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Techno-economic calculations of small-scale hydrogen supply systems for zero emission transport in Norway

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ABSTRACT

In Norway, where nearly 100% of the power is hydroelectric, it is natural to consider water electrolysis as the main production method of hydrogen for zero-emission transport. In a startup market with low demand for hydrogen, one may find that small-scale WE-based hydrogen production is more cost-efficient than large-scale production because of the potential to reach a high number of operating hours at rated capacity and high overall system utilization rate. Two case studies addressing the levelized costs of hydrogen in local supply systems have been evaluated in the present work: (1) Hydrogen production at a small-scale hydroelectric power plant (with and without on-site refueling) and (2) Small hydrogen refueling station for trucks (with and without on-site hydrogen production). The techno-economic calculations of the two case studies show that the levelized hydrogen refueling cost at the small-scale hydroelectric power plant (with a local station) will be 141 NOK/kg, while a fleet of 5 fuel cell trucks will be able to refuel hydrogen at a cost of 58 NOK/kg at a station with on-site production or 71 NOK/kg at a station based on delivered hydrogen. The study shows that there is a relatively good business case for local water electrolysis and supply of hydrogen to captive fleets of trucks in Norway, particularly if the size of the fleet is sufficiently large to justify the installation of a relatively large water electrolyzer system (economies of scale). The ideal concept would be a large fleet of heavy-duty vehicles (with a high total hydrogen demand) and a refueling station with nearly 100% utilization of the installed hydrogen production capacity.

Introduction

The supply of hydrogen as a transportation fuel is challenging, especially if the hydrogen is to be produced locally based on renewable energy sources. To claim zero emission in the full value chain (from production to utilization), it is necessary to avoid CO_2-emissions from the production and distribution of hydrogen. As pointed out in a previous study [1] there are several factors making Norway a suitable country for introduction of hydrogen for zero emission transport, including the high untapped potential for wind power and the very high fraction (nearly 100%) of hydroelectric power. These conditions also make it natural to consider water electrolysis (WE)

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as the main production method of renewable hydrogen. Water electrolysis is the key technology for *Power-to-Gas* concepts and is thus expected to play a major role in future energy systems which need to store excess energy coming from renewable and intermittent power sources [2,3].

In a startup market with low demand for hydrogen, one may find that local small-scale WE-based hydrogen production is more cost-efficient than regional large-scale production because of the potential to reach a high number of operating hours at rated capacity and high overall system utilization rate. This hypothesis is part of the motivation behind the feasibility studies carried out the last few years addressing hydrogen production at small-scale hydroelectric power stations in Norway [4–7]. The rationale, from the plant owner's point of view, is that it may be more profitable to convert the electricity to hydrogen rather than to sell it directly to the grid, particularly during periods with low spot prices. Local hydroelectric power can avoid being subject to electricity tax, grid fees, or electricity certificates, if it is operated in stand-alone power mode. If such a power plant is dedicated for hydrogen production, the cost of connecting to the local grid can be saved altogether.

The decision on whether a hydrogen refueling station (HRS) is to be established on the production site, or if the hydrogen should be compressed and transported to a nearby refueling station is influenced by the strategy on how to build up a nationwide hydrogen infrastructure in Norway. One strategy is to establish a national network of 700 bar HRSs as soon as possible so that the market for fuel cell electric vehicles (FCEVs) can be allowed to grow faster, while another approach is to focus on establishing stations for captive fleets, such as trucks and buses, as this will ensure high utilization of refueling capacity and predictable returns on investment in the startup market [8]. In most cases the answer will depend on geographical location and several other factors and is therefore normally a decision made on a case-by-case basis. Yet, several general models and strategies for the deployment of hydrogen infrastructures in countries and regions around the world have been proposed in numerous studies over the years [1,9–15], and a few high-level techno-economic studies have attempted to evaluate the cost efficiency of the various supply schemes and technologies [16–18].

In this paper we present a more detailed techno-economic system analyses of two different small-scale hydrogen supply systems in Norway based on water electrolysis. The first Case Study evaluates the possibility of producing hydrogen at the hydroelectric power plant *Rotnes* in Nittedal, Norway and builds on a report published by Institute for Energy Technology in 2017 [4]. The economic feasibility of establishing and operating a local hydrogen production facility by a small-scale hydroelectric plant with a maximum power output of 200 kW and a 60% utilization rate is addressed. The cost efficiency of installing a 700 bar HRS at the plant is furthermore compared to selling compressed hydrogen to a nearby station, and hydrogen cost sensitivity analyses of spot price variations and public support on CAPEX are carried out.

The second Case Study focuses more on the end users' perspective as it addresses the techno-economics of a HRS dedicated to a fleet of heavy duty vehicles. In this case the envisaged hydrogen station is owned and operated by a trucking company and offers refueling at 350 bar only. The station is dimensioned according to the fleet size to ensure full capacity utilization, and by designing the dispenser system for *time fills* [19], unattended overnight refueling can be introduced and very small hydrogen buffer storage volumes installed. For this station configuration we investigate the levelized cost of refueling hydrogen for various fleet sizes and compare a refueling facility supplied by on-site hydrogen production to one which is supplied by trailers from a regional production plant.

The most important output variable of these case studies is the levelized cost of dispensing 1 kg hydrogen into a FCEV. This cost is derived from the average total capital and operating cost (CAPEX and OPEX) of producing, compressing and refueling hydrogen over the project's lifetime, divided by the total hydrogen dispensed over that lifetime. The future cost savings based on learning curves and economies of scale have not been considered in this study, as the intention has been to inform today's stakeholders and decision makers of the expected near-term costs of hydrogen refueling for different supply chains based on the existing and state-of-the art technology.

