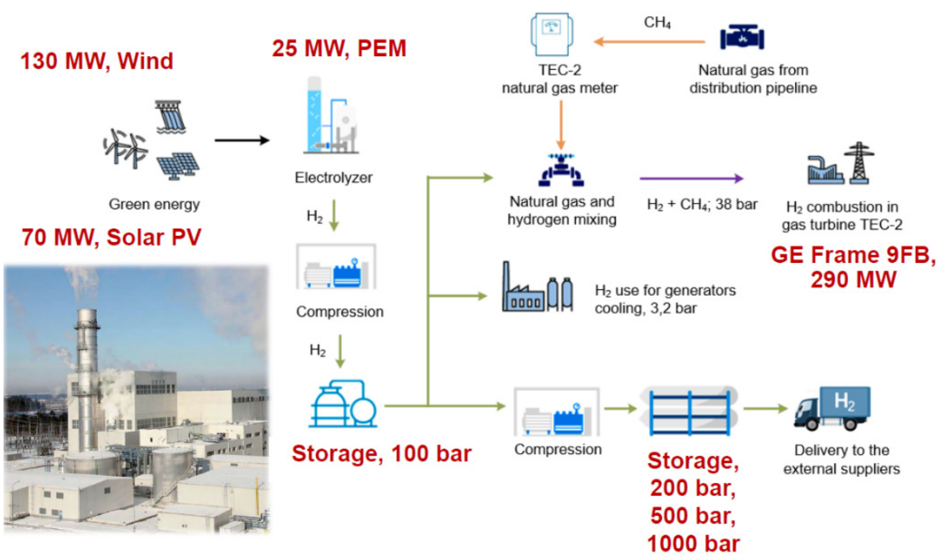


Fig. 10. Concept and scale of hydrogen project (Riga TPP-2)
(Photo of the power plant courtesy of Latvenergo AS)

In summer of 2021, AS "Latvenergo" cooperation was initiated with the Latvian cement producer SCHWENK Latvija SIA and SIA Ventspils naftas termināls on CO_2 capture, storage and use (CCUS) technologies, including hydrogen and synthetic fuel production. On 24 January 2022 mentioned partners received the invitation from Tallinn University of Technology (TTU) and Kaunas University of Technology (KTU) to apply to the European Commission's "Horizon" call HORIZON-CL5-2022-D3-01 (Decarbonising industry with CCUS) in order to implement the research project "CCUS Baltics".

Within the scope of this study it was planned to implement CCUS demonstration as following:

1) AS "Latvenergo" in cooperation with the Latvian Hydrogen Association installs a PEM electrolyzer in Riga TPP-2 within the above mentioned pilot project.

2) CO_2 delivery to the pilot project is provided from the Achemas Grupa factory in Lithuania, for example using the railway infrastructure or road transport.

3) As part of the "CCUS Baltics" project, AS "Latvenergo" install equipment for the production of synthetic fuel (for example, methanol) at Riga TPP-2 production plant.

4) Test injections of CO_2 are made by Conexus on the site of Incukalns underground gas storage.

The main advantages of this option: a) possibility to sell CO_2 for direct use (non-conversion), b) possibility to use CO_2 (via multiple chemical and biological processes) to produce synthetic fuels, chemicals and building materials, c) synergy with green hydrogen production.

The main disadvantages of this option: a) very high costs of carbon capture, b) necessity to deliver sufficient amounts of hydrogen or nitrogen, c) necessity to install complicated and expensive equipment for hydrocarbon synthesis.

5. Overview of latest development in the Baltic states concerning CCU and CCS

According to latest developments in the Baltic states concerning CCU and CCS:

Estonia: CCS technologies will be included in the Environment Development plan 2030 as a measure to mitigate climate effects in Estonia. The limited potential of CCS and the current macroeconomic situation has put a stop to any planning and development of CCS implementation. Stakeholders slowly follow the recent development, but no concrete actions are taken or planned.

Latvia: Climate law is being developed in Latvia – in the current draft, it is planned to abolish the current prohibition on the storage of CO_2, determine the basic principles for this field and delegate further of the regulatory framework. Interaction between stakeholders is going in various formats. The CO_2 capture technology pilot project has been implemented at Schwenk Latvia.

Lithuania: is still considering CCS technologies as one of the tools in combating climate change and moving toward sustainability. Stakeholders are looking for solutions regarding the transportation of captured CO_2 abroad.

6. Conclusions

1) It becomes obvious that every considered option has its benefits and drawbacks, that is why no single answer, which options is preferred does exist.

2) Most likely the right approach would be using the combination of options for decarbonising of CCGT plant, which would definitely include carbon capture, storage and utilisation.

3) Geological storage option depends on the removal of existing prohibition of this option in Latvian legislation and on results of geological investigation.

4) The option with liquefaction and export is less preferred, but could be considered if ban for geological storage in Latvia could not be removed.

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Data availability

The datasets generated during and/or analyzed during the current study are available from the corresponding author on reasonable request.

Conflict of interest

The authors declare that they have no conflict of interest.

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