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Indirect electrification of transport – a study of hydrogen supply systems for heavy road transportation

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Summary

This work analyses and compares electrolysis-based hydrogen supply systems for heavy road transportation. A cost-minimizing optimization model that makes production meet demand at a hydrogen refueling station at the lowest total cost is used. The results show that when using electrolysis to produce hydrogen, a standalone solution with a decentralized wind power supply (in island mode) yields higher hydrogen production costs compared to when the electrolyzer is powered from the electricity grid. Centralized hydrogen production with hydrogen distributed out to refueling stations gives slightly lower costs for production and storage than the grid-connected decentralized case, but adding the cost for hydrogen transport makes the total cost slightly higher.

Keywords: hydrogen, infrastructure, freight transport, energy storage, fuel cell vehicle

1 Introduction

To reach the European climate targets, lowering emissions from transportation is a key challenge as transportation accounts for 37 % of global greenhouse gas (GHG*)* emissions and about a quarter of the European GHG emissions (excluding international maritime emissions) [1-3]. Hydrogen has been identified as a possible energy carrier in the transition to a sustainable transport sector, especially when it comes to heavy freight transport [4-6]. Although hydrogen is hardly used for transportation at present, it is used in industry. Hydrogen can be produced from a variety of sources, with steam reforming of natural gas currently standing for the largest share of production followed by oil reforming and coal gasification. These processes are associated with significant GHG emissions. However, there are other methods for producing hydrogen that have low GHG emissions, such as water electrolysis and steam methane reforming (SMR) of natural gas or biogas with carbon capture and storage (CCS) [7-9].

Hydrogen supply for refueling stations has been evaluated in several studies [10-14]. When it comes to hydrogen produced through electrolysis, the production cost depends heavily on the cost of electricity. The projections for the Levelized cost of hydrogen (LCOH) available in the literature are based on historical electricity price data. An electricity system with high shares of variable renewable electricity (VRE) production will generate higher electricity price fluctuations, thereby changing the conditions for hydrogen production. Tang et al. [11] compare hydrogen production at refueling stations run in an island mode (I.e., not connected to the electric grid) using dedicated wind and solar power, with a similar but grid-connected system, concluding that grid connection tends to achieve a lower LCOH. However, Tang et al. [11] assume a constant hydrogen demand and only study historical spot market prices for electricity, meaning that it will not represent the electricity prices in a future electricity system. An economic analysis of a standalone wind-powered system for supplying hydrogen to refueling stations in Sweden was also studied by Siyal et al. [10]. They concluded that such a setup can help in reaching the goal of a fossil-free transport sector in Sweden, however, the setup investigated was not compared with other systems for hydrogen production. Hydrogen production can either be located at the site of the refueling station, i.e., in a decentralized system or be centrally located with a distribution system that transports hydrogen from the production site to the refueling station [13]. Although the above-mentioned works give insights into the cost of hydrogen for transport, there is a lack of studies that evaluate multiple hydrogen supply scenarios. For those who have more than one supply scenario, studies are limited to a narrow temporal scope.

This paper examines the cost of three hydrogen production systems that supply hydrogen to refueling stations for heavy transport. The purpose is to study the difference between centralized and decentralized hydrogen production systems, as well as the difference between standalone and grid-connected systems for hydrogen supply for refueling stations. Both current and possible future electricity systems are considered, to evaluate how the cost efficiency of the different hydrogen supply systems changes as the electricity system evolves.

2 Method

The study develops and applies a techno-economic optimization model to compare the system efficiency and cost of hydrogen for the three hydrogen supply systems. The model includes an electricity source, energy conversion to hydrogen, as well as distribution and storage of hydrogen. For the three hydrogen supply systems investigated, the energy demand, and related costs for the different parts of the supply system are used to estimate the system efficiency and total system costs. Optimization is carried out to satisfy an exogenous hydrogen demand profile at the lowest total cost. Although the methodology applies to any region, Sweden and electricity price area SE3 is chosen as a case.

2.1 Hydrogen supply systems

As indicated above, hydrogen used at refueling stations can either be produced where it is consumed or produced centrally and distributed from the production site to the refueling station. The hydrogen supply systems investigated in this work cover hydrogen produced from water electrolysis where the electricity supply is either from the electric grid or dedicated wind power plants.

The three different hydrogen supply systems investigated are:

(1) Hydrogen production at the refueling station, with a standalone system with dedicated wind power plants located in the vicinity of the refueling station providing electricity for the electrolyzer. Hydrogen storage tanks are used to store hydrogen between production and demand at the filling station.

