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# Sector coupling potential of wind-based hydrogen production and fuel cell train operation in regional rail transport in Berlin and Brandenburg

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## HIGHLIGHTS

- Geocost-model to assess local wind hydrogen production for fuel cell powered trains.
- Sufficient track-adjacent windmills in Brandenburg to provide FC train operation.
- Minimum costs of 6,4 €/kg $H_2$ for on-site electrolysis hydrogen for the study region.

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## ABSTRACT

As the transport sector is ought to be decarbonized, fuel-cell-powered trains are a viable zero-tailpipe technology alternative to the widely employed diesel multiple units in regional railway service on non-electrified tracks. Carbon-free hydrogen can be provided by water-electrolysis from renewable energies. In this study we introduce an approach to assess the potential of wind-based hydrogen for use in adjacent regional rail transport by applying a GIS approach in conjunction with a site-level cost model. In Brandenburg about 10.1 million train-km annually could be switched to fuel cell electric train operation. This relates to a diesel consumption of appr. 9.5 million liters today. If fuel cell trains would be employed, that translated to 2198 annual tons hydrogen annually. At favorable sites hydrogen costs of approx. 6.40 €/kg - including costs of hydrogen refueling stations - could be achieved. Making excess hydrogen available for other consumers, would further decrease hydrogen production costs.



## Introduction

Hydrogen based sector coupling is widely regarded as an important part of the German 'Energiewende' meaning a transition from a carbon based to a carbon neutral energy system by altering the energy sources, energy efficiencies and market processes. The concept of 'Verkehrswende (i.e. implementing alternative vehicle types, drivetrains and traction technologies and most importantly switching transport modes) was later added to integrate the energy and transport sector and therefore accelerate a carbon-free economy. Employing hydrogen-fueled transportation is one way to integrate and couple the transport sector with the energy sector.

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Hydrogen transportation and infrastructure in Germany is currently developing. As of June 2020, there have been 89 hydrogen refueling stations (HRS) [1] in an operation mode for road vehicles in Germany. The government's aim is to establish 400 HRSs until 2023 [2]. Additionally, there are several pilot schemes operating bus lines on hydrogen.

About 54% of the German rail network is not electrified [3]. On those non- or partly electrified tracks, diesel-fueled trains (diesel multiple units – DMU) are being operated. Those could potentially be replaced with hydrogen-powered trains (fuel-cell electric multiple units – FCEMU) [4]. Other zero-tailpipe-options include a partial overhead line electrification combined with the operation of battery electric multiple units (BEMU) and a full-line electrification on which electric multiple units (EMU) operated. In 2018 the world's first two FCEMU were put in scheduled passenger service in Germany [5,6]. Recently, several more pilot schemes for hydrogen rail transport have been publicly announced [7–9]. The first large German FCEMU fleets will enter passenger operation in 2021 (14 trains near Hamburg) and 2022 (27 trains near Frankfurt) [4].

Hydrogen is used for a large variety of industrial applications. The most widespread method to produce industrial hydrogen is steam methane reforming (SMR) [10] where hydrogen is extracted from natural gas. Through its dependence on natural gas, this method generates approximately 10 tons of carbon dioxide per ton hydrogen [10]. Fossil free hydrogen can be produced with water-electrolysis if the electrolysis is powered by renewable energy sources. Recently this has often been done in the context of power-to-gas applications (P2G). An established electrolysis technology is the alkaline electrolysis (AEL). However, for P2G applications polymer electrolyte membrane (PEM) electrolysis is considered more suitable due to its potential high power-density and the possible partial-load (and over-load) operation [11,12]. Compared to AEL which is the most mature electrolysis technology PEM is a relatively new technology and therefore more cost intensive than AEL. With increasing market penetration, the prices (and efficiencies) of PEM systems are expected to decrease [13,14].

Buttler & Spliethoff (2018) gave an overview of PEM electrolyzer systems currently available at the market. They state a range of specific energy consumption between 4.4 kWh/Nm$^3$ and 6.5 kWh/Nm$^3$ for a variety of PEM models of various sizes. They also analyzed a running pilot project and stated a system efficiency of 56% (5.4 kWh/Nm$^3$) when operated at rated total power, including rectification and all utilities like cooling, purification and compression. They reported even higher efficiencies when the system was operated in partial load (up to 64% resp. 4,7 kWh/Nm$^3$). Considering the suitability of PEM for railway applications, there has also been research on optimized configurations of hybrid energy systems [15–18].

The major source for renewable energy in Germany is onshore wind power with a share of 15.4% of the German gross electricity consumption [19]. In the scope of the German Renewable Energy Sources Act [20] ('Erneuerbare-Energien-Gesetz' - EEG), newly constructed wind mills from 2000 onwards (and plants constructed before 2000) were warranted a 20 year feed-in compensation ('EEG-Umlage'). In the upcoming years, many windmills will become ineligible to receive EEG-compensation and in many cases further operation will be unprofitable [21] due to low energy market prices. When possible, operating companies usually choose to repower plants in order to operate on higher efficiency.

With the introduction of dedicated wind power areas (Windeignungsgebiete - WEG) in Brandenburg the obstacles to repower windmills have been grown. In appliance with the federal regional planning act (Raumordnungsgesetz – ROG [22]), plants formerly erected outside wind power areas can only continue to operate but cannot be repowered. Accordingly, new alternative schemes for direct marketing of electricity need to be developed [23]. Using windmills to provide energy for water electrolysis directly i.e. with a direct electric transmission cable from the wind park to an electrolyzer would be such an alternative use. In this scenario, windmill operation could be independent from low market prices while regional rail transport could be decarbonized using locally produced wind-energy.

There has been profound research on (renewable) P2G-technologies, discussing the technological and economic state of the art of water electrolysis [11,24–31]. In those studies, the role of excess energy [32–34] for P2G is often discussed and besides P2G other concepts such as power-to-heat and power-to-fuel are usually considered [34,35]. Even though these studies often cover energy system analysis, the main study focus is usually on the technological state and the economic possibilities. Spatial factors are rarely included.

The economic and technical feasibility of hydrogen produced from renewable energy plants [36] specifically for use in transport applications has been analyzed for a variety of application examples, mainly with a focus light duty vehicles and buses [37–41]. Only little attention though has been put to models aimed at investigating onsite-hydrogen electrolysis using wind power specifically for rail applications. However, the use of green hydrogen for regional railways will be realized in a couple of projects for example in Germany (Heidekrautbahn [8,42], Schwarzatalbahn [43]).

Railways are a suitable application for dedicated hydrogen production facilities for a couple of reasons. First, trains consume considerable amounts of energy which is second, well predictable and constant over several years. This improves economies of scales of hydrogen production and storage appliances. That is why, we prove the viability exclusively for train-use first. Subsequently other hydrogen consumers (i.e. busses, fairies, automobile fleets, forklifts, industrial applications, etc.) should be considered as an on-top hydrogen demand, increasing hydrogen production, distribution and HRS economies of scale. However, this is not within the scope of this study.