Methodology and assumptions

A techno-economic modelling tool which can be used to estimate the costs of different designs of water electrolysis-based hydrogen refueling stations on a case-by-case basis has been developed in the program Engineering Equation Solver (EES). The simulation tool can be adjusted and used to access the techno-economics of a wide range of RE-based water electrolyzer systems, including hydrogen compression, storage and dispensing systems. The main technical performance parameters (e.g. WE efficiency, lifetime, auxiliary power needs) and cost functions (e.g. specific costs as a function of rated power or flow rates) for the main systems and key pieces of equipment are entered into the model, in addition to a set of economic parameters (e.g. electricity price, interest rate, project lifetime). From this the model calculates the total CAPEX and OPEX, and eventually the overall hydrogen cost (NOK/kg) for different operating scenarios (e.g. different load profiles or electricity prices).

The supply chains and main system components which have been evaluated are schematically shown in Fig. 1 below. The HRS system configuration shown in the upper part of Fig. 1 is designed for a dual-use hydrogen station serving both passenger cars with on-board tanks at 700 bar and heavy duty vehicles with tanks at 350 bar. This refueling system is relevant for Case Study 1 addressed in Chapter 3.1 (hydrogen production from a small-scale hydroelectric power plant, with or without local HRS) and includes a dry running piston-type compressor which feeds hydrogen from the medium pressure storage bank to a high-pressure storage at about 900 bar. The HRS system configuration shown in the bottom part of Fig. 1 shows a refueling system designed for heavy duty vehicles refueling at 350 bar and is the one considered in Case Study 2 (HRS for trucks, with or without on-site hydrogen production). When the gas in this case is produced by an on-

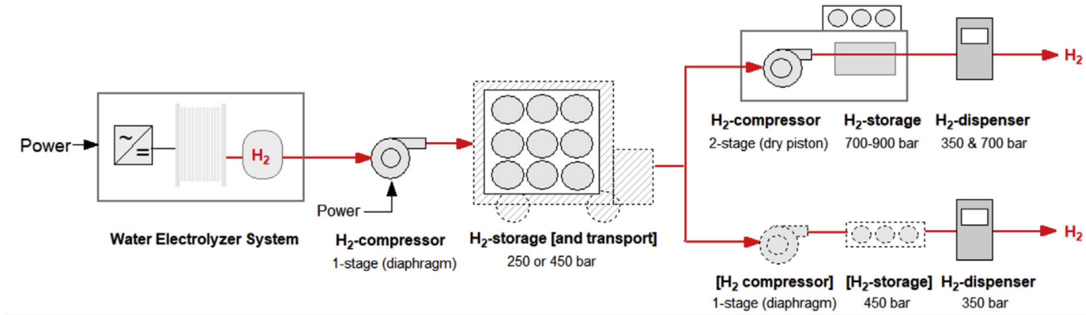

Fig. 1 – The hydrogen supply chains and key system components evaluated in the Case Studies.

site WE-unit, only one compressor (directing the gas to a 450 bar storage) is needed.

The standards for hydrogen refueling of passenger vehicles (SAE J2601) prescribes the precooling of hydrogen to - 40 °C to allow for fast fueling into a 700 bar storage without overheating the vehicle's tank and thus ensure a more complete fill. This pre-cooling, which requires additional equipment and energy [20], is not necessary for the slow refueling (flow rate ≤ 1.8 kg/min [19]) of hydrogen at 350 bar. Hence, the complexity and energy requirement for the considered 350 bar systems are lower than that for the 700 bar systems.

When the hydrogen refueling stations are supplied by trailers from off-site hydrogen production plants (a supply scheme which is evaluated in both Case Studies), the gas is assumed to be transported according to the X-store concept of Hexagon xperion [21]. This comprises a module of composite tanks with 345 kg of hydrogen at 250 bar which is unloaded at the station in exchange of an empty module. The advantage of composite tanks is that they weigh much less than steel tanks and are therefore significantly easier to handle and transport. The transport of hydrogen from the production site to the refueling station is covered by the regulations of overland transport of dangerous cargo, and the hourly rate for transport of compressed hydrogen has been estimated by Oslo Transportsentral to be around 1200 NOK [22]. By assuming that one assignment (including loading, transport and unloading) takes 5 h, the total cost of transport will amount to 6000 NOK (excl. VAT and road toll) and the specific cost for a trailer with a payload of 345 kg hydrogen will thus be 17 NOK/kg H_2.

The techno-economic models employed in this study are based on up-to-date technical performance data obtained from leading water electrolyzer companies and other hydrogen technology suppliers around the world, as well as cost data collected in various projects conducted at IFE over the past few years. All figures have been controlled against data known from public studies on water electrolysis [23,24] and hydrogen stations [17,18]. All costs are furthermore presented in Norwegian kroner (NOK) using exchange rates of 8.5 NOK/USD and 9 NOK/EUR.

Figs. 2 and 3 below shows the specific capital costs of water electrolyzers and hydrogen compressors, respectively, as a function of capacity. These data, based on quotations from suppliers, were collected in connection with Task 33 of IEA's Hydrogen Technology Program [25] and first presented at ICE 2017 [26]. The figures highlight the importance of economies of scales by moving from small to medium capacities, and hence the intrinsic cost-inefficiency of small-scale systems such as those studied herein. Note that for an intermittent energy source (such as the hydroelectric power plant considered in Case Study 1), water electrolysis technology based on polymer electrolyte membranes (PEM) is preferable over the alkaline technology due to the superior ability to handle variable power production. In general, the PEM-technology has a higher specific investment cost than alkaline water electrolyzer technology [24], but the collection of quotes from key water electrolyzer providers interestingly revealed that for the smallest systems, the cost difference between the two technologies is marginal (c.f. orange vs. blue symbols in Fig. 2).

