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Abstract

The main aim of the ELEGANCY project is to accelerate the deployment of Carbon Capture and Sequestration (CCS) technologies in Europe through H_2-CCS chain networks. Five country case studies are included as part of WP5. This report focuses on the Norwegian case study, presenting results on optimal production sites for hydrogen production in Norway when accounting for domestic hydrogen demands as well as export to Germany in accordance with the needs identified in the German case study.

The hydrogen production for export from Norway is to a large extent decoupled from the production for satisfying a potential domestic demand in Norway due to the significantly larger volume of hydrogen. Hence, the domestic demand plays only a minor role for locating the production facilities for export. It is in general cheaper to produce in Norway due to the reduced costs for the transport network to transport CO_2 from Germany. Transport costs play only a minor role in the levelized cost of hydrogen for export to Germany (due to the large demand and economy of scale) but are significant for satisfying domestic demand.

The hydrogen production facilities are clustered around Kollsnes/Mongstad and Kårstø due to the availability of natural gas and the location close to both CO_2 storage and the hydrogen demand locations. Reusing existing pipelines like Europipe may not result in significant cost savings in the levelized costs of hydrogen but may result in reduced costs at the beginning of developing the hydrogen-CCS infrastructure.

Synergies between CO_2 transport and storage from hydrogen production with CO_2 originating from industry may result in the development of CO_2 hubs around the different hydrogen production facilities in Norway. However, the location of the receiving hub of this additional CO_2 should be close to the hydrogen production sites to unlock synergies.

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1 INTRODUCTION

The main aim of the ELEGANCY project is to accelerate the deployment of Carbon Capture and Sequestration (CCS) technologies in Europe through H_2-CCS chain networks. Five country case studies are included as part of WP5. This deliverable presents the results of the Norwegian case study H_2-CCS value chain activities. The key questions for the Norwegian case study are:

1. Where should the production in Norway be located to satisfy industrial demand and demand in the offshore oil and gas industry for decarbonizing its production?
2. What is the impact of exporting hydrogen to Germany on the location of hydrogen production facilities in Norway?
3. How does reusing the existing, extensive natural gas pipeline network affect the costs of hydrogen for the export market?
4. Are there direct synergies between a hydrogen-CCS chain and the development of a Norwegian CCS infrastructure?
5. Can hydrogen production from natural gas with carbon capture kickstart the development of storage of industrial CO_2?

To answer these questions, the value chain tool developed in ELEGANCY Work Package 4 by Imperial College London was used with different scenarios. These scenarios focus partly on all hydrogen demands present in Norway south of Nordland, only the export of hydrogen to Germany, or only the hydrogen demand of the offshore industry in the Norwegian sea.

2 MODELLING APPROACH AND DATA UTILIZED

2.1 Used tool and modifications of the tool

The investigation was conducted using the value chain tool developed in ELEGANCY Work Package 4 by Imperial College London. The tool is described in ELEGANCY Deliverable D4.5.1 [1]. As a short recapitulation, the key features are listed below:

- The GIS interface creates a regular grid on top of the investigated region. The number of grid cells can be specified by the user of the tool.
- The tool uses the centre point of each cell for the calculation of the distance between the neighbouring cells. This implies that each node of the model corresponds to the centre point of a grid cell. This holds also in the case of cells that are not squares. Correspondingly, it may seem that certain production facilities are in the sea while they should be located onshore.
- Hydrogen demand within each cell is aggregated.
- Production technologies (ATR, electrolysis, and comparable) are given in a resolution per grid cell.
- Transmission of hydrogen and CO_2 is only possible to neighbouring cells.

Figure 1 illustrates the concept of grid cells for an excerpt of the Vestlandet region in Norway. The centroids of each grid cell are used for the calculation of the distance between the different cells. Here, it is not possible to transport e.g. CO_2 directly from cell 6 to cell 4. Instead, it would be necessary to transport the CO_2 first to cell 5.

Figure 1: Illustration of grid cells located in Vestlandet with center points of the individual grid cells.

While several case studies could use directly the integrated chain tool developed at Imperial College London and described in D4.5.1, modifications were required for the Norwegian case study especially due to the geographical situation of Norway. Indeed, as a result of the large hydrogen demand offshore and in Germany, i.e. across the North Sea, , the tool was modified to include the possibility to construct offshore pipelines and ship transport between different areas. Furthermore, effort has also been put in incorporating data and costs representative of Norwegian conditions.

Overall, the following modifications were included:

- Hydrogen and CO_2 ship transport were included.
- Hydrogen offshore pipelines were included.
- Offshore pipelines and ship transport require a harbour/landfall with associated costs. As each pipeline requires its own costs and the harbour size and cost depends on both the distance between the transport points and the transport amount, individual resources were included for each pipeline and ship transport size to avoid wrong configurations. Pipeline landfalls also include the compression cost.

- CO_2 cannot be stored directly from Germany on the Norwegian continental shelf. Hence, it is required to transport the CO_2 first to the Norwegian coast before it can be stored on the continental shelf. This is achieved via a blocking of certain cells (close to the German landfall) for certain transport technologies (CO_2 pipelines which may store CO_2 directly on the shelf).
- Supply to offshore installations does not include the costs for a riser, as the demand in each cell is aggregated and it is not possible to say, how many risers may be required. However, risers are included as technologies with very low costs for conversion of the individual transport resources to a single resource.
- The tool allows now for time varying costs for natural gas and electricity and includes different cost regions (e.g. Germany and Norway).
- Certain constraints were removed as they are not relevant for the Norwegian case study.
- Onshore grid cells were differentiated between coastal grid cells and inland grid cells. For example, cells 3 and 6 in Figure 1 are inland grid cells while cells 2 and 5 are coastal grid cells.