If an actual local 100%-renewable energy operation (i.e. carbon free transportation) is required (opposing to a balanced renewable scenario) the direct coupling of renewable energy plants to the water electrolysis is one of the only few possible scenarios. Alternatively, BEMU-operation from local renewable energy sources would be possible, however through the volatile and seasonal character of renewable energies, energy-storages would need to be of considerable sizes and reloading of the BEMU traction-batteries would be a logistically challenging task, especially on long routes. Additionally, on remote tracks grids might often not be designed for

appropriate charging rates in BEMU-rail-service. The deterministic energy demand of passenger trains is however well operational with fuel-cell powered trains. Aiming at local carbon free transportation, there are some restrictions to the sources of hydrogen. If electrolyzers would be operated with grid power, only a balanced carbon free operation could be achieved, considering the grid energy mix. Other routes for hydrogen generation (such as industrial SMR) are linked to considerable greenhouse-gas emissions. Carbon-capture-technologies are mostly researched for industrial applications because they faced strong oppositions from public opinion and local protest [44] and are subject to high energy penalties [45].

Most geospatial studies derive possible hydrogen consumption loads from varying demographics or evaluate pipelines and other hydrogen transportation modes between regional centers. For hydrogen infrastructure, namely hydrogen pipelines [46] and hydrogen refueling stations [47], several studies implemented geographical methods, namely geographic information systems (GIS) which are usually embedded in broader economic analyses [48–56]. However, those studies mainly focus on individual road transport and their focus is often macroscopically on a national level.

Recent work in hydrogen rail transport was often commissioned by public federal governments and is mostly published as project reports. These publications are often in the scope of feasibility studies on project scale or of entire federal states [43,58] evaluating the general economic and technological potential. Spatial analysis in this field is rare. The hydrogen considered in these studies does not necessarily originate from fossil free sources.

The German Federal Association for Wind Energy (Bundesverband Windenergie e. V – BWE) has commissioned an analysis on windmill operation after 2020 [21] projecting further operation as economic unfeasible at the current market prices. They project minimal operating costs for aged windmills at approximately 0.03 €/kWh.

We aim to estimate the feasibility and the potentials of hydrogen provision and consumption for and in regional rail passenger service from 100% renewable energy sources. Thereby we i) estimate the quantities of potential wind-hydrogen provision in the study region Berlin/Brandenburg, ii) quantify the hydrogen demand of the regional rail passenger service in the study region and iii) assess the costs of hydrogen for the given demand using a site-specific hydrogen cost model.

## Methodology

The analytical approach of this study is organized as shown in Fig. 1, structured according to the three main objectives stated above. First, we conducted a GIS-based assessment of the current DMU-operation in the study region (Fig. 1, box 1). For this purpose, we pre-selected FCEMU-suited train lines and researched vehicle types, distances and circulations from which we estimated annual diesel consumption and the respective hydrogen consumption for FCEMU operation. After quantifying the hydrogen potential, we localized current diesel refueling stations and determined further possible sites for hydrogen refueling stations. In the second step (Fig. 1, box 2), we assessed the current wind power plants in operation and determine plants suitable for coupled hydrogen production. Therefore, we selected windmills, tested if they are part of a wind park (wind park affiliation) and exemplarily analyzed energy yields for the reference years 2014–2016. In the third step (Fig. 1, box 3) we determined potential sites for electrolysis, using a spatial overlay technique and calculated the specific hydrogen production costs for each potential site, based on a dedicated cost model incorporating the hydrogen demand potential, the wind energy potential, the distances between wind parks and HRS and route characteristics. Finally, we performed a sensitivity analysis on the cost model. An overview of the used input data can be found in Appendix B.

As power source, we considered currently installed windmills in Brandenburg. As described in section Introduction, wind power is the main renewable energy source in the study area with many aging windmills ought to find new marketing models. Additionally, precise data about the installed windmills is available. We considered an isolated off-grid plant scheme to avoid network charges and other EEG restrictions [20] and to ensure a 100% local carbon-free railway operation. Therefore, the hydrogen storage facilities must be dimensioned to ensure full hydrogen availability at all times. As hydrogen consumer we exclusively considered the regional railway passenger trains as these are well predictable. Fig. 2 shows the basic plant concept considered in our model.

### *Assessment of potential hydrogen consumption*

The methodology for assessing the hydrogen potential was conducted in two steps. First, we quantified the operating performance (train-km) and estimated the potential hydrogen consumption. Second, we determined possible spatial locations for the hydrogen refueling stations.

#### *Quantification of current train operating performance*

To quantify current DMU-bond railway services, we preselected all actively operated DMU-railway lines in the study region which are used for passenger railway service. If one of the following points applied, railway lines were excluded from further analysis (also see Appendix A):

i) The track the line is operating on is known to be subject of future electrification, i.e. it is assigned as priority need for track-side electrification in the federal transport plan for 2030 [59].
ii) The not-electrified sections of each line's track are in total shorter than 10 km (in this case, an operation with battery electric driven trains, BEMU, would be more reasonable).
iii) The majority of the track-length is outside of Brandenburg.

The vehicle types, routing and daily train kilometers were specified through a screening of public tender documents and operator publications [60]. The circulation was derived from the timetables of the network operators [61–63] and was