(2) As (1) but with the electricity supplied from the local electric grid to power the electrolyzer. For this, several electricity price curves are used to show price variations for both the current and possible future electricity systems.

(3) A large-scale, centralized production using electrolysis from which the hydrogen is distributed to several refueling stations using trucks. Large-scale lined rock cavern centralized storage is used to accompany days up to seasonal variations while a storage system similar to cases (1) and (2) is used to store hydrogen at a higher pressure at the refueling station to meet immediate demand.

Table 1 shows a summary of the studied systems. All cases use tube storage as the storage option at refueling stations. Hydrogen is stored at 200 bars and the compression to this pressure is included in the model. Higher pressure would be needed for refueling of vehicles, however, the compression that would be needed is the same for all systems and therefore not included in this comparison of systems. For the centralized hydrogen supply system (3), the model can invest in lined rock cavern (LRC) storage at the production site. The model is run for both current and future investments and electricity costs for all hydrogen supply systems.

Table 1: Summary of hydrogen supply systems investigated.

System no	Energy source	Geographical scope	Large-scale hydrogen storage	Average hydrogen transport distance	Hydrogen storage at the refueling station
(1)	Wind power	Decentralized	No	0 km	Tube storage
(2)	Grid connection	Decentralized	No	0 km	Tube storage
(3)	Grid connection	Centralized	LRC	150 km	Tube storage

2.2 Model

The different parts of the hydrogen supply system are dimensioned for each system using a cost-minimizing optimization model that makes production meet the hydrogen demand at the filling station at the lowest total cost, including costs for hydrogen storage. The model has an hourly resolution and is run for a full year. Accordingly, the hydrogen demand profile over a year has an hourly resolution and is obtained from real hourly driving data for heavy transport [15, 16].

Equation 1 describes the objective function of the model, while Equation 2 is an energy balance for hydrogen storage technologies. For the tube storage at the refueling station, the hourly discharge of the hydrogen storage is equal to the hourly hydrogen demand. In the hydrogen supply system (3) the hydrogen supplied to the tube storage equals the hydrogen discharged from the LRC storage at the centralized production site. Equation 3 describes the relation between hydrogen supplied to the storage at the production site and electricity used for hydrogen production. For the hydrogen supply system (3), the produced hydrogen through the electrolysis equals the hydrogen supplied to the hydrogen storage at the production site. Equations 4 and 5 describe limitations in how much hydrogen can be stored and the possible rate of charge for the different hydrogen storage technologies. Equation 6 describes losses from the usage of the different technologies. Equation 7 defines which variables are positive. Total system costs are divided by the total hydrogen demand in each hydrogen supply system to obtain the Levelized cost of hydrogen. Descriptions for notations used in the equations are found in

Table *2*.

$$\min\,[C^{tot} = C_p * i_p + C^{el,fix} + \sum P_t^{el} * C_t^{el,var}\,] \tag{1}$$

$$l_{pst,t++1} = l_{pst,t} + s_{pst,t}^{add} + s_{pst,t}^{rem} \tag{2}$$

$$\sum s_{pst,t}^{add} = g_{ely,t} * \eta_{ely} \tag{3}$$

$$l_{pst,t} \leq i_{pst} \tag{4}$$

$$s_{pst,t}^{add} \leq W_{pst} * i_{pst} \tag{5}$$

$$g_{p,t} = k_{p,t}^{el} * \eta_p \tag{6}$$

$$0 \leq g_{p,t}; i_p; k_{p,t}^{el}; l_{pst,t}; s_{pst,t}^{add}; s_{pst,t}^{rem} \tag{7}$$

Table 2: The sets (italic lower-case letters), parameters (upper-case letters), and variables (lower-case letters) for equations 1-6.