For the hydrogen pressure vessels, we assume storage costs of 6300, 8100 and 19800 NOK/kg for tanks rated for 250, 450 and 900 bar, respectively. For the dispenser we assume a cost of 1.17 million NOK for the 350 bar-system and 1.62 million NOK for the 700 bar-system.

The economic assumptions made in the system simulations are summarized in Table 1. Project costs such as planning, civil works, connecting to water and electricity etc. are included in the installation costs, and assumed to be 10% of the CAPEX. The project lifetime is set to 10 years, which corresponds to the estimated lifetime of a water electrolyzer stack [27,28]. Sensitivity analyses shows that if a payback time of only 7 years had been assumed, the hydrogen refueling costs (NOK/kg) would increase by 20–30% compared to those presented herein. An

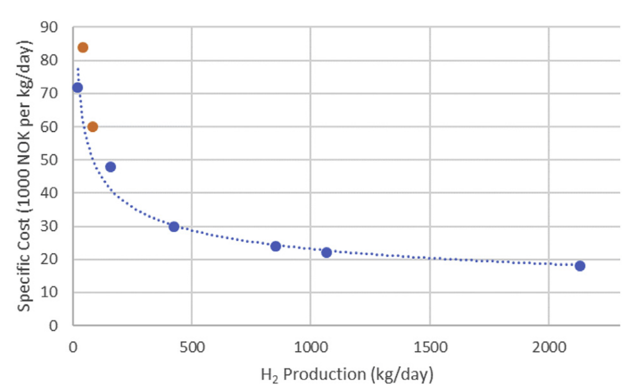

Fig. 2 – Specific capital costs of alkaline water electrolyzer (blue symbols) and PEM water electrolyzer systems (orange symbols). The dashed line represents the best fit to the alkaline WE cost data. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

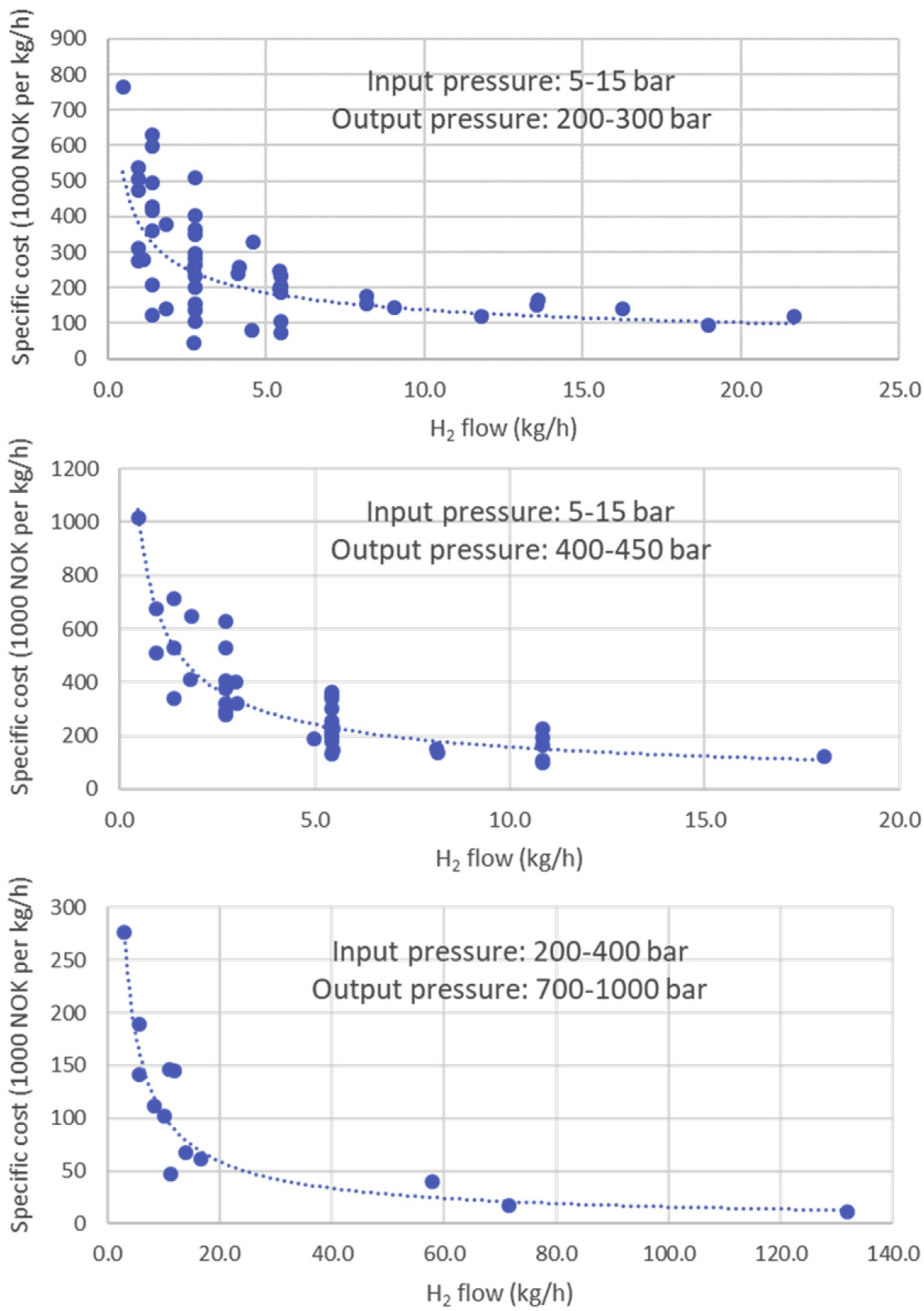

Fig. 3 – Specific capital costs of compressors for various input and output pressures.

interest rate variation of ±2% would on the other hand cause the hydrogen refueling cost to vary by ± 5%.