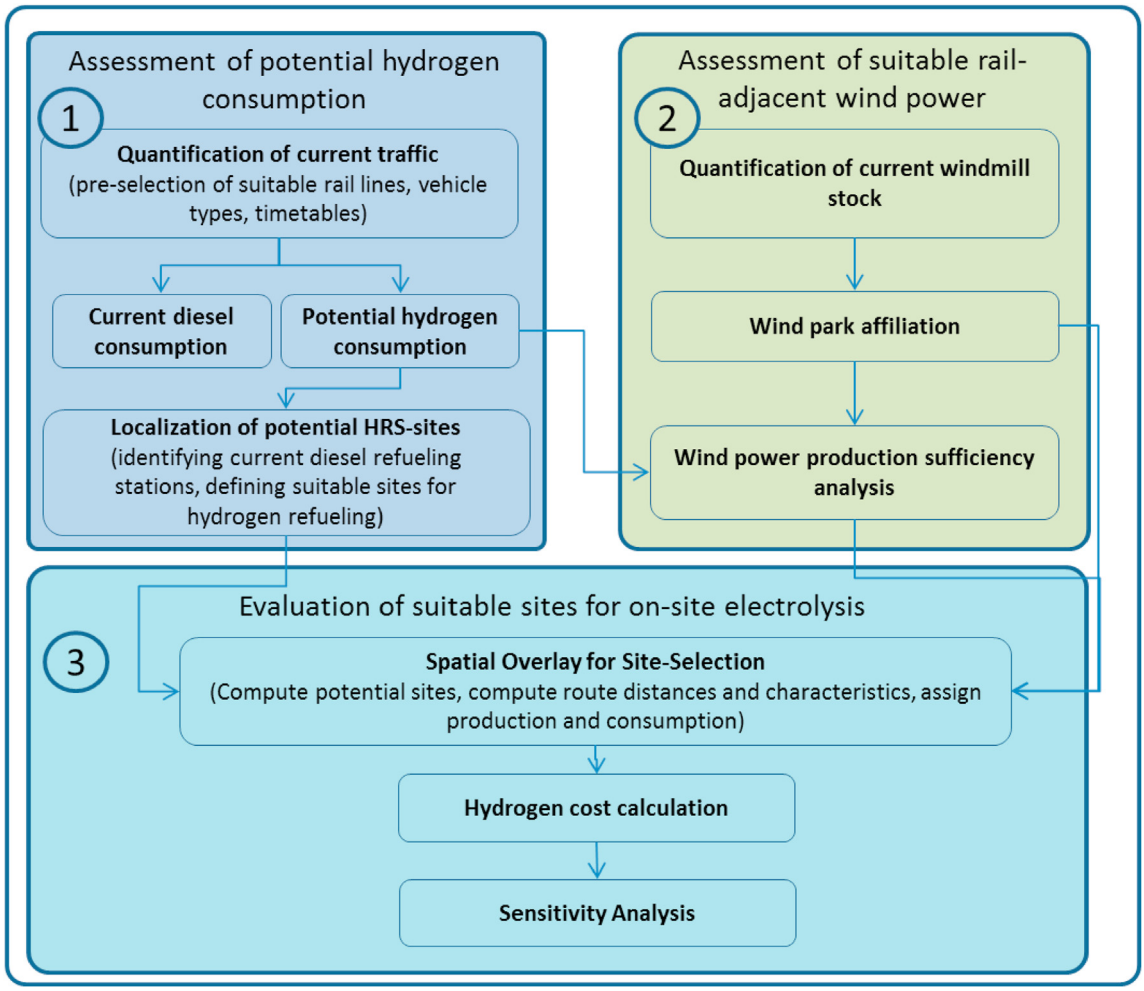


**Fig. 1 – Analytical approach.**


**Fig. 2 – Hydrogen production chain concept.**

averaged over the whole week and year to form a daily average.

Average daily diesel consumption was derived using the standardized methodology to evaluate investments in traffic infrastructure commonly used in Germany [64]. According to this procedure, the vehicle specific diesel consumption per km $b_D$ can be estimated with

$$b_D = (W_k \times e) / 1000 \quad (1)$$

where e is the diesel consumption per 1000 ton-kilometers (see Table 1) and $W_k$ the weight of the train. $W_k$ can be calculated as

$$W_k = W_{k,unladenmass} + W_{k,passenger} + W_{fuel} \quad (2)$$

with $W_{k,\ unladen\ mass}$ being the weight of the empty train k (see Table 2), $W_{k,\ passenger}$ the average weight of the passengers and $W_{fuel}$ the weight of the diesel load. The passenger weight can be calculated as

$$W_{passenger} = S_k \times u \times w_{passenger} \quad (3)$$

with $S_k$ being the number of seats of train k, u being the

**Table 1 – Parameters for calculating average diesel consumption according to the standardized methodology to evaluate investments in traffic infrastructure [64].**

| Parameter | Symbol | Value |
|---|---|---|
| Diesel consumption per 1000 ton-km | e | 10.1 l/km |
| Average diesel weight | $W_{fuel}$ | 1000 kg |
| Average utilization rate (occupied seats) | u | 0.28 |
| Average passenger weight | $w_{passenger}$ | 75 kg |

**Table 2 – DMUs operated in the study region [60] and generic FCEMU for this study.**

| DMU | Seats | Number of cars | Wk, unladen mass[t] |
|---|---|---|---|
| Stadler RS 1 (BR 650) | 70 | 1 | 40 |
| Bombardier Talent (BR 643) | 156 | 3 | 96.5 |
| PESA LINK (BR 632) | 140 | 2 | 95 |
| LVT/S - BR 502/504 | 69 | 1 | 32 |
| Double-deck BR 670 | 78 | 1 | 34.25 |
| Alstom Coradia LINT 41 (BR 648) | 120 | 2 | 68 |
| Stadler GTW (BR 646) | 100 | 2 | 73.3 |
| Lint 27 (BR 640) | 61 | 1 | 41 |
| Siemens Desiro (BR 642) | 124 | 2 | 69 |
| Generic fuel cell electric train (This study) | 120 | 2 | 82 |

average utilization rate in regional rail passenger service and $w_{passenger}$ the average passenger weight.

The daily diesel consumption of the considered train line$B_D$ was then computed with

$$B_D = b_D \times D_d \times DH \tag{4}$$

where $D_d$ represents the daily mileage and DH a factor to consider double-heading or triple-heading (e.g., two or three multiple units coupled together reflecting higher vehicle demands in peak hours). We calculated daily mileages for each railway line using 2019 timetable data.

In order to assess the daily hydrogen consumption for each railway line, we simulated a generic two-car fuel cell train with Jacobs type bogie (empty mass: 82 t, loaded mass: 91 t, 120 seats) on the 82 km long secondary-line RB36 from Frankfurt (Oder) to Königs Wusterhausen. The track is not electrified except for the start and terminus stations. The maximum line speed is 100 km/h and it passes mostly through even terrain. It can be regarded as representative for all lines in Brandenburg being investigated in this study. The RB36 is part of the rail network Ostbrandenburg (see Fig. 5).

Irrespective if DMUs operated today are 1 or 2 car vehicles on the study tracks we assumed a generic 2 car FCEMU for all rail operation for two reasons. First, to have a uniform vehicle applied across all investigated railway lines. And second, (from a vehicle concept view) the integration of the required fuel cell hybrid drivetrain and hydrogen storage components in a 1-car train without compromising the passenger payload is a challenging task (and would require conceptual investigations out of the scope of this paper). This is mainly due to limited space on the vehicle roof for spacious and heavy hydrogen tanks compared to diesel powertrain and storage tanks and axle load limits.

The longitudinal simulation was performed using a direct method solver [65] applying static efficiencies for the fuel cell hybrid drivetrain (fuel cell: 50%, axle gearbox: 97.8%, electric motor: 95%, traction inverter: 97%, DCDC converter: 97.5%, battery charging/recharging: 95%/95%). The simulations yielded an average hydrogen demand of $b_{H2}$ = 0.17 kg H2/km, which was then applied to all lines investigated in this study. The daily hydrogen consumptions for each railway line were calculated with:

$$B_{H2} = b_{H2} \times D_d \times DH \tag{5}$$

The estimated diesel consumption does not take the real-world passenger utilization into account. Instead we use a fixed value per seat (compare Eq. (3)). Following the diesel consumption calculation, the influence of passenger numbers however is low. Table 3 exemplarily shows the diesel consumptions of a DMU with various passenger utilization rates.

*Localization of potential HRS-sites*

To determine suitable sites for hydrogen refueling, we first determined sites at where the installation of HRS sites does not require alterations in the current circulation. Therefore, we mapped the locations of existing diesel refueling stations [67] used for passenger railway service and identified train stations where longer breaks (exceeding 1 h) in passenger operation occur (trains cannot be fueled while passengers are on board) or where trains could be refueled before or after operating hours. We derived those locations from the public timetables. Based on insight of the Brandenburg railway system, we identified additional train stations suitable for hydrogen refueling.