Notation	Description
t	Set of modeled timesteps
p	Set of modeled technologies
pst	A subset of p, hydrogen storage technologies

η_p	The combined efficiency of technology p
C_p	Annualized cost for technology p
$C^{el,fix}$	Annual fixed electricity cost
$C_t^{el,var}$	Varying cost of electricity in timestep t
C^{tot}	Total annual system cost
$g_{p,t}$	Generation from technology p in timestep t
i_p	Investment in technology p
$k_{p,t}^{el}$	Electricity use for technology p in timestep t
$l_{pst,t}$	Hydrogen level in storage pst in timestep t
$s_{pst,t}^{add}$	Hydrogen added to hydrogen storage pst in timestep t
$s_{pst,t}^{rem}$	Hydrogen removed from hydrogen storage pst in timestep t
W_{pst}	The maximum injection rate of storage pst

2.3 Costs and assumptions

Costs and technological assumptions are chosen to reflect both the current and future performance of hydrogen supply systems. Taxes and governmental fees are excluded from cost estimations, however, so are subsidies and other forms of financial support. Table 3 lists the input data to the model. Costs related to the construction and operation of the refueling station, which are not specified in the table, are not included in this study since those costs will be the same for all systems investigated. The wind power production profile is taken from Mattsson et al. [17] and represents average production for conventional wind power plants located in the Swedish electricity price area SE3 at a location with an average wind speed between 7 and 8 m/s.

Table 3 Input data for technical and economic assumptions. The numbers in bold differ between the time frames [18-22]

Part of system	Characteristic	Current estimation	Future estimation	Unit
Grid-connected electricity	Fixed power cost	31.5	31.5	k€/MW and year
	Fixed annual cost	1 819	1 819	€/year
Wind power	Investment cost	**1 120**	**960**	k€/MW
	Annual fixed O & M cost	**14.00**	**11.34**	k€/MW
	Annual variable O & M cost	**1.5**	**1.22**	€/MWh
Electrolyser	Efficiency	**65**	**74**	%
	Investment cost	**900**	**500**	k€/MW
	Annual O & M cost	4	4	% of investment cost
Transportation	Starting cost	0.42	0.42	€/kg H2
	Truck transport	0.0076	0.0076	€/kg H2 and km
Tube storage	Input capacity	10	10	% of max capacity/h
	Investment cost (incl compressor)	**57**	**22**	k€/MWh
	Annual O & M cost (incl compressor)	**6**	**4**	M€/MWh
	Round trip efficiency of storage (incl electricity to compressor)	**88**	**90**	%
Large scale storage (lined rock cavern)	Investment cost	11	11	k€/MWh

In this study, it is assumed that the share of vehicles powered by hydrogen is at a level low enough for the demand for hydrogen for transport not to affect the electricity price curve. As mentioned above, the electricity price area SE3 in Sweden is chosen as a case for this study, and the current and future electricity price curves used in the modeling are shown in Figure 1. Electricity spot prices from Nord Pool for the year 2019 are used for current cases [23] and an electricity price curve for future cases is extracted from a modeling study by Taljegård et al. [24]. The future electricity prices are for a system that has zero direct GHG emissions, i.e., a system which can be seen to envision the year 2050 system.

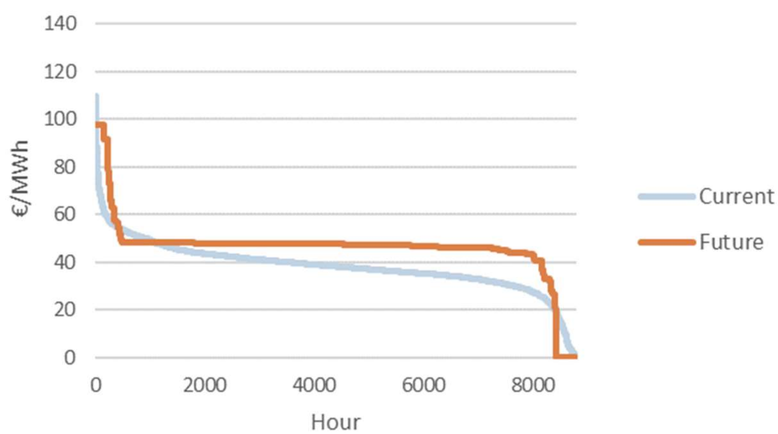

Figure 1: Sorted electricity prices for electricity price area SE3. Data for the year 2019 collected from Nord Pool is used for the current estimation [23]. Data for 2050 from Taljegard et al. [24] is used as the future estimation.

3 Results

Figure 2 shows the Levelized cost of hydrogen (LCOH) for the investigated hydrogen supply systems assuming current and future costs. The results show that the lowest costs for delivering hydrogen in SE3 (south of Sweden) are achieved in the decentralized hydrogen production system with a grid connection (2). With the centralized hydrogen supply system (3), somewhat lower costs are achieved for the production and storage of hydrogen, but the additional cost required for hydrogen transport makes the total cost higher than for the similar but decentralized system (2). Hydrogen supply system (1), which is disconnected from the electric grid, is associated with the highest LCOH, mainly due to the higher cost of storage and electricity production. Electricity costs in Figure 2 include electricity used for both hydrogen production and compression. Generally, lower costs are achieved in future cases. This is due to a combination of decreased specific costs and increases in energy efficiency.