Results

CASE STUDY 1: hydrogen production from a small-scale hydroelectric power plant

Power available for hydrogen production

The power produced at the hydroelectric power plant Rotnes in Nittedal in the period 2009–2015 is shown in Table 2 and divided into four different power ranges from 0 to 200 kW. The number of operating hours for each effect range is listed in parenthesis. The hydro plant produces power about 8000 h per year, and by installing a PEM-based water electrolyzer system, which can be operated continuously between 50 and 200 kW (i.e. minimum part-load operation of 20–25% of nominal capacity assumed), about 7500 h of hydrogen production can be achieved annually.

The maximum power available from the hydroelectric plant is about 180 kW and the installed production capacity is therefore assumed to be 200 kW nominal power. The potential for hydrogen production in the various power ranges is

Table 1 – Economic assumptions made in the system simulations.

Project lifetime (Years)	10
Interest rate	5%
Stack lifetime (h)	90 000
Installation costs (of CAPEX)	10%
Operation & Maintenance costs (of CAPEX)	4%
Redundancy on compressors	100%

depicted in Table 3 and has been calculated based on the available power and the number of operating hours, assuming the average specific energy consumption for production and compression of hydrogen is 87 kWh/kg H_2 (from 82 kWh/kg at 200 kW to 108 kWh/kg at 50 kW). The expected average annual hydrogen production amounts to about 12 000 kg, corresponding to a water electrolyzer capacity utilization of 60% (1035 MWh/1750 MWh). A station with this capacity would be able to serve about 100–200 FCEVs [29].

Concepts and scenarios

The Rotnes hydroelectric power station has the advantage of being located relatively close to existing hydrogen stations in the Oslo region, and distribution of pressurized hydrogen to one of these stations may thus be a good option. Another possibility is to install a local HRS at the power plant. This will eliminate the need for distribution and transport of hydrogen, but at the same time increase the investments and operating costs. A dual-use hydrogen station, serving both heavy-duty trucks (350 bar) and passenger cars (700 bar), will give the highest flexibility with respect to utilization. On this basis, two business concepts for the small-scale hydroelectric plant is evaluated, namely one in which pressurized hydrogen is sold to a nearby refueling station (Concept 1.1) and one in which an HRS is installed on-site (Concept 1.2):

- Concept 1.1: Local hydrogen production and compression, *without* HRS
- Concept 1.2: Local hydrogen production and compression, *with* HRS

Electricity represents the most important variable cost when considering hydrogen production from water electrolysis, and there are potential cost savings associated with installing the hydrogen generator *at* the local power station (ref. discussion in Section Methodology and assumptions). The cost of using local power for hydrogen production can in this case be considered the equivalent to the loss of income by refraining from selling the electricity to the grid. The effect of variations in spot price on the hydrogen production costs has therefore been investigated: a spot price of 0.25 NOK/kWh (based on historical spot prices in this region of Norway [30]) is compared to a hypothetical high tariff of 0.45 NOK/kWh that one may see in a few years' time when the new transmission lines from Norway to the European continent and the United Kingdom are completed.

In an early market phase, public support is considered necessary for the establishment of new hydrogen infrastructure [12]. Projects such as the ones described in this study may be eligible for support from various public organizations in Norway, for example Enova SF, which is a public enterprise responsible for the promotion of environmentally friendly production and consumption of energy. In 2017 Enova issued a program to support the establishment of hydrogen infrastructure [31], and in the present study this is used to calculate the levelized cost of hydrogen including public support on CAPEX. The following sensitivity analyses wrt. electricity

Table 2 – The energy (MWh) available for hydrogen production at Rotnes between 2009 and 2015. The number of operating hours in the respective effect ranges is given in parenthesis.

Year	0–49 kW	50–99 kW	100–149 kW	150–200 kW	Total MWh and no. of operating hours
2009	23 (679)	106 (1512)	411 (3135)	504 (3101)	1044 (8427)
2010	18 (546)	178 (2435)	269 (2072)	572 (3462)	1037 (8515)
2011	22 (1003)	61 (832)	315 (2299)	611 (3656)	1008 (7790)
2012	6 (213)	44 (534)	544 (4112)	562 (3520)	1156 (8379)
2013	20 (855)	111 (1410)	338 (2551)	484 (2960)	954 (7776)
2014	14 (451)	80 (1016)	556 (4103)	456 (2821)	1107 (8391)
2015	23 (105)	23 (291)	382 (2805)	640 (3927)	1068 (7128)
Average	**18 (550)**	**86 (1147)**	**402 (3011)**	**547 (3350)**	**1053 (8058)**

Table 3 – Estimated hydrogen production (kg) for a plant with a maximum capacity of 60 kg/day (200 kW), based on historical power production (2009–2015).