The selected sites were collectively added to a base layer (hereafter HRS base sites). Since refueling stations are often not located directly at the train stations themselves but are often in the vicinity of them, we created a 2-km buffer around the base sites. Within this buffer we set points in a 250 m distance on each railway track available (including industrial tracks and tracks where no DMUs operate). These points represent potential HRS sites (see Fig. 3). We then assigned the aggregated potential hydrogen consumption of the underlying DMU-train connections to each potential HRS.

### *Assessment of suitable rail-adjacent wind power*

After quantifying the potential hydrogen consumption, we assessed the wind power necessary to produce renewable local hydrogen. We conducted this in two steps: first, the affiliation of windmills to wind parks and second, the spatial evaluation whether sufficient hydrogen could be produced using adjacent wind power.

*Wind park affiliation*

Since the risk of plant failures is high for single windmills, only windmills which are part of a wind park were considered suitable (high availability). We affiliated wind parks using a kernel density estimation and empirically determined a 0.7 kernel density raster value as a threshold for wind park affiliation. Neighboring cells with a raster value larger than 0.7 where aggregated and transferred to vector polygons

**Table 3 – Diesel consumption of a 2-car Lint41 (BR 648) with 120 seats and a net mass of 68t.**

| Passenger utilization (seats occupied) | Diesel consumption [l/km] |
|---|---|
| No passengers | 0.58 |
| 28% | 0.61 |
| 100% | 0.66 |

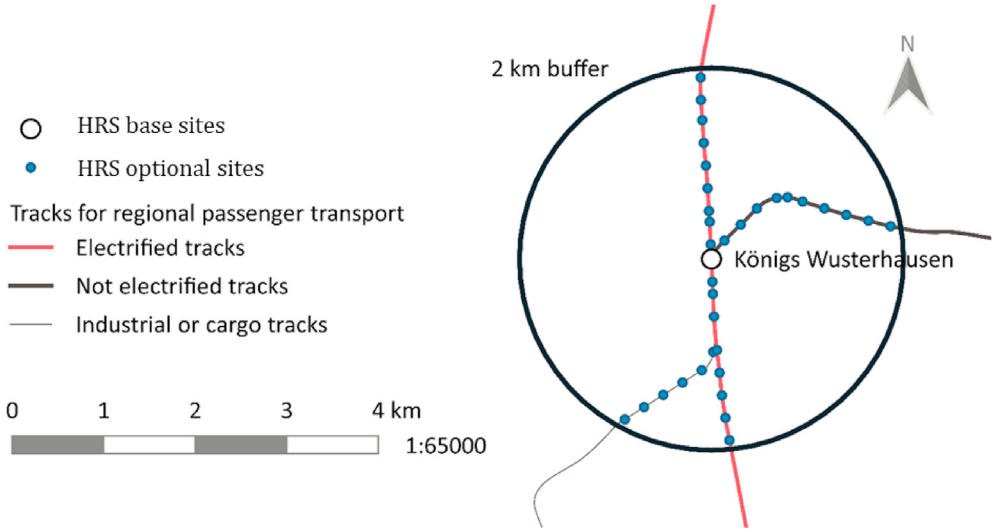


**Fig. 3 – Allocation of potential HRS sites using 2 km buffer.**

representing wind parks. For each affiliated wind park, we aggregated the rated capacity of the specific windmills. A detailed evaluation of the kernel density estimation can be found in Appendix A.

*Wind power production sufficiency analysis*

We tested wind park sufficiency by assessing whether a wind parks power output can provide sufficient hydrogen throughout the year and therefore ensure uninterrupted FCEMU-operation. We performed this test for several consumption loads (250–1500 kg H2/d) using modeled wind park load curves [68] based on MERRA2-reanalysis data [69] for the years 2014–2016.

We selected wind parks (from the data set produced prior) with varying locations, rated capacities, hub heights and turbine types. For each wind park, we calculated the percentage of days where production doldrums would lead to an insufficient hydrogen provision (percentage doldrums coverage - PDC). In order to calculate the PDC, we simulated hydrogen storage fill levels (as percentages) assuming storage capacities of three-, five-, seven- and ten-day storages (i.e., a three-day storage means, that hydrogen demand for three days can be stored), with:

$$level_{k,i} = \begin{cases} level_{k,i-1} + P_{H2} - H2_d, \; level_{k,i-1} + P_{H2} - H2_d < H2_d \times k \\ H2_d \times k, \; else \end{cases} \tag{6}$$

where $level_{k,i}$ is the level of the hydrogen storage in percent for size k (i.e. specific storage volume) at time i and $H2_d$ the daily hydrogen consumption in kg/d and $P_{H2}$ the possible daily hydrogen production (derived from the wind park output) in kg/d. The level demotes the percentage storage level of the exploitable tank volume, meaning that the minimum level in the storage tank at which hydrogen can be delivered equals to zero in the simulation. The initial load ($level_{k,i=0}$) is assumed to be fifty percent of the maximum load, calculated as:

$$level_{k,i=0} = H2_d \times k \times 0.5 \tag{7}$$

The PDC was then calculated with:

$$PDC = (D / N) \times 100\% \tag{8}$$

where N is the sum of days over the reference period and D is the number of days where hydrogen provision is insufficient (i.e. $level_{k,i} \leq H2_d$). A detailed PDC evaluation can be found in Appendix A.

### *Evaluation of suitable sites for on-site electrolysis*

In the final step of analysis, we identified potential sites for electrolysis and calculated the site-specific costs. The developed cost-model was evaluated with a sensitivity analysis in order to validate the model approach and to take possible future adaptions of costs into consideration.

*Spatial overlay for site-selection*

To determine potentially suitable sites for electrolysis, we buffered the HRS site layer (see Assessment of potential hydrogen consumption) and the wind park layer (see Assessment of suitable rail-adjacent wind power) with a buffer distance of 7 km (based on external expert assessment), rasterized the vector data sets (pixel size 250 m) and intersected the resulting arrays (see Fig. 4, upper half).

We then subtracted constraints (residential areas, protected areas, water bodies; for further information see Appendix B) from the resulting raster data set (see Fig. 4, lower half). The resulting layer forms the gridded area in Brandenburg generally suitable for off-grid hydrogen production. For each site we performed a nearest neighbor analysis determining the closest HRS site. The resulting hydrogen consumption was multiplied by 24 kW/kgH2 in order to get the minimum rated capacity (see section Wind power production sufficiency analysis). The nearest wind park with the