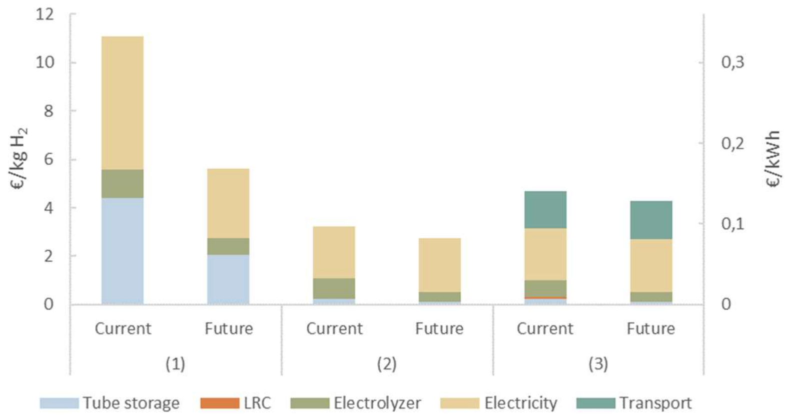

Figure 2: Levelized cost of hydrogen for the three hydrogen supply systems and two time frames.

Figure 3 shows the full load hours for electrolyzers of each hydrogen supply system, both for current and future costs. For future costs, the specific investment cost for electrolyzers is lower, and their energy efficiency is higher. The future costs for hydrogen supply systems (1) and (3) show slight decreases in the full load hours for electrolyzers, indicating that the decrease in investment costs for electrolyzers makes it cost-efficient to increase the hourly hydrogen production capacity through investing in more electrolyzers with a lower utilization rate as a consequence. For hydrogen supply system (1), which is not connected to the electricity grid, electricity availability is dependent on wind speed variations. This results in hydrogen production that varies more between hours. A larger investment in electrolyzer capacity is needed to enable an overproduction during hours when wind power is available to cover the hydrogen demand for periods of lower wind speeds. This results in significantly lower full load hours for this system assuming both current and future costs. For hydrogen supply systems (2) and (3) electricity can always be purchased, but with the availability of storage, the most expensive hours can be avoided. Additionally, the production can be lowered independently of electricity cost when the demand is low and the level in the storage is sufficient.

The hydrogen level in tube storages of supply systems (1) and (2) are shown in Figure 4. For supply system (2), utilization of the storage is high, while the utilization in the storage of system (1) is lower. The weeks during the summer with lower wind power production dimensions the size of storage for hydrogen supply system (1) as the demand does not decrease to the same extent as wind power availability during the summer season, meaning that hydrogen must be produced and stored at an earlier occasion to cover the demand. For the grid-connected hydrogen supply systems studied, hydrogen is generally produced at the same rate as consumed, which can be derived from Figure 4. Storage investments are small and are sized to allow for the rate of compression, rather than storage between hours. Different electricity price curves (I.e., the years 2015 to 2020) for grid-connected hydrogen supply systems do impact the LCOH but do not affect the system setup, i.e., the electricity price variations are not large enough to motivate further investments in storage capacity.

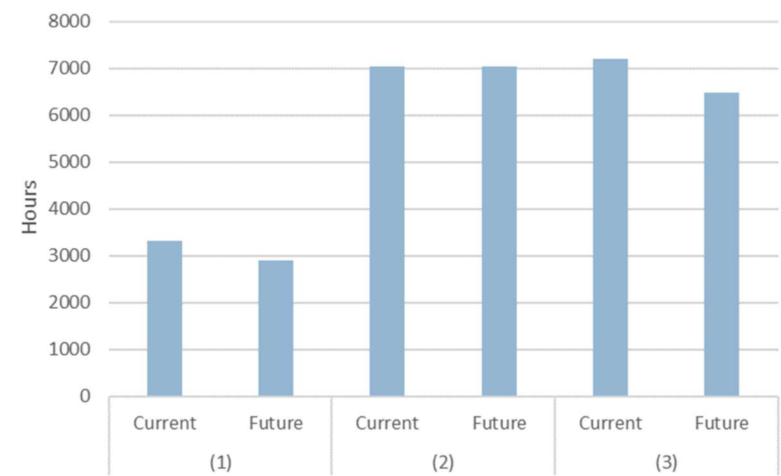

Figure 3: Full load hours for the electrolyzer for each hydrogen supply system

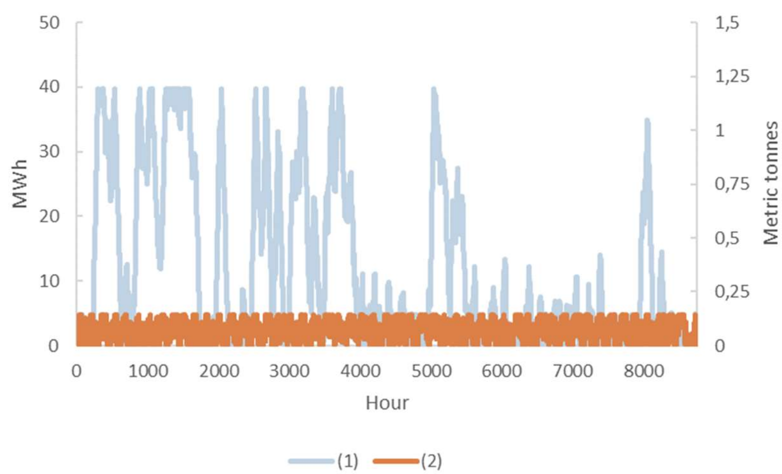

Figure 4: Hydrogen level in storage for hydrogen supply systems (1) and (2)

Sensitivity analysis

The average distance from the production site to the refueling stations in hydrogen supply system (3) was varied between 50 and 500 km. The results of this are shown in Figure 5, and as can be seen, the cost of transport increases linearly with transport distance. For all distances, the costs of centralized production remain higher than the costs for decentralized hydrogen production.

Results for hydrogen supply system (2) using different electricity price profiles are shown in Figure 6. Electricity price profiles for the additional years in the period 2015-2020 from Nord Pool for electricity price area SE3 in Sweden were used. The results show that the model invests in the same capacities for storage and electrolyzers for all systems, except for the future estimation shown as 2050 where assumed technical efficiencies and cost data differ from the systems using current technology.

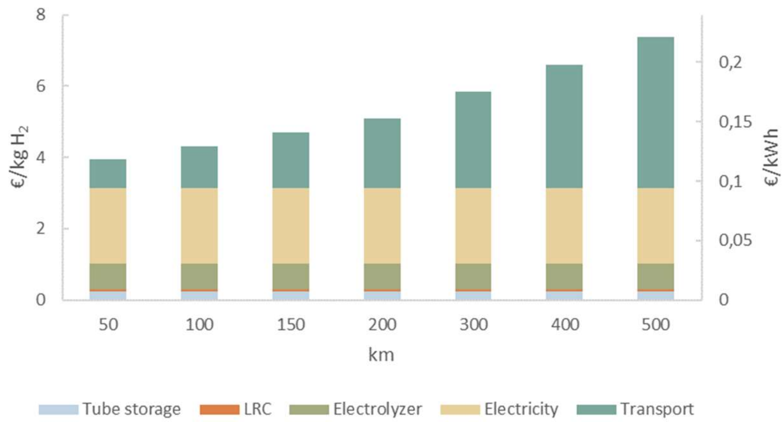

Figure 5: Cost for hydrogen from supply system (3) with different average transport distances from the production site to the refueling station.

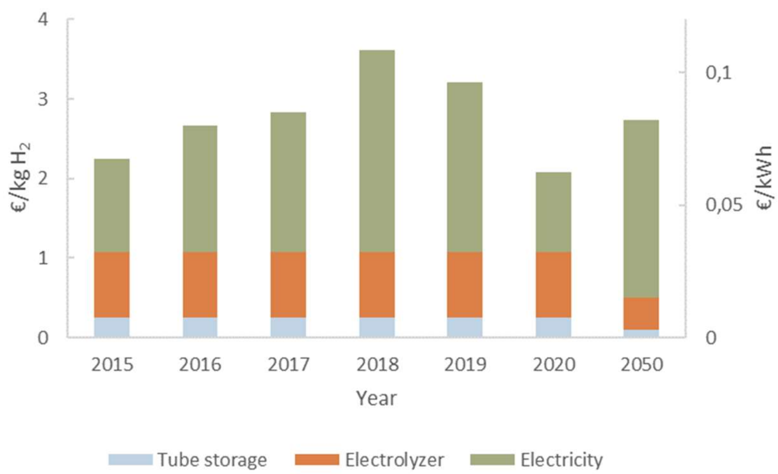

Figure 6: Results for hydrogen supply system (2) using electricity price curves from Nord Pool for 2015-2020 [23], as well as an estimation for 2050 from Taljegard et al. [24].

4 Discussion and conclusion

The results show that the three hydrogen supply systems investigated are associated with different costs. Given the assumptions in this paper, a decentralized grid-connected system (2) gives the lowest LCOH.

For hydrogen supply system (1), which is not grid-connected, investments in hydrogen storage are much larger than for supply systems (2) and (3), as investments in storage tubes must compensate for variations in wind power production. During periods of the year with low wind power production the storage demand increases, i.e. the utilization of the storage for this case is much lower than for the other supply systems. As the wind power production and hydrogen demand do not follow each other, there will be hours of the year where the marginal cost of hydrogen will near zero, and other hours that are dimensioning for the system, giving a high marginal cost of hydrogen during those hours.

The results presented each represent an optimized solution with perfect foresight: It is, therefore, likely that real-world refueling stations would need larger storage systems than those presented in this study. The storage sizes suggested by the optimization model are the lowest storage size needed with no regard to the security of supply in a system with perfect foresight and no redundancy. This would increase the costs of the hydrogen supply systems, and the cost increase may vary between the different hydrogen supply systems.

The wind data used to model hydrogen supply system (1) is representative of average wind power production in the whole electricity price area SE3. This gives a slightly smoother wind power output than when using wind data for a specific location. However, this makes the approximation more generalized. Losses and outages for planned and unplanned maintenance are included in the profile estimations. However, a single unit like in system (1), is obviously more sensitive to stops. This is not captured in the model, and a larger storage unit might be needed to manage unplanned production stops. An improvement of the model related to the wind power plants could be to allow for investments in wind power plant types optimized for low wind speeds as well as including an assumed development of wind power plants for the future case.

One could argue that allowing for the distribution of hydrogen through pipelines could lower the transport cost, thereby making centralized solutions more cost-efficient. However, the difference in production and storage costs between hydrogen supply systems (2) and (3) are small, and it seems unlikely that centralized systems will be ramped up in parallel with the possible development of increased hydrogen demand for heavy transport. Since the present work does not include any other sectors, it is not possible to say anything about the effects of other sectors driving the development of hydrogen infrastructure. In a case where hydrogen is developed in other sectors such as in industry, it might still be economically beneficial for the transport sector to be connected to centralized supply systems.

The full load hours for electrolyzers are high despite the option of large-scale storage in hydrogen supply system (3). Further, the amount of underground LRC storage invested in by the model is much lower than the sizing of LRCs planned to be developed for industry, making it an unlikely option. The construction of a LRC system would therefore likely be associated with larger costs than those in the model. The combination of high full load hours and low storage investments shows that hydrogen is produced at an even rate over the year. However, if production and storage are coupled with other sectors, the transport sector might also utilize such storage if incentivized by other sectors. It is also possible that the marginal cost of increasing storage capacity for storage constructed by another sector is low enough to motivate a centralized system (system 3) to meet the needs of the transport sector.

The model optimization in this work is carried out to minimize the total system cost which does not necessarily provide optimal system configurations, as there may be other designing factors than costs. For example, an advantage of the hydrogen supply system (1) that is not valued in the model, is self-sufficiency and independence from technical changes in the other parts of the electricity system. Another advantage of such a system could be the possibility to establish refueling stations in areas where grid capacity cannot accommodate a grid-connected solution. A centralized system such as hydrogen supply system (3) could also be an option in areas with limitations in grid capacity. This since for a production site in a centralized system, especially one with distribution through hydrogen pipelines, there is more freedom with regards to the placement of the hydrogen production site. This means that refueling stations could be placed in areas with low grid availability and still have access to clean hydrogen, as long as it is connected to the distribution system.

There are uncertainties in the cost of hydrogen supply and this study should therefore be regarded as an evaluation of the differences between different types of hydrogen supply systems, rather than an estimation of hydrogen supply costs in absolute terms. In addition, the estimations for the future case should not be seen as predictions but as a comparison of the systems when the volatility in electricity price is higher than at present.

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