Year	0–49 kW	50–99 kW	100–149 kW	150–200 kW	Total kg
2009	0	1071	4725	6072	11 868
2010	0	1799	3094	6886	11 779
2011	0	612	3621	7356	11 589
2012	0	441	6252	6773	13 466
2013	0	1125	3888	5835	10 848
2014	0	810	6388	5498	12 696
2015	0	234	4388	7715	12 337
Average	**0**	**870**	**4622**	**6591**	**12 083**

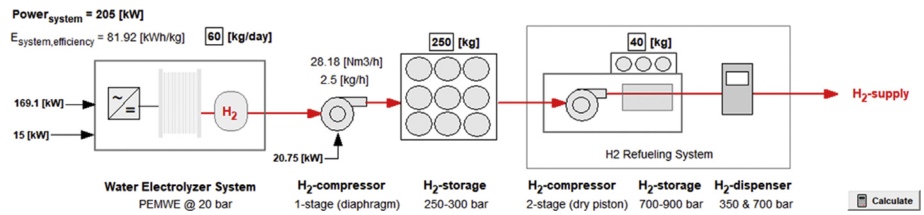

Fig. 4 – The rated capacity and energy consumption of supply chain key components in Case Study 1 (with on-site HRS).

prices and public support for the two different concepts in Case Study 1 is therefore performed:

A High electricity costs (0.45 NOK/kWh) with 50% public support on CAPEX
B High electricity costs (0.45 NOK/kWh) without public support on CAPEX
C Low electricity costs (0.25 NOK/kWh) with 50% public support on CAPEX
D Low electricity costs (0.25 NOK/kWh) without public support on CAPEX

System description

Fig. 4 shows the graphical user interface of the modelling tool for the hydrogen supply system addressed in Case Study 1. It depicts the rated capacities and energy consumption of the various components of a delivery system with an installed capacity of 205 kW (corresponds to 60 kg/day at full utilization). Note that the calculated system efficiency of 82 kWh/kg H_2 includes the energy consumption of a small PEMWE in a 15 feet container with all auxiliaries, as well as the energy required for H_2 compression by the diaphragm compressor with output pressure of 250 bar. The hydrogen flow is only 2.5 kg/h, significantly driving up the costs of the compressors as well (ref. Fig. 3).

Hydrogen costs

In Fig. 5 the contribution of the various system key components to the CAPEX are shown for Concept 1.1 (left) and Concept 1.2 (right). The total CAPEX amounts to 8600 kNOK and 11 800 kNOK, respectively. It should be noted here that the dual pressures refueling system in Concept 1.2 includes the high-pressure storage tanks and the second compressor.

The calculated levelized costs of hydrogen, assuming a utilization rate of 60%, are summarized for the different cases and scenarios in Table 4. For Concept 1.1 (the option without a local HRS) the hydrogen cost varies between 83 and 125 NOK/kg, while when adding an on-site HRS, the cost ranges from 105 to 157 NOK/kg. By comparison, today's retail price for hydrogen in Norway is fixed at 72 NOK/kg, excl. VAT (pump price: 90 NOK/kg) to be gasoline-equivalent [32].

For Concept 1.1 one must keep in mind that to evaluate the cost of actually refueling hydrogen, the transportation costs and the operating expenses of the refueling station must be covered as well. Assuming weekly deliveries of 230 kg H_2 (corresponding to the average weekly production), this gives a transportation cost of 25 NOK/kg (ref. Section Methodology and assumptions).

According to the results shown in Table 4, it will be impossible to sell hydrogen with a profit in Case Study 1 (and similar cases with small-scale distributed renewable energy-based hydrogen production), particularly in an early market when there are few vehicles available. Hence, one way to evaluate the potential profit is to look at the alternative operating costs. In a commercial market with many fuel cell vehicles and several HRS in operation we estimate that HRS operators will need to charge at least 20 NOK/kg H_2 to cover basic operating expenses (excluding cost of hydrogen). When

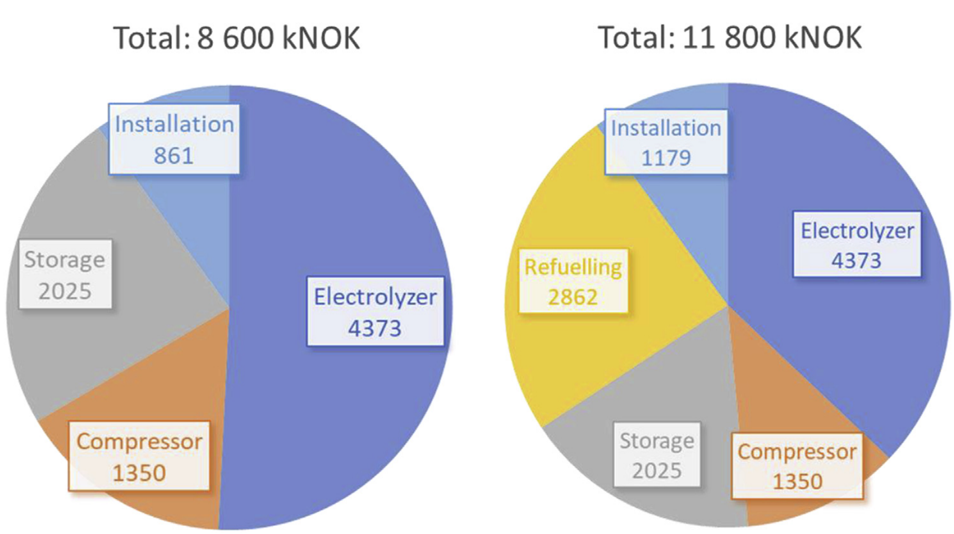

Fig. 5 – Cost breakdown of CAPEX (in kNOK) for the hydrogen production system considered in Case Study 1. The production plant without HRS (left) is compared to a plant with HRS installed on-site (right).

Table 4 – Levelized cost of producing, compressing and refueling hydrogen at Rotnes power station.

	Scenario A	Scenario B	Scenario C	Scenario D
	0.45 NOK/kWh, 50% public support	0.45 NOK/kWh, no public support	0.25 NOK/kWh, 50% public support	0.25 NOK/kWh, no public support
Concept 1.1 H2 for distribution	83 NOK/kg	125 NOK/kg	66 NOK/kg	109 NOK/kg
Concept 1.2 With local HRS	99 NOK/kg	157 NOK/kg	83 NOK/kg	141 NOK/kg

the hydrogen transport costs (25 NOK/kg) and HRS operating costs (20 NOK/kg) are included, the calculated levelized costs for the most favorable Scenario in Concept 1.1 (Scenario C at 66 NOK/kg) reaches 111 NOK/kg, which is almost 40 NOK/kg more than today's hydrogen retail price.

CASE STUDY 2: HRS for small fleet of heavy-duty vehicles

System description

The feasibility of investing in an HRS for a small fleet of heavy-duty trucks is evaluated in this case study where two different HRS concepts are assessed and compared: Hydrogen from an on-site water electrolyzer production unit (Concept 2.1) and hydrogen delivered by trailers (Concept 2.2). Fig. 6 illustrates the system considered in Concept 2.1 and includes the rated capacities and typical energy consumption of the key components. In this example the hydrogen production and refueling facility has a daily turnover of 90 kg H_2 (corresponding to a fleet of 3 trucks, assuming each truck carries 30 kg H_2 [13]). It is furthermore assumed that unattended night fills take place so that for Concept 2.1 the size of the hydrogen buffer storage can be minimized to only 50% of the daily consumption. In Concept 2.2, on the other hand, the hydrogen buffer storage capacity is assumed to correspond to the payload of the delivery truck, i.e. 345 kg.

In Case Study 2, the hydrogen production capacity of the water electrolyzer is 100% utilized, as opposed to 60% in Case Study 1. This is based on the assumption that small-scale on-site water electrolyzer systems and corresponding hydrogen systems can be designed and dimensioned to meet the exact hydrogen demand for a given fleet of vehicles. Furthermore, the cost of electricity in this case includes both taxes and grid fees, albeit the power required for the water electrolysis is exempted from electricity tax (amounting to 0.166 NOK/kWh in 2018) [33]. From this it can be assumed that the cost of power to run the auxiliary systems is 0.45 NOK/kWh, while the cost of power for water electrolysis is 0.30 NOK/kWh.

Finally, it should be noted that in the case of centralized hydrogen production and bulk delivery of hydrogen (Concept 2.2), it is assumed that all of the hydrogen comes from an off-site alkaline water electrolyzer plant with a hydrogen production cost of 30 NOK/kg. This cost is calculated based on a standard industrial water electrolyzer plant with a hydrogen production rate of 1000 kg H_2/day (rated capacity of 2.6 MW) and full capacity utilization. In addition, the costs of transporting hydrogen from the plant to the HRS is assumed to be 17 NOK/kg (somewhat lower than 20 NOK/kg in Case Study 1 due to more efficient hydrogen distribution systems). Hence, the total cost of supplying hydrogen from a centralized hydrogen production plant to the HRS is 47 NOK/kg, which adds to the OPEX of the hydrogen refueling station.

Hydrogen costs

Fig. 7 shows the breakdown of the capital costs for the key components and sub-systems required in Concept 2.1 with on-site production (left) and Concept 2.2 with truck delivery (right). The total CAPEX for the two concepts is 9600 kNOK and 8500 kNOK, respectively. It is interesting to observe that the cost savings of the system without an on-site water electrolyzer are nearly canceled out by the large and costly hydrogen storage based on composite pressure vessels. A comparison of Fig. 7 with Fig. 5 (right) shows that significant cost savings can be made by switching from 700 bar to 350 bar refueling systems (the CAPEX of the 700 bar refueling system includes both the high pressure storage and the extra compressor).

The bar chart in Fig. 8 shows the total annual CAPEX and OPEX (values on the left-hand y-axis) as a function of daily turnover for the two concepts of on-site production and hydrogen delivery. The OPEX is divided into the three most costly elements: hydrogen procurement, hydrogen transport and electricity (see figure legend). The connected single points (circles and triangles) plotted in the figure (values on the right-hand y-axis) show the levelized cost per kg dispensed hydrogen as a function of daily turnover for the two concepts.

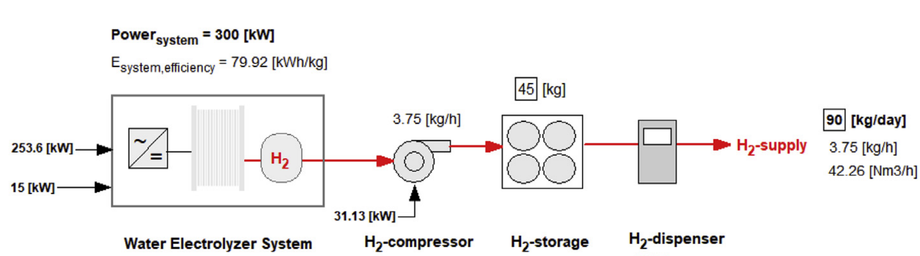

Fig. 6 – The rated capacity and energy consumption of supply chain key components in Case Study 2.

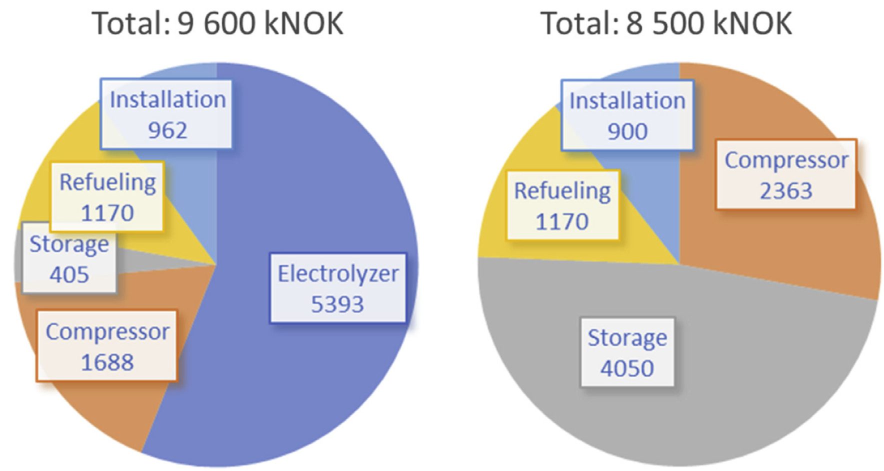

Fig. 7 – Cost breakdown of CAPEX (in kNOK) for 350 bar HRS with on-site hydrogen production (left) and hydrogen delivered by truck (right). The hydrogen turnover for both system concepts is 90 kg/day.

The total annual costs increase with increasing fleet size (larger installed capacities and increased operating expenses), while the levelized costs of hydrogen decreases due to lower specific investment costs (Figs. 2 and 3) and lower relative energy consumption (energy per kilogram of hydrogen) for the auxiliary systems. The results show that despite the relatively low HRS investment costs for delivered hydrogen (Fig. 7, right), the increased operating expenses associated with the procurement and transport of hydrogen (30 NOK/kg and 17 NOK/kg, respectively) makes this option a less favorable business case overall compared to on-site hydrogen production. The results also show that in a fleet of 5 fuel cell trucks (a daily hydrogen turnover of 150 kg), the levelized hydrogen fueling cost can reach 71 NOK/kg at an HRS based on delivered hydrogen and 58 NOK/kg at an HRS with on-site production.

Summarizing discussion

Capacity utilization

The techno-economic analyses performed in the two case studies described above show that the cost-efficiency of small-scale hydrogen supply systems is significantly influenced by the scale of the hydrogen production plant and the refueling option (350 or 700 bar). Another important factor that strongly affects the hydrogen production costs is the utilization of installed capacity. The capacity utilization in Case Study 1 and 2 is assumed to be 60% and 100%, respectively. The consequences of this is discussed in some more detail below.

In Fig. 9 the levelized cost of refueling hydrogen is plotted as a function of utilization rate for 350 and 700 bar refueling systems. The figure shows that the cost of refueling hydrogen at the hydroelectric power station *Rotnes* with an installed capacity of 200 kW drops from 141 NOK/kg at 60% utilization (*Concept 1.2, Scenario D* in Table 4)–93 NOK/kg in an ideal case where the utilization rate is brought up to the theoretical maximum (100%). This can only be realized by buying electricity from the grid to cover the gap between the full installed WE capacity (100% of rated power) and the power available at the local hydroelectric plant.

A similar point can be made for Case Study 2: If the daily hydrogen demand at a 300 kW (i.e. 90 kg/day) heavy duty facility is only 60 kg/day, the hydrogen refueling cost will increase from 63 NOK/kg at full utilization to 85 NOK/kg at 66 % utilization. In this case, a better alternative would be to dimension the WE for the needed capacity (200 kW), as this would yield a hydrogen cost of only 68 NOK/kg.

These results highlight the importance of achieving the highest possible utilization of the installed capacity in hydrogen stations. The results also show that although there are significant economic advantages associated with large centralized hydrogen production plants, these benefits may be drastically reduced if the plants are not fully utilized. In a startup market it is therefore advisable to install smaller refueling stations with on-site production units for customers with a predictable and steady hydrogen demand (such as fleets of heavy duty vehicles). Water electrolyzer systems are modular and the station capacity can be gradually increased as the number of users grow.

Comparison with fossil fuel costs

It is important to keep in mind that the calculated cost of refueling hydrogen depends on the underlying economic and technical assumptions such as the interest rate, the project lifetime and specific costs of key components, and the results reported in this study must therefore be considered to be estimates. Nevertheless, it is interesting to compare hydrogen cost estimates to fossil fuel options.

As shown in Case Study 1 (local HRS for cars) the cost of refueling hydrogen produced at the small-scale hydroelectric power plant (Rotnes) far exceeds the retail price for hydrogen (which is fixed at 72 NOK/kg, excl. VAT in order to be gasoline-equivalent [32]) and will not be able to compete in today's market. In Case Study 2 (local HRS for fleet of trucks), on the other hand, there may be a larger chance for hydrogen to compete with conventional fuels, (in this case diesel). If it is assumed that a trucking company gets a volume discounted

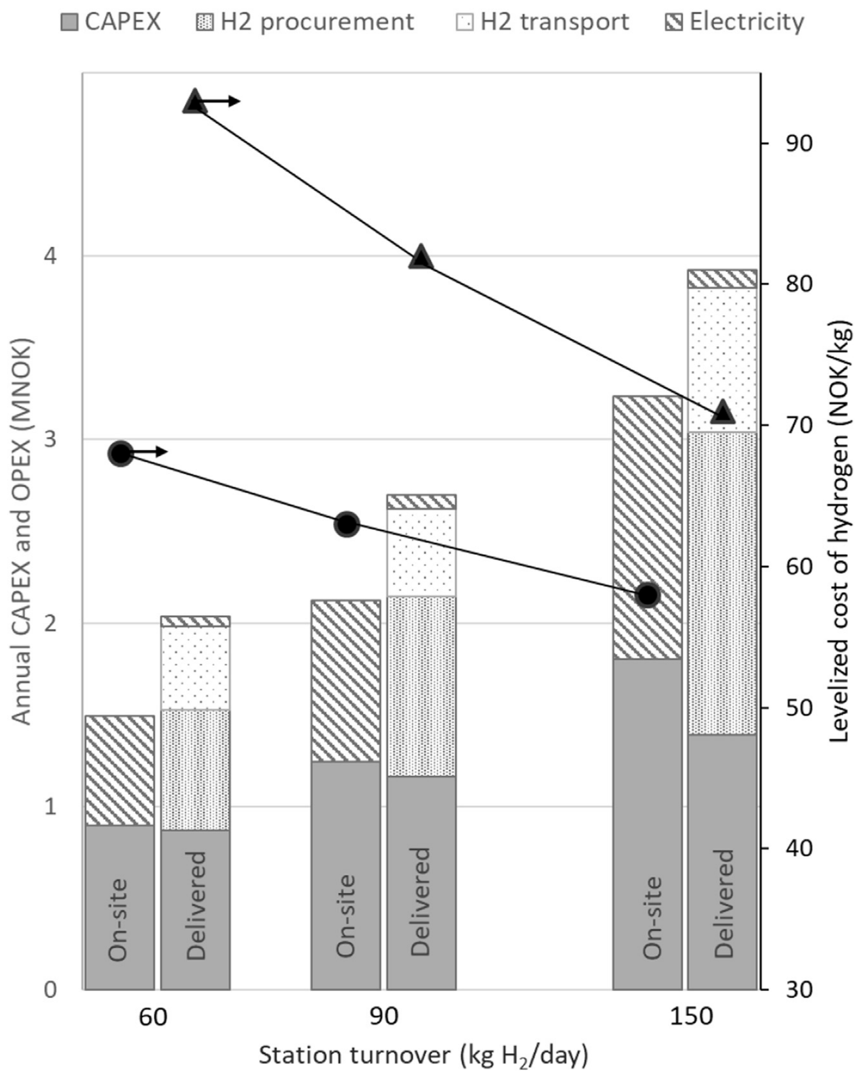

Fig. 8 – Annual CAPEX and OPEX (bar chart) and levelized cost of hydrogen (connected single points) as a function of station turnover for the two HRS concepts considered in Case Study 2. Circle symbols represent on-site production and triangle symbols truck-delivery of hydrogen.

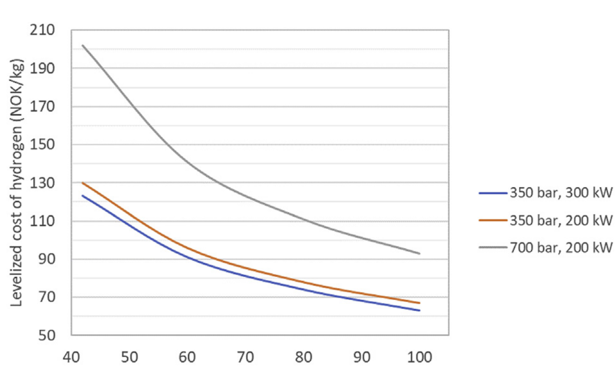

Fig. 9 – The levelized cost of hydrogen for different refueling systems and capacities as a function of utilization rate.

diesel price of 11.13 NOK/liter [34] and that the average fuel consumption is 3.3 L diesel/10 km [35] and 0.7 kg H_2/10 km (39 and 55% energy efficiency, respectively), it can be estimated that the cost of refueling hydrogen needs to be 52 NOK/kg or less in order to be cost-competitive with diesel. This implies that the system configurations assumed in Case Study 2 also need to be scaled up to be cost-efficient (i.e., increase fleet of trucks), and that public support probably will be needed in a startup market, until economies of scale is reached.

Conclusions

The techno-economic calculations performed in this study show that the hydrogen refueling cost at a small-scale hydroelectric power plant in Norway (e.g., Rotnes) will significantly exceed today's retail price for hydrogen. This is mainly due to the small scale (200 kW) and low average utilization rate (60%) of the load-following water electrolyzer. Even if the utilization rate is brought up to the theoretical maximum (100%), it will be difficult to develop economically viable hydrogen refueling systems without public support schemes. In comparison, a heavy duty HRS with an on-site water electrolysis unit serving a fleet of trucks seems to be a better business case. This is because a predictable and steady hydrogen demand is ensured and because the investment and operational costs of a 350 bar refueling systems are lower than for 700 bar systems.

The results in this study clearly show that although there are significant economic advantages associated with large and cost-efficient centralized hydrogen production plants, these benefits may be drastically reduced if the plants are not fully utilized. The costs for transporting and distributing hydrogen from the centralized plant to the hydrogen station are furthermore relatively high. The study shows that there is a relatively good business case for local water electrolysis and supply of hydrogen to captive fleets of trucks in Norway, particularly if the size of the fleet is sufficiently large to justify the installation of a relatively large water electrolyzer system (economies of scale). The ideal concept would be a large fleet of heavy-duty vehicles (with a high total hydrogen demand) and a refueling station with nearly 100% utilization of the installed hydrogen production capacity.

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