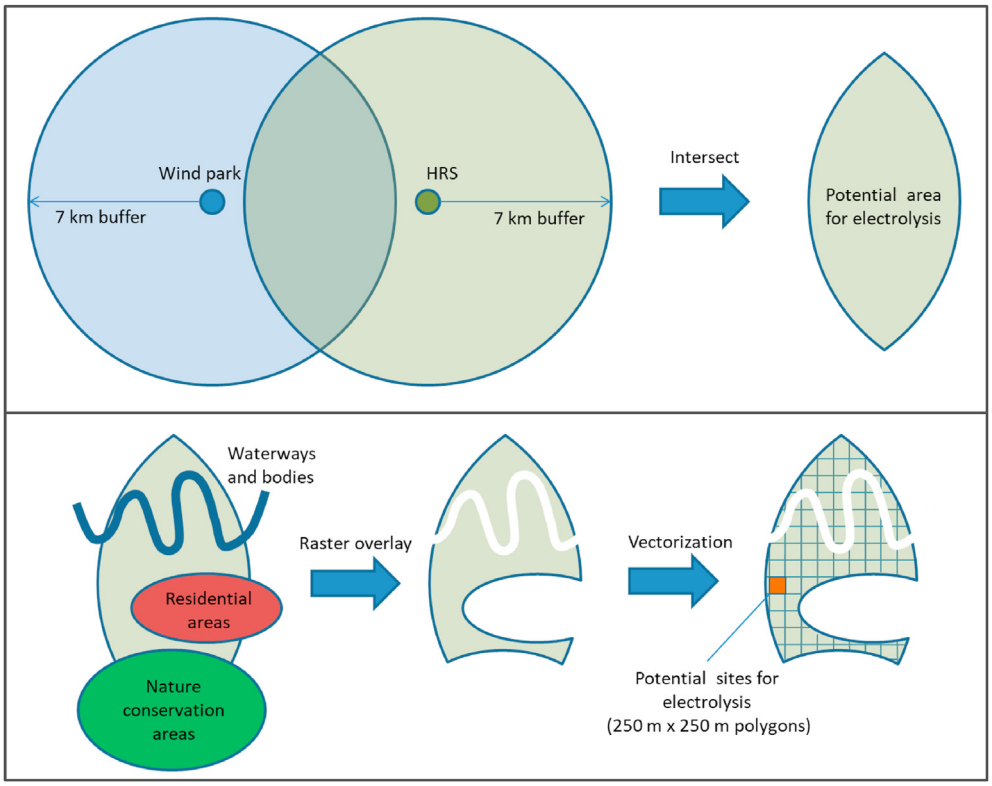


**Fig. 4 – Schematic geoprocessing for determining suitable areas for electrolysis plants.**

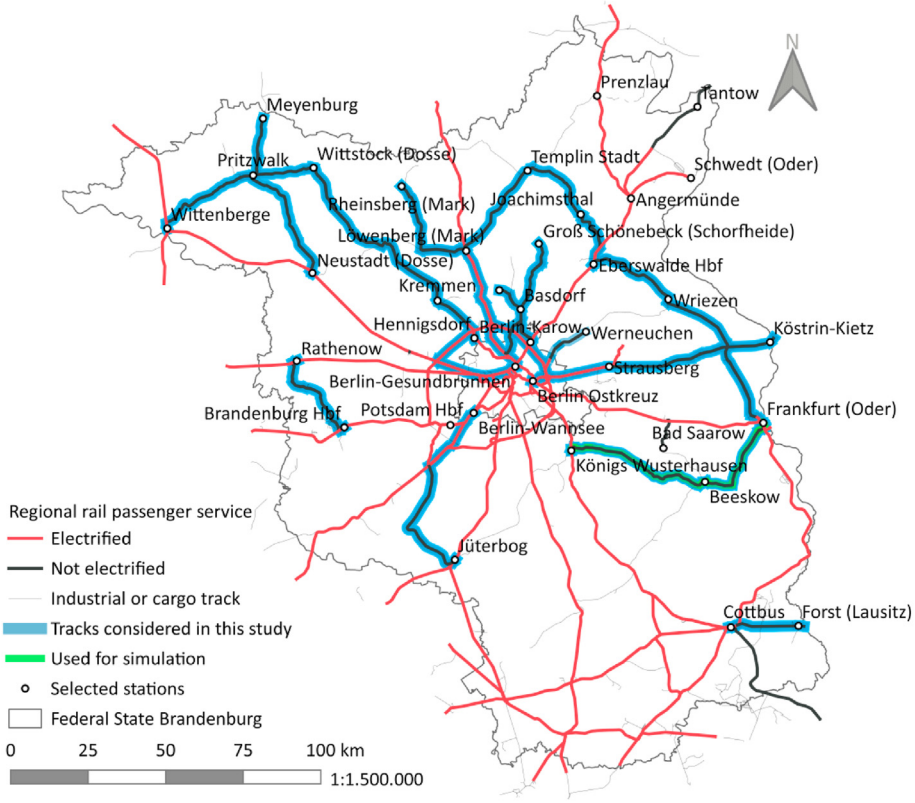


**Fig. 5 – Railroad tracks in the federal state of Brandenburg (comprising Berlin in the center).**

corresponding minimum capacity was then assigned. The specific rated capacity and the potential daily hydrogen consumption as well as the according linear distances were assigned as attributes to each polygon. As a proxy for the landscape type, we used the infrastructure density. For this we counted the intersections of a constructed line (forming the linear distance between each polygon and the specific wind park/HRS) to roads and waterways and assigned the number of intersections to each polygon.

*Hydrogen cost calculation*

We developed a cost model to calculate costs of hydrogen production and delivery. For this, we calculated capital expenditures (capex) and operational expenditures (opex) for each module shown in Fig. 2. Hydrogen costs were calculated in Euro per kilogram (€/kg)with a lower heating value for hydrogen Hi of 33.3 kWh/kg. For capex calculations we assumed a public funding rate of 45%, a 1.8% interest rate [70] and 2.75% of the capex for additional project costs [71] such as tender related expenditures, legal expenditures and land rents. Furthermore, we assumed an efficiency for electrolysis of 61.7% (i.e. 54 kWhelectr/kgH2) [11]. All parameters used for the cost calculation are shown in Tables 4–7.

Hydrogen cost $C_h$ was calculated with the sum of the annual capex (after funding) $C_a(f)$ where f is the funding rate, $O_a$ the annual opex, $I_a$ annual financing costs and $P_a$ the annual project costs, divided by the annual hydrogen consumption $H2_a$:

$$C_h = (C_a(f) + O_a + I_a + P_a) / H2_a \tag{9}$$

$C_a$ is computed with

$$C_a = \sum (C_k / l_k) \tag{10}$$

where $C_k$ is the capex of electrolyzer module k and $l_k$ its specific lifespan (see Table 4).

The capex for the compressors, storages and HRSs were computed with:

$$C_k = c_k \times H2_d \tag{11}$$

with $c_k$ as the module specific capex rate and $H2_d$ the average daily hydrogen consumption. Capex for pipelines and electric transmission cables were computed as follows, with

$$Ck = (c^k_{min} + ((c^k_{max} - c^k_{min}) / I_{kmax}) \times I_k) \times D_k \times d \tag{12}$$

where $c^k_{min}$ is the specific minimum cost per meter and $c^k_{max}$ the maximum cost per meter, $D_k$ the specific length of the transmission and d a detour factor, redeeming nonlinear cable/pipeline routings. $I_k$is the number of intersections as described in section Spatial overlay for site-selection. Capex of electrolysis $C_{el}$ was computed with:

$$C_{el} = C^{el}_{System} + (H2_d \times \eta \times H_i \times c_{stack} \times 365) / h_{el} \tag{13}$$

with $C^{el}_{System}$ being the fix capex system costs (e.g. for auxiliary plants such as heat exchanger, pumps, gas separators, etc.), η the efficiency of the PEM-electrolyzer (Table 7), $H_i$the lower heating value of hydrogen and $c_{stack}$ the specific capex investment rate in €/kW. This term is divided by $h_{el}$ which corresponds to 3500 annual full load hours.