2.2 General assumptions

The following general assumptions are conducted in the analysis:

- Full cells have an edge length of 125 km while smaller cells may differ as cells are not necessarily squares. This corresponds to 48 cells in case of the major analysis.
- Investments can be conducted every 5 years and the capacity is available from the first year. This corresponds to an investment horizon of 5 years.
- Individual years are modelled within an investment period to account for a potential ramp up of demand inside an investment period. If the demand is ramped up, it is specifically written in the individual scenario analysis
- A discount ratio of 8 %/a is used for the investment into technologies.
- The investment costs of a technology are equally spread out of over the complete investment period.
- The total amount of investment periods is varying in the case studies. This includes the starting year of the investments as well. The key reason for this approach is the problem size, which may increase the computational time significantly.
- CO_2 taxes are not included in the levelized costs but can be calculated from the CO_2 intensity of the produced hydrogen. As a rule of thumb, a tax of 150 €/kg CO_2 corresponds to an increase in the levelized costs of hydrogen by 10 c/kg H_2.

2.3 Hydrogen demand, CO_2 storage, and availability of natural gas

The hydrogen demand within Norway and the available CO_2 storage are based on the results of the ELEGANCY deliverable D5.6.1 [2]. Hydrogen demands in Germany were obtained from the German case study with a low estimate of 3730 kt/a and a high estimate of 5580 kt/a. These numbers were established based on interactions with the Germany case study.

Compared to D5.6.1 [2], certain Norwegian demands were omitted for simplifying the problem size and avoiding the road transport of hydrogen to smaller areas due the difficulty to express these in sufficient detail within the model. The demands included in the model correspond to:

- the offshore platforms (all demands, representing a high case scenario);
- the onshore industrial demand excluding the heat demand. The latter was excluded as it was not possible to obtain a geographical distribution of the demands.

The following identified demands were excluded to simplify the problem size or due to lack of geographical resolution:

- The methanol production facility in Tjeldbergodden. The reason for this is that the emissions of the facility correspond to a very low CO_2 intensity of hydrogen as the majority of the CO_2 is utilized again in the methanol. Including the hydrogen demand would also require including a CO_2 demand (7.3 kg CO_2/kg H_2 based on the stoichiometry of the reaction). If the CO_2 originates from fossil fuel, there would be no benefit in providing the CO_2 and the hydrogen externally to the methanol production facility.
- Hydrogen demand in transport due to the low demand number of the transport sector compared to the industrial and offshore needs. If it would have been included, it would not impact the location for hydrogen production as the overall demand is in the range of 60 kt/a, less than 2 % of the low estimate for the German demand.

The time evolution for the hydrogen demands is as follows:

- Offshore demand in the Norwegian sea: from 2040 onwards
- Offshore demand in the North Sea: Ekofisk, Eldfisk, Sleipnir, Ula, and Snorre from 2035 onwards, the other platforms from 2030 onwards.
- Onshore demand industry: from 2030 onwards
- German demand from 2035 onwards

Note, that these assumptions impact the hydrogen distribution network and when certain infrastructure is built.

CO_2 storage utilizes the numbers in D5.6.1 [2] with a geographical distribution based on the CO_2 atlas of the Norwegian Petroleum Directorate [3]. storage fields are on a coastal grid cell (e.g. Johansen). Here, the actual storage size was moved to the adjacent sea grid cell to include the calculation of the required pipeline length.

Norway does not possess a large onshore natural gas grid as it is for example available in Germany. Therefore, the availability of natural gas for hydrogen production was limited to certain grid cells in which natural gas is available. These grid cells include Tjeldbergodden, Nyhamna, Kollsnes, Kårstø, and Dornum. The industry park Herøya was not included as it was not possible to obtain numbers on how much natural gas is available at the industry park.

2.4 Process and cost data

2.4.1 Cost assumptions for commodities

The cost assumptions for the utilized commodities are based on the report "Langsiktig kraftmarkedsanalyse 2019-2040" from the Norwegian Water Resources and Energy Directorate (NVE) [4]. The model allows different price regions accounting for differences in prices in Germany and Norway. Similarly, it is possible to include different CO_2 taxes in Norway and in Germany.

The chosen prices are given in Table 1. Both the natural gas and the electricity prices are based on the forecast for 2040. The difference in the natural gas price between Germany and Norway is related to the transmission costs of hydrogen. CO_2 prices were not included. However, this value is also rather small for the overall hydrogen costs and are not significant enough for defining the production location. As an example, a CO_2 price of 150 €/t would increase the price of hydrogen by 10 c while an increase in the natural gas price by 2 [€/GJ LHV] leads to the same price increase.

Table 1: Used prices for commodities.

		Norway	Germany
Natural gas	[€/GJ LHV]	5.56	5.69
Electricity	[€/MWh]	43	50

2.4.2 Hydrogen production and transport

The key process parameters are based on the HYPER project[1] which investigated the production and liquefaction of hydrogen in Norway. The process parameters for the hydrogen production facilities are based on first principle models developed in Aspen HYSYS. In total, three different sizes based on autothermal reforming with aMDEA CO_2 capture and PSA hydrogen recovery are included. Furthermore, a single electrolyser with an electric input of 100 MW was added to account for small scale production of hydrogen. Table 2 provides the cost data for the different process while Table 3 describes the stoichiometry in the modelling of the different processes. All ATR sizes utilize the same stoichiometry. Note, that the ATR process is a net generator of electricity due to an inclusion of stream turbines for improved utilization of the heat generated in the process. The outlet pressure of hydrogen is around 35 bar. This pressure is as well used for the hydrogen produced by electrolysis. The capacity factor of the ATR and the electrolyser is set to 95 %, that is 5 % of the year is reserved for maintenance. When the term utilization factor is used in the following, it corresponds then to a percentage of the 95 %. Theoretically, it may be possible to also include a larger ATR reactor. The used large reactor corresponds to 1220 MW on HHV basis and 1040 MW on LHV basis. In the H21 study [5], Equinor designed an ATR-based process with 1500 MW, showing that it is possible to obtain larger processes with reduced cost through economy-of-scale. Due to the integer nature of the value-chain tool, it is however not possible to include all potential sizes as it would increase the problem size significantly. Hence, back-of-the-envelope calculations should be performed based on the results.

Table 2: Parameters for the different processes.

	Production capacity	CAPEX	Fixed OPEX	Variable OPEX
	[t/d]	[1000 €]	[1000 €/a]	[€/kg]
ATR small	100	219 603	10 510	0.0564
ATR medium	500	677 512	35 411	0.0564
ATR large	750	899 872	48 373	0.0564
Electrolyser	49	97 907	3 591	0.0766

Table 3: Stoichiometry of the two hydrogen production technologies

	Natural gas	Emitted CO_2	Captured CO_2	Compressed H_2	Power
	[kg/kg H_2]	[kg/kg H_2]	[kg/kg H_2]	[kg/kg H_2]	[kWh/kg H_2]
ATR	-3.608	0.67	8.865	1	0.348
Electrolysis	-	-	-	1	-50.132

[1] Gardarsdotti S., Voldsund M., Roussanaly S, Comparative techno-economic assessment of low-CO2 hydrogen production technologies, Hyper closing Seminar, Brussels, 2019-12-10.

Hydrogen offshore pipeline transport data is based on data obtained from Gassco and remains confidential. The compression of hydrogen is modelled inside the hydrogen landfalls, both the capital expenditures of the compressors and the electricity requirements. 15 maintenance days a year were included in the pipeline calculations. Onshore hydrogen transport is conducted using two different pipeline sizes. Onshore trailer transport was considered but eventually omitted due to difficulties in including trailer transport in the value chain tool. Note, that the tortuosity of the Norwegian landscape renders proper calculations difficult. As an example, transport over the Hardangervidda or within the Norwegian coastline in Hordaland may be cost prohibitive. Hence, it is necessary to conduct further analysis based on production locations and potential transport modes.

2.4.3 CO_2 transport and storage

CO_2 transport data are calculated from the inhouse iCCS tool [6]. CO_2 pipeline transport is considered with a capacity of 1.5, 3, 5, 10, 20, 30, 35, 45, 50, and 60 Mt and ship transport with a capacity of 10, 20, 30, 35, 45, and 50 Mt CO_2, depending on the specific case. A key problem is the length of the pipeline as longer lengths require either booster stations or a larger inlet pressure [7]. Correspondingly, the relative costs of a pipeline per length unit is depending on the length for which the costs of a pipeline are calculated. As an example, a 35 Mt CO_2 pipeline of 500 km length has an 23 % increased relative cost compared to a pipeline of 200 km length, while the increase is 30 % for a 50 Mt CO_2 pipeline. As pipeline costs are in the model not given for the overall length of a pipeline but for the length from one grid cell to a neighboring grid cell, several different costs are implemented depending on the investigated scenario.

The length utilized for calculating the relative CAPEX and OPEX is depending on the investigated case study and will be given in the respective description.

3 INVESTIGATED CASES

Several cases for hydrogen production from natural gas with carbon capture and storage were investigated. These focus on the one hand on the supply to the Norwegian hydrogen demand, focusing on large scale industrial users, and the export of hydrogen to Germany. In total, the investigations can be differentiated in:

1. Complete Norway except Nord-Norge, including the region to Dornum in Germany.
2. Only the export region from Norway to Germany, that is Kårstø to Dornum.
3. Only the export region from Norway to Germany, that is Kårstø to Dornum and additional CO_2 send to storage from Naturgassparken in Øygarden.
4. Only the Norwegian sea region.

Figure 1 illustrates the individual regions used in the analysis.

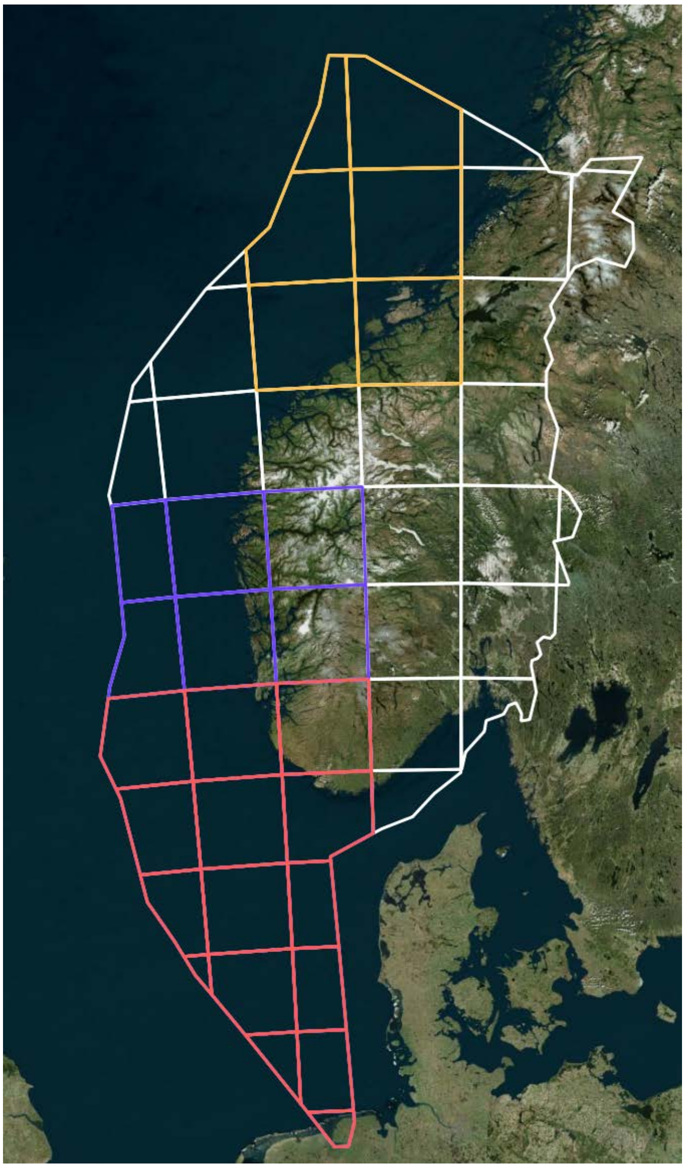

Figure 2: Area investigated including the different grid points. The complete region used in investigations 1 contains all grid cells (white, yellow, blue, and red). Investigations 2 correspond to the red grid cells, investigations 3 to the red and blue grid cells, and investigations 4 to the yellow grid cells.

3.1 Complete Norway except Nord-Norge, including the region to Dornum in Germany

This analysis focuses on satisfying the domestic demand in Norway outlined in Section 2.3 and the export demand in Germany and potential strategies that could be used. The investigated time horizon is 25 years from 2030 onwards. Section 2.3 furthermore outlines when the respective hydrogen demand is present. Two sets of simulations were conducted, once with a demand of 5580 kt/a in Germany (labelled as case a) in the following), and once with a demand of 3730 kt/a in Germany (labelled as case b) in the following).

The specified mixed integer gap was 1 % as smaller gaps result in unnecessary long run times. It is worth noting that it was not feasible to reach a solution within the specified gap after one day or even 3 days in certain simulations.

Figure 3 illustrates the results for both a German demand of 5580 kt/a (gap of 1 %) and 3730 kt/a (gap of 1.44 %).

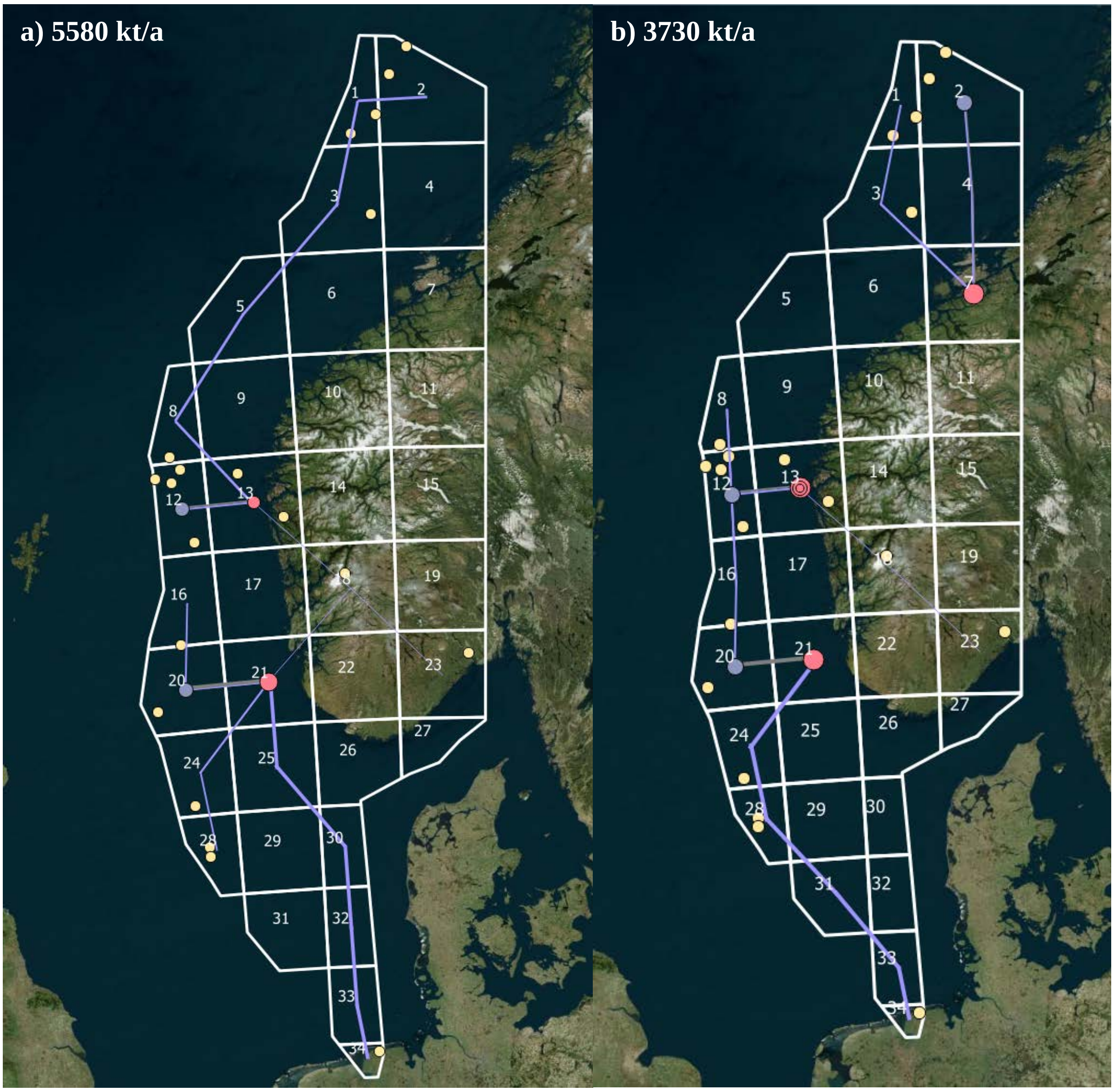

Figure 3: Layout of the hydrogen-CCS chain for a demand in Germany of a) 5580 kt/a and b) 3730 kt/a.

There are several similarities in the production structure:

1. Production for export to Germany is located in Kårstø.
2. The majority of the supply to the Norwegian continental shelf is located in Kollsnes/Mongstad.

However, there are also differences in structure.

1. The Norwegian sea region is supplied from Kollsnes/Mongstad in case a), while there is an individual production in Tjeldbergodden in case b).
2. The supply of the hydrogen to the southern North Sea platforms is conducted by a separate pipeline in case a) while it utilizes the export pipeline in case b).
3. The industrial demand in Tyssedal and Porsgrunn is satisfied by hydrogen production in Kollsnes/Mongstad and Kårstø in case a) and only from Kollsnes/Mongstad in case b).

Especially point 1 is significant as it corresponds to building a long pipeline for hydrogen supply to the Norwegian sea region. A key contributing factor for this difference can be seen in the chosen hydrogen production plant sizes. As the capital expenditures for hydrogen production plants are larger than the ones for the transport infrastructure, smaller utilizations of plants may result in larger costs.

As result of this, the two hydrogen production sites are found to be optimal in case a): 1) a set of ATR plants with a production capacity of 1500 t/d with a utilization factor of 100 % in the Kollsnes/Mongstad region and 2) set of ATR plants in the Kårstø region with a capacity of 17250 t/d[2] and a utilization factor of 99.55 %.

Meanwhile case b) results in three production sited: 1) a set of ATR plants with a capacity of 750 t/d (utilization factor of 95.38 %) in Tjeldbergodden 2) a set of ATR plants with a capacity of 1450 t/d (utilization factor of 97.32 %) in Kollsnes/Mongstad and 3) a set of ATR plants with a capacity of 9750 t/d (utilization factor of 99.59 %) in Kårstø. It may be potentially cheaper to still produce in Tjeldbergodden if the process plants in Mongstad/Kollsnes are sized differently.

Especially the number of plants in case b) in Kollsnes/Mongstad highlights the importance of the sizes of the hydrogen production plant on the total system cost. The difference in point 2 may stem from the different pipeline size for supplying hydrogen demand to Germany. Here, it may be cheaper for the smaller pipeline in case b) to build a single pipeline while in case a), the opposite holds. Point 3 is again based on the production volume of the different hydrogen plants, as a higher utilization is always preferred due to relative large contribution of the capital expenditures of hydrogen plants.

The levelized cost of hydrogen is 1.597 €/kg for case a) and 1.614 €/kg in case b). This levelized cost is averaged over the overall infrastructure. However, the levelized cost of supplying hydrogen to e.g. Germany may be smaller due to an improved economy of scale within the hydrogen production for export. This is especially interesting for the hydrogen and CO_2 pipelines which exhibit significant economy of scale.

[2] The exact sizes of the proposed plants are only indicative (e.g. how many with a capacity of 750 t/d, etc.), although we included 3 different ATR sizes in Section 2.4.2.

3.2 Export Norway to Germany

As outlined in the previous section, it is of interest to consider purely the levelized cost of hydrogen for delivery to Germany. Here, the model is simulated for a period of 25 years with a constant demand of 5580 kt/a (highest amount of the German case study) or 3730 kt/a (lowest demand of the German case study. A mixed integer gap of 0.1 % was specified to avoid long runtimes in which only the lower bound changes.

In total, six potential strategies/scenarios were investigated for the two hydrogen demands:

1. Europipe is available for the export of hydrogen to Germany without any costs associated.
2. Europipe is not available for the export of hydrogen to Germany.
3. Europipe is not available and it is not allowed to build a hydrogen pipeline from Norway to Germany.
4. Europipe is not available for hydrogen export and it is not allowed to transport either hydrogen or CO_2 to or from Germany in pipelines. Hence, it is necessary to use ship transport of either hydrogen of CO_2.
5. Sane as strategy 3, but it is allowed to directly transport CO_2 for storage to the Norwegian continental shelf without going via Norwegian Shore.
6. Same as strategy 1, but with an additional 10 Mt CO_2/y from Germany and which shall be stored.
7. Same as strategy 2, but with an additional 10 Mt CO_2/y from Germany and which shall be stored (only for 3730 kt/a hydrogen demand in Germany).

The chosen pipeline length was 200 km for the CO_2 pipelines from the Norwegian coast to the Norwegian continental shelf and 500 km for the pipelines from Germany to the Norwegian coast (or alternatively from Germany to the Norwegian continental shelf).

3.2.1 German demand of 5580 kt/a

Table 4 summarizes the main results from the analysis. The levelized costs of hydrogen are given by 3 significant digits but note that there is uncertainty related to all cost parameters used in the model, and hence, it may not necessarily be feasible to distinguish to this extent.

There is no difference in the number of hydrogen production facilities, as the demand is fixed and the same in all investigated cases. Hence, the best number of ATR plants is chosen independently where the production is located. Electrolysis is not cost competitive for large-scale hydrogen production in Norway with the chosen capital expenditure and natural gas and electricity price. However, we can see a clear distinguishable ranking and can deduce the following:

1. If Europipe can be used for hydrogen export, the production will be located in Norway. It is necessary to build a second hydrogen pipeline for the transport of hydrogen from Norway to Germany as the demand exceeds the capacity of Europipe significantly.
2. If Europipe is not available, hydrogen is still produced in Norway. There is not a large change in the cost due to the limited capacity of Europipe and the fixed size of the hydrogen pipelines.
3. If it is not allowed to transport hydrogen from Norway to Germany in pipelines, it is preferred to produce in Germany and transport the CO_2 to Agder and build a pipeline from there to the Bryne/Sandnes formation for storage.
4. CO_2 ship transport is preferred over hydrogen ship transport, potentially due to the short distance, the reduced cooling energy requirement, and the simpler design. CO_2 injection in Bryne/Sandnes formation if ship transport is used.
5. CO_2 is directly injected in the Bryne/Sandnes formation from Germany, if allowed, reducing the costs compared to case 3.
6. If Europipe is available and additional CO_2 has to be stored from Germany, production remains in Norway. The Germany CO_2 is transported to Agder and from there to the Bryne/Sandnes formation

for storage with appropriate pipeline sizes. Hence, the potential synergy is smaller than the benefit of producing in Norway, using Europipe and have additional economy of scale for CO_2 transport.

Table 4: Summary of the results for the export to Germany for a hydrogen demand of 5580 kt/a.

Case	Levelized cost of hydrogen	Production in	Hydrogen transport	CO_2 transport
	[€/kg]	[-]	[-]	[-]
1	1.543	Norway	Europipe + 52-inch H_2 pipe	Pipeline with 50 Mt/a capacity
2	1.544	Norway	54-inch H_2 pipe	Pipeline with 50 Mt/a capacity
3	1.571	Germany	-	Pipeline with 50 Mt/a capacity to Agder, pipeline with 50 Mt/a capacity to the shelf for CO_2 from Germany
4	1.598	Germany	-	50 Mt/a capacity ships to Agder, pipeline with 50 Mt/a capacity to the shelf for CO_2 from Germany
5	1.561	Germany	-	Pipeline with 50 Mt/a capacity to the shelf from GER
6	1.543	Norway	Europipe + 52-inch H_2 pipe	Pipeline with 50 Mt/a capacity in Norway, Pipeline with 10 Mt/a capacity to Agder, pipeline with 10 Mt/a capacity to the shelf for CO_2 from Germany.

Figure 2 illustrates the pipeline layout of Case 2 and Case 3 as examples of potential pipeline layouts. Case 1 is similar to Case 2 while Case 4 looks similar to Case 3 with the pipelines from Germany to Norway being substituted by CO_2 ship transport.

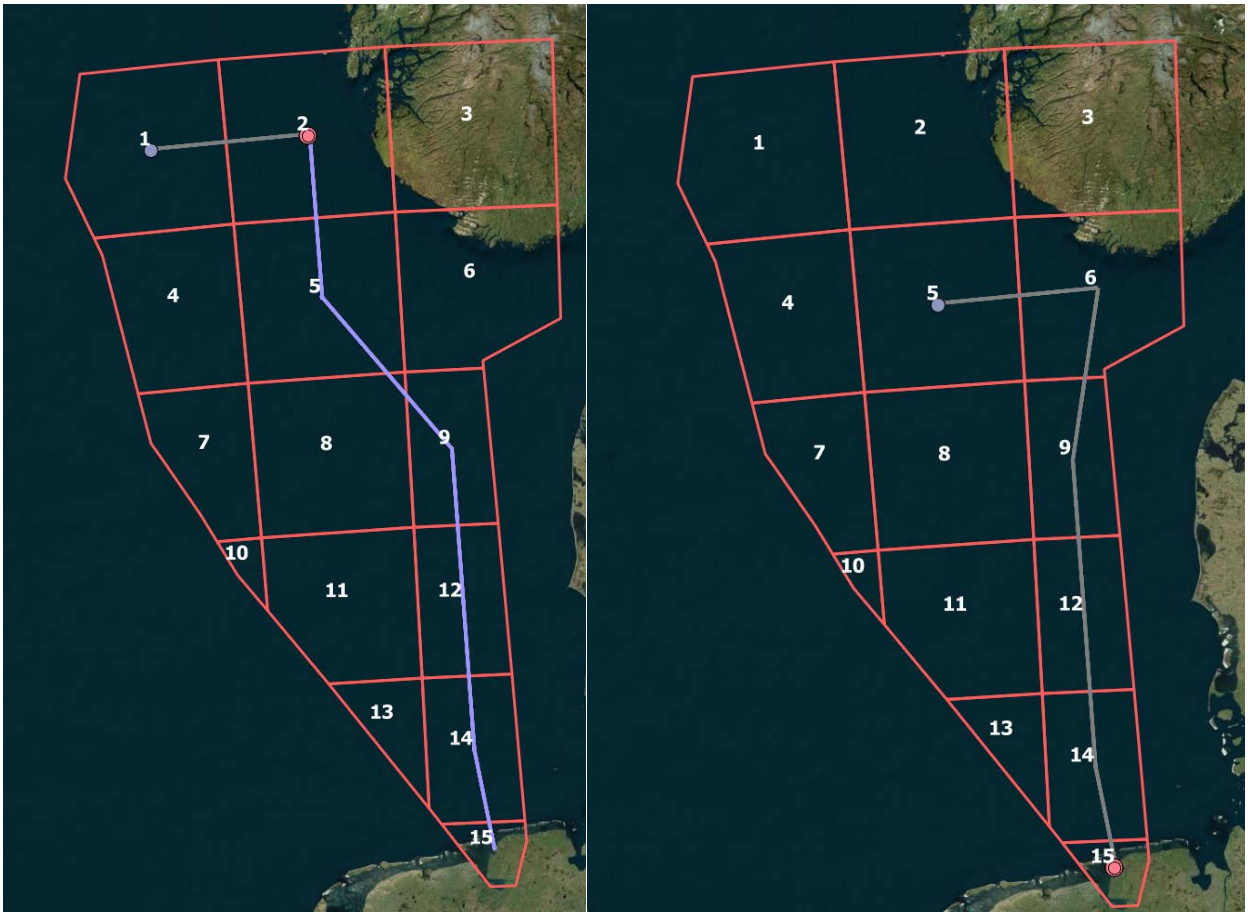

Figure 4: Illustration of the topology for hydrogen transport for Case 2 (left), and case 3 (right). Grey circles correspond to injection wells, grey lines to CO_2 pipelines, blue lines to hydrogen pipelines, and red circles to hydrogen production. Note, that the model uses center points of grid cells. This leads to certain production and storage units being located in the sea, despite being in fact located on the shore.

The key contributor to the levelized cost of hydrogen is the natural gas price. It corresponds to more than 60 % of the levelized cost of hydrogen. It is followed by the capital costs and fixed operation costs for the hydrogen production facilities at 30 %. The hydrogen transport as well as CO_2 storage and transport are included in the remaining costs.

As the production facilities are the same in all cases and the total production of hydrogen is fixed, one can obtain a better comparison by looking at the individual contribution of the different transport modes to the total cost of hydrogen. Hence, the levelized cost of hydrogen is split into CAPEX and fixed and variable OPEX for transport of hydrogen and CO_2. This also includes the land connections like harbours or landfalls for pipelines. Natural gas costs are included showing the premium of transporting natural gas to Germany. Power export/import from the hydrogen production sites and the hydrogen landfalls is included to account for the different electricity prices in Germany and Norway. The production CAPEX and fixed and variable OPEX are as well excluded due to the same number of production facilities in all cases. Similarly, CO_2 storage costs do not differentiate where the CO_2 is from. Hence, the value is independent on the layout of the H_2-CCS chain and should be excluded in the analysis.

Table 5 summarizes the cost contributions of CO_2 and hydrogen transport for the different investigated cases, including the electricity import/export and natural gas import. By neglecting the production and storage costs, we can see that there are significant differences between the 6 investigated scenarios. Note, that in case 6 we only included the CO_2 transport and storage costs associated to hydrogen production. These differences arise equally though increased capital costs and operational costs. The premium for natural gas in Germany is counteracted by the increased electricity demand for compressing the hydrogen for transport to Germany. Furthermore, the length of the pipeline from Kårstø to Germany compared to the length of the CO_2 pipeline from Germany to the southern North Sea has an impact on the overall costs. Another interesting factor from this analysis is that the distribution between levelized capital and operational costs is different in the case of CO_2 ship transport as the operational costs are significantly higher due to the fuel usage and sailors required for the ship transport.

Table 5: Differentiations in the factors contributing to the overall levelized cost of hydrogen in ct/kg for a hydrogen demand of 5580 kt/a.

Component [ct./kg]	1	2	3	4	5	6
CAPEX - Transport of hydrogen and CO_2	2.55	2.63	4.03	2.71	3.27	2.55
OPEX - Transport of hydrogen and CO_2	0.19	0.19	0.87	4.90	0.67	0.19
OPEX – Electricity import	0.27	0.27	-1.74	-1.74	-1.74	0.27
OPEX – Natural gas premium	0.00	0.00	2.53	2.53	2.53	0.00
Sum [ct./kg]	3.01	3.09	5.69	8.40	4.73	3.01
Levelized cost of hydrogen without NG [€/kg]	0.621	0.623	0.626	0.642	0.605	0.621
Levelized investment costs [€/kg]	0.337	0.338	0.352	0.338	0.344	0.337

3.2.2 German demand of 3730 kt/a

Table 6 summarizes the cases for a hydrogen demand of 3730 kt/a. The total hydrogen demand would make it most cost effective to use a single 100 MW electrolyser as the production capacities of ATRs are not able to produce the required amount. However, in practice, one would produce slightly bigger reactors. Hence, the production capacity of the medium ATR was increased to 520 t/d.

We can see that the reduction in demand affects the costs only marginally. Transport costs are increased while production costs remain more or less the same as the processes have an equal utilization. The former can be explained by the reduction in costs through pipelines with higher capacity while the latter can be explained by the utilization of the same type of reactors.

If there is additional CO_2 available in Germany, the production is still located in Norway. Consequently, there are no cost synergies even if it is possible to utilize a single pipeline for the transport of industrial CO_2 and CO_2 from hydrogen production from Germany to Norway. This implies that the premium for natural gas and CAPEX and OPEX for CO_2 pipelines still outweighs benefits using only a single CO_2 pipeline from Germany.

Table 6: Summary of the results for the export to Germany for a hydrogen demand of 3730 kt/a.

Component [ct./kg]	1	2	3	4	5	7
CAPEX - Transport of hydrogen and CO_2	3.21	3.44	4.94	3.14	3.94	3.44
OPEX - Transport of hydrogen and CO_2	0.22	0.22	1.03	5.25	0.70	0.22
OPEX – Electricity import	0.27	0.27	-1.74	-1.74	-1.74	0.27
OPEX – Natural gas premium	0.00	0.00	2.53	2.53	2.53	0.00
Sum [ct./kg]	3.70	3.93	6.76	9.18	5.43	3.93
Levelized cost of hydrogen [€/kg]	1.552	1.554	1.582	1.607	1.570	1.554
Levelized cost of hydrogen without NG [€/kg]	0.621	0.623	0.626	0.651	0.614	0.623
Levelized investment costs [€/kg]	0.344	0.347	0.362	0.344	0.352	0.347

3.3 Export from Norway to Germany and synergies with the development of a Norwegian CCS infrastructure

In order analyse the impact of hydrogen production with CCS on potential storage costs, several case studies were conducted based on the limited region for export to Germany with inclusion of the Hordaland and the southern part of Sogne og Fjordane.(red and blue cells in Figure 1). The additional CO_2 was located at Naturgassparken in Øygarden. Simulations with additional 5 Mt, 10 Mt, 15 Mt CO_2 for storage were conducted for a German hydrogen demand of both 3730 kt/a and 5580 kt/a.

In neither case, we could observe any synergies between hydrogen production with CCS and the storage of the additional CO_2. The reason for this finding is that the location of hydrogen production facilities is based on the large export German demand. Additional CO_2 in certain grid cells does not influence where to produce hydrogen as the reduction in hydrogen pipeline length is more beneficial than the economy of scale for transporting the CO_2 to storage. However, it may be beneficial for reduced costs in CO_2 transport and storage if the additional CO_2 would be transported to the sites of hydrogen production and send to storage from these sides. Then, there would be cost reductions for the transportation and storage for both the CO_2 from hydrogen production and additional CO_2. Based on the analysis in Section 3.1, the production sites at Kollsnes/Mongstad and Nyhamna could be utilized for local CO_2 hubs for storage of additional CO_2.

3.4 Norwegian Sea region

The Norwegian Sea region was investigated specifically to account for the levelized costs of production for offshore usage in the oil and gas industry with a small demand. It requires the construction of only a single large ATR due to the smaller volume. Hence, the capital and fixed operational costs of the infrastructure contribute more to the overall costs. The overall contribution of the transport network is 21.0 ct/kg hydrogen for the capital costs and 1.3 ct/kg hydrogen for the operational costs for a levelized cost of hydrogen of 1.789 €/kg, significantly higher than the export costs to Europe. Furthermore, the ATR is not fully utilized in this case increasing the contribution of the capital costs and the fixed operational costs compared to the cases in which export to Europe was investigated.

As the model is utilizing standard sizes for both reactor and transport infrastructure, it would be beneficial to perform a detailed analysis for satisfying the demand in the offshore industry.

4 CONCLUSIONS

The production of hydrogen and storage of CO_2 is governed mostly by the export possibilities due to the large demand of hydrogen outside Norway compared to the domestic demand. This implies that irrespectively how much hydrogen is used within Norway, the production facilities will be located where it is most promising for the export of hydrogen. This is not surprising as the final energy demand in Norway including energy carriers as reactant is 244 TWh of which 116 TWh is electricity. The non-electricity demand in Norway is hence in the same range as the total export of energy to Germany or even lower. This situation is similar to existing natural gas export from Norway, which corresponds to around 1000 TWh.

Reusing the existing gas infrastructure may result in small savings for the hydrogen export as outlined in Section 3.2. However, the demand in Germany significantly exceeds the capacity of Europipe and it is necessary to build new pipelines for satisfying the demand. One advantage of reusing existing pipelines would be however that it could kickstart the development of a hydrogen industry in Norway which can be latter on extended with additional export capacity.

The difference in price between production in Norway and Germany is mostly affected by the transport costs of both hydrogen and CO_2. These differences are significant when looking purely at the transport costs in the analysis but are only a small portion of the overall levelized cost of hydrogen.

The analyses with additional CO_2 for storage from Germany change this picture. Large reductions in costs can then only be achieved, if the hydrogen is produced in Germany as only in this approach larger CO_2 pipelines could be utilized exploiting the economy of scale effect. However, in the case of the large demand in Germany (5580 kt/a), it is not possible to transport a significant additional amount of CO_2 in the CO_2 pipelines used for captured CO_2 from hydrogen production or switch to a larger pipeline size as the German demand already corresponds to around 50 Mt CO_2/a. The maximum length of a pipeline with a capacity of 55 Mt CO_2/a is too short for transporting the CO_2 from Germany to Norway, requiring the construction of a second pipeline. If the hydrogen is produced in Norway, only the injection pipeline results in cost reduction for additional CO_2 to be sent to storage. This implies that there are no synergies for the transport of CO_2 to Norway and the CO_2 stored from hydrogen production except for the injection pipeline. Even in the case of a small demand in Germany (3730 kt/a), the production is located in Norway although it would be possible to transport the industrial CO_2 and the CO_2 from hydrogen production from Germany in a single pipeline. Note however, that the additional CO_2 would reduce the costs of hydrogen production in Germany, even if it is then still more expensive to produce in Germany.

Specifying an additional demand in Norway is more challenging as the hydrogen production site is not known beforehand. Hence, it may be specified in cells which do not have hydrogen production. This would then result in investing into CO_2 transport and storage infrastructure without synergies with the CO_2 originating in the hydrogen production facilities. Instead, the location of CO_2 hubs should be based on the location of hydrogen production facilities and cost benefits could be calculated as part of the post processing of the results. Based on the results presented in Section 3.1, these CO_2 should be located near Kårstø, Mongstad/Kollsnes, and potentially Tjeldbergodden.

The local price of hydrogen in Norway is in general higher due to the geography and the low population density. Here, the cost of transport of hydrogen (and CO_2) and the utilization of the hydrogen production facility play a more pronounced role compared to the high volumes for the export. This is exemplified by the case study investigating the Norwegian sea region where the levelized cost of hydrogen is 15-20 ct/kg higher. All production is focused in Vestlandet (except for satisfying the demand in the Norwegian sea) due to the low identified demand in Østlandet and Nord-Norge. Nord-Norge was therefore decoupled from the model to simplify calculations. Furthermore, the approach of calculating the levelized costs as average costs of the overall investigated system would be strongly distorted by the increased prices of export of hydrogen from Nord-Norge, as the latter would require liquefaction of hydrogen for transport. To this end, it is more beneficial to conduct analysis focussing only on Nord-Norge. These analyses are preferably more detailed as there is no advantage in using the value chain tool for regions in which only a single production site is considered.

All results presented are based on simplified process and pipeline models. Hence, it may be necessary to conducted detailed analysis of the individual value chain sections for assessing the associated costs properly. Especially pipeline costs are difficult to incorporate due to pressure drop in pipelines and as the costs of pipelines are depending on the total length of the pipeline. The latter is especially difficult to incorporate due to the grid cell approach.

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