The annual opex was computed as follows

$$O_a = \sum (C_k \times o_k) \tag{14}$$

where $o_k$ is the specific opex rate for module k. The only exception forms the opex calculation for the windmills $O_w$, which was computed as

$$O_w = H2_a \times \eta \times o_W \times H_i \tag{15}$$

with $o_W$ as the specific operating cost per kWh (€/kWh). Annual financing costs $I_a$ and yearly project costs $P_a$ were calculated with:

$$I_a = \sum (C_k) \times i \times f \tag{16}$$

$$P_a = C_a \times p \tag{17}$$

with i as the interest rate and p as the project cost rate.

### Sensitivity analysis

In order to test the sensitivity of the cost model and to determine which parameters influence the hydrogen production costs the most, we conducted a sensitivity analysis on capex, opex, wind power opex, PEM-stack costs, annual operating hours of the electrolyzer and efficiencies for the electrolyzer. With these parameters, we emphasized the sensitivity analysis on the costs of electrolysis. Therefore, we tested each parameter on how they influence the hydrogen costs by gradually changing the input parameters.

## Results

In the following sections we present the results of the performed analysis. Supplemental information in Appendix A might add to a better understanding of the presented results.

**Table 4 – Lifespans of plant modules.**

| Plant module | Lifespan l | Unit | Reference |
|---|---|---|---|
| Windmills | 20 | [a] | [21] |
| Electric transmission line | 20 | [a] | Own estimate |
| Electrolyzer stacks | 15 | [a] | Compare Appendix A Section: Stack Cost Parameters [24,29,72,73] |
| Electrolyzer system | 25 | [a] | [29] |
| Compressor | 15 | [a] | [58] |
| Hydrogen storage | 30 | [a] | [58] |
| HRS | 20 | [a] | [74] |
| Pipeline | 40 | [a] | [10] |

**Table 5 – Capex and Opex cost parameters.**

| Plant module | | Symbol | Value | Unit | Reference |
|---|---|---|---|---|---|
| Capex electrolyzer | Stack rate | $c_{stack}$ | 1000 | €/kW | [34] |
| | System | $C^{el}_{system}$ | 2,000,000 | € | |
| Capex compressor | | $c_k$ | 5000 | €/kg H2 | [43] |
| Capex hydrogen storage | | $c_k$ | 2935 | €/kg H2 | [34] |
| Capex HRS [47] | | $c_k$ | 5000 | €/kg H2 | [43] |
| Capex | Min | $c^k_{min}$ | 100 | €/m | Own estimate based on [10,49] |
| Electric transmission line | Max | $c^k_{max}$ | 500 | €/m | |
| Capex Pipeline | Min | $c^k_{min}$ | 350 | €/m | [10] |
| | Max | $c^k_{max}$ | 1500 | €/m | |
| Opex Windmills | | $o_W$ | 0.0285 | €/kWh | [21] |
| Opex elc. trans. line | | $o_k$ | 2.5 | %/a of spec. capex | Own estimate based on [46,49] |
| Opex electrolyzer | | $o_k$ | 3.5 | %/a of spec. capex | Own estimate based on [34,46,48,75] |
| Opex compressor | | $o_k$ | 4 | %/a of spec. capex | [58] |
| Opex hydrogen storage | | $o_k$ | 2 | %/a of spec. capex | [58] |
| Opex pipeline | | $o_k$ | 4 | %/a of spec. capex | [52] |
| Opex HRS | | $o_k$ | 5 | %/a of spec. capex | Own estimate based on [43,47,58,76] |

**Table 6 – Consecutive cost parameters.**

| Cost | Symbol | Value | Unit | Reference |
|---|---|---|---|---|
| Public funding rate | f | 45 | % of annual capex | [77] |
| Interest rate | i | 1.80 | %/a of overall capex | [70] |
| Additional project costs | p | 2.75 | %/a of annual capex | Own estimate derived from [71,78,79] |
| Detour factor | d | 1.2 | | Own estimate |

**Table 7 – Electrolyzer properties [11,13,43].**

| Name | Symbol | Value | Unit | Reference |
|---|---|---|---|---|
| Electrolysis efficiency | $\eta$ | 61.7 | % | [11] |
| Annual full load hours electrolyzer | $h_{el}$ | 3500 | h/a | Own estimate derived from [25,80] |

### *Assessment of potential hydrogen consumption*

In this section we present the results of the assessment of potential hydrogen consumption in the study area derived from the geospatial infrastructure data and operational data.

*Quantification of current train operating performance*

In the study region, 2470 km of railway tracks are used for passenger-rail-service of which 732 km are not electrified (Fig. 5). On 1.211 km of the railway tracks DMUs are in operation. There are eight rail concession networks where DMUs are operated. Within these eight networks, there are 21 DMU-operated railway lines which sum up to 12.2 million train-km yearly. In six of these networks, on 14 lines within, FCEMU-operation is generally feasible according to the assumptions made in Section Quantification of current train operating performance. These lines sum up to 867 km in length (648 km non-electrified) and 10.1 million train-km/a (of which 2.5 million are performed under catenary). The currently used DMU types are shown in Table 2 in section Quantification of current train operating performanc. In the following sections, we solely consider the FCEMU-suited railway lines, referring to them only as railway lines.

*Current diesel and potential hydrogen consumption*

According to the steps described in Section Quantification of current train operating performance we estimated an annual diesel demand of 9.5 million liters (i.e. 8029 tons) for all considered networks. Average diesel demand per kilometer is 0.783 l/km. The diesel demand per kilometer of the analyzed networks varies from 0.29 to 1.08 l/km. This is mainly due to the varying unladen masses of the DMU and the difference in double-heading. Hydrogen demands were calculated as potentially achievable demands assuming that the complete train operation on a line is switched to FCEMU. In the following we refer to it as hydrogen demand. The annual hydrogen demand accounts to overall 2198 tons. The highest demand per rail line is 540 t/a (RE6) and the lowest 6.4 t/a (RB74). An overview of the diesel and hydrogen demands by network is shown in Table 8. For better comparison, demands are given in GJ.

### *Assessment of suitable rail-adjacent wind power*

In the following section we assess if the currently available wind mills in the study area are capable of providing various amounts of hydrogen.

**Table 8 – Annual diesel and hydrogen demands of DMU/FCEMU grouped by tendered railway networks.**

| Network | Mill. train km/a | Diesel demand [GJ/a][a] | H2 demand [GJ/a][b] | Factor Diesel/H2[c] | Unladen mass of DMU [t] |
|---|---|---|---|---|---|
| Ostbrandenburg | 4.751 | 158,428 | 122,003 | 1,30 | 40–96.5 |
| Prignitz | 0.295 | 3750 | 6326 | 0,59 | 32 |
| NW-Brandenburg | 2.579 | 95,038 | 76,740 | 1,24 | 68 |
| Heidekrautbahn | 0.940 | 43,625 | 24,936 | 1,75 | 96.5 |
| Stadtbahn II | 1.250 | 35,685 | 26,781 | 1,33 | 73.3 |
| Spree-Neiße | 0.323 | 8707 | 6930 | 1,25 | 69 |

[a] With 0.84 kg/l and 43 GJ/t.
[b] With 120 MJ/t.
[c] The factor range mirrors the high variety of train masses of the incumbent DMU vehicles in operation today on the lines.

*Quantification of current windmill stock*

As of December 2018, there are 3772 operational windmills in the study region with an aggregated rated capacity of 6934 MW. On average, the plants have a rated capacity of 1.84 MW (median = 2.0; standard deviation = 0.776). Fig. 6a shows the distribution of the plant age for the reference year 2019, showing that only since EEG-compensation is available (year 2000), windmills had been erected on a broader scale in the upcoming years. Fig. 6b shows the trend to larger turbines over time due to advancing technology [71].

Fig. 6c shows the wind power capacity becoming ineligible to receive EEG-compensation. In 2020, 165 windmills with a rated capacity of 240 MW will become ineligible. Annually about 365 MW will become ineligible on average. Until 2030, 4100 MW of installed wind power capacity will cease to receive EEG feed-in compensation. For the complete windmill stock,

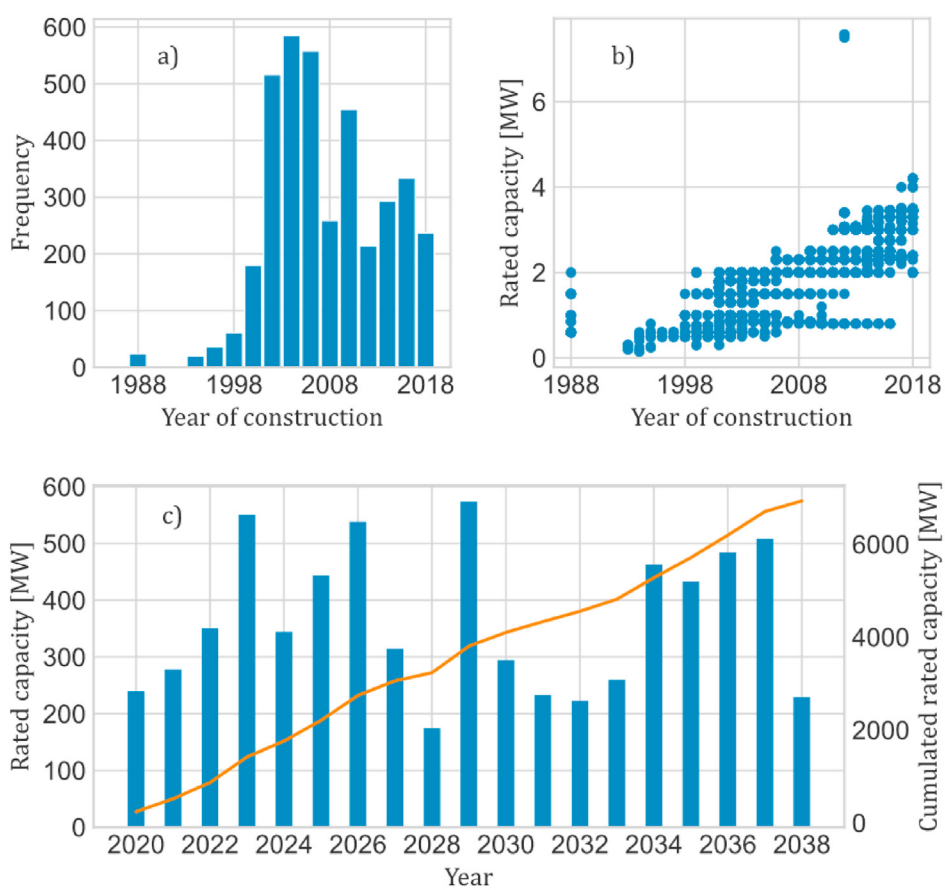


**Fig. 6 – Windmills standing stock: a) Year of construction b) Capacity-age-curve. Data available until 2018, c) Plants becoming ineligible to receive EEG-compensation.**

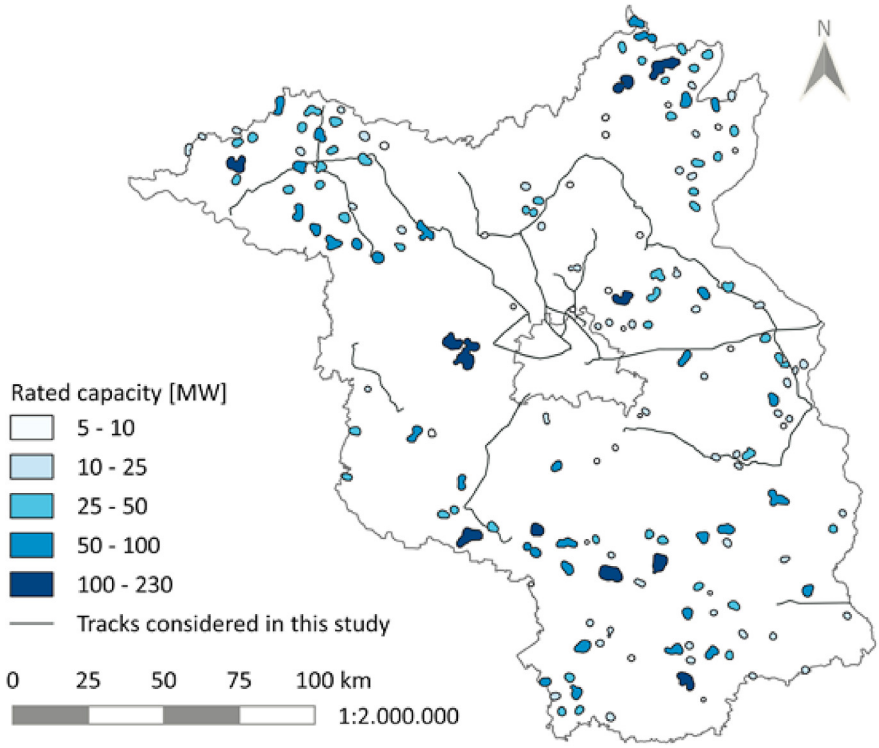


**Fig. 7 – Affiliated wind parks.**

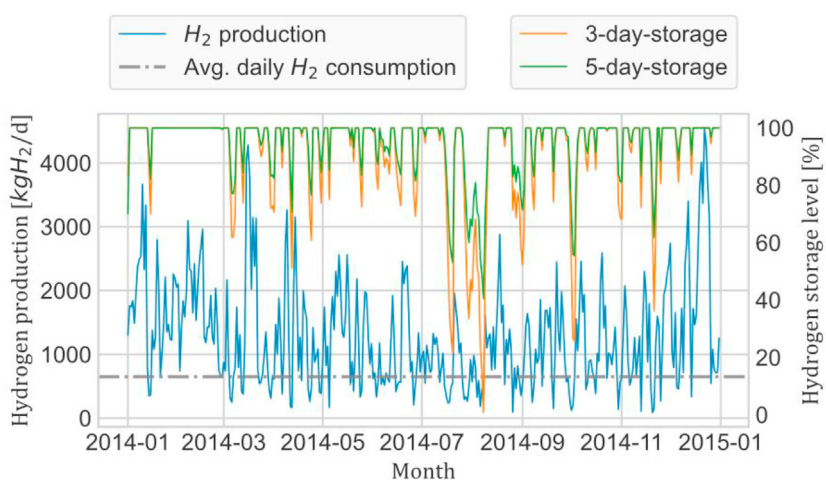


**Fig. 8 – Hydrogen production and simulated storage levels for a wind park at Frankfurt (Oder), for the year 2016. Assumed hydrogen consumption: 650 kg/d (grey dotted line).**

we affiliated 214 wind parks reaching an overall rated capacity of 6873 MW (Fig. 7).

*Wind power production sufficiency analysis*

The PDC was computed exemplarily for 12 wind parks with diverging characteristics (see Appendix A). A PDC of 99% means that on up to 11 days over the three reference years (one percent of 1095 days) the energy produced with those wind parks would not have provided enough hydrogen for FCEMU-operation. Thus, an external hydrogen delivery would be necessary. An example is shown in Fig. 8: With a 10.5 MW wind park and a 5-day storage capacity, a hydrogen consumption of 650 kg/d can be covered at all times during 2014 (which translates to a PDC of 100%).

From the empirical assessment of the 12 wind parks, we derived a threshold value on how much capacity is needed to provide a certain amount of daily hydrogen of 24 kW rated wind power capacity per kilogram hydrogen a day (assuming a 5-day storage). For a train line with a hydrogen consumption of 250 kg/d this corresponds to a necessary rated wind power capacity of 6000 kW. It should be stated, that this is an empirical value, which can deviate locally for various reasons. Also, it should be noted that the threshold of 24 kW/kg is derived from a PDC of 100% for all tested wind parks meaning this value ensures that there is a year-round sufficient hydrogen provision, guaranteeing an operation without additional hydrogen delivery.

### *Evaluation of suitable sites for on-site electrolysis*

In this section we present the results of the cost calculation and the results of the applied cost-model onto the study region.

#### *Site selection and cost calculation*

The parameter with the largest effect on the hydrogen costs is the daily hydrogen demand. Fig. 9 shows the relation between the two parameters for a representative model plant with a 3-km pipeline and a 1-km transmission cable. The diagram shows that with increasing consumptions, costs decrease non-linearly, with the costs converging upon a threshold defined by other cost parameters.

Six euros per kilogram of hydrogen is widely considered as a threshold for profitable operation (see Irena (2018) [81] and section Discussion for a brief discussion on hydrogen prices). Hydrogen costs of 6 €/kg and below can be achieved with a hydrogen demand of at least 1200 kg/d at favorable locations (pipeline 500 m, 0 intersections; transmission cable 500 m, 0 intersections). On sites which require longer pipelines and/or transmission cables, costs below six euros are unlikely. The lower the hydrogen demand, the stronger its effect on hydrogen production costs, and vice versa. The effect of the distance parameters (pipeline length, transmission cable length and the landscape type represented by the infrastructure density) on the production costs are shown in Fig. 10ab.

Current PEM stack costs and efficiency are shown in Fig. 10c (base case scenario). PEM stack costs and system costs are expected to decrease until 2030. In the scientific literature it's canonical that major price decreases for PEM stacks can be

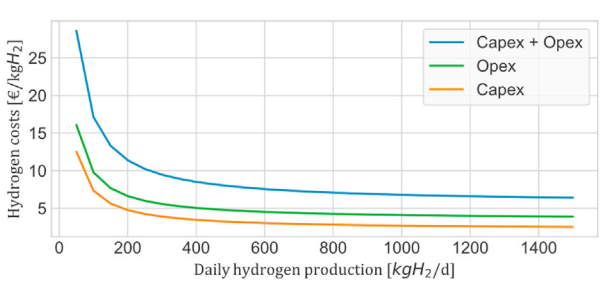


**Fig. 9 – Cost-production ratio for a model plant (pipeline: 3 km, 3 intersections; transmission cable: 3 km, 3 intersections).**

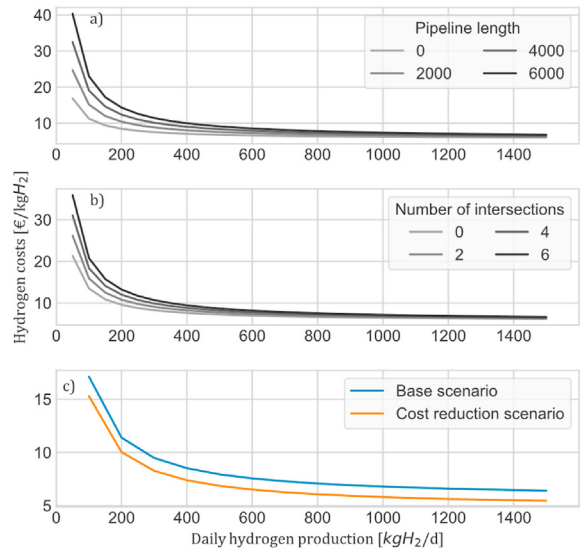


**Fig. 10 – a) Effect of pipeline length on hydrogen production costs; b): Effect of pipeline intersections on hydrogen production costs; c): Hydrogen production costs with base scenario costs and cost reduction (capex stack rate reduction = 50%, capex electrolysis system reduction = 25%, PEM stack efficiency increase = 11.5%. Each with pipeline 3000 m, 3 intersections, transmission cable 3000 m, 3 intersections.**

expected within the next decade. In Brynolf et al. (2017) [73] (review on cost reduction scenarios) it is stated that various sources predict price changes from 2400 €/kW in 2015 down to 800 €/kW in 2030. In Smolinka et al. (2018) [13], a study of expert interviews, a price reduction from 7000 to 4000 €/Nm$^3$/h is predicted. Recently Glenk & Reichelstein (2017) [27] fitted an exponential cost decrease curve over cost estimates from manufacturers and journals, reports and news. They expect a 4.77 +- 1.88% decline per year in PEM costs until 2030. Agnolucci et al. (2013) [53] used a spatial-economic approach using a capex cost model in combination with a spatial demand model and projected a green hydrogen price decrease of approx. 66%. Further studies such as Bertuccioli et al. (2014) [75] and Schiebahn et al. (2015) [25] back up the stated predictions. As PEM-stack-prices are expected to decrease, PEM efficiencies are likely to increase between 1% (Smolinka et al., 2018 [13]) and 23% (Götz et al., 2016 [11]). until 2030 depending on various aspects. If we put the expected efficiencies into perspective to our efficiency assumption, efficiencies might increase between 0.8% and 11.5%. Fig. 10c (cost reduction scenario) shows the calculated hydrogen costs assuming a stack price decrease of 50% and an electrolysis efficiency increase of 11.5% and a system capex decrease of 25%.

The cost model was applied on in total 17,869 potential sites for electrolysis, which equals to an area of 1117 km$^2$. The cost model applied on these sites show, that the lowest costs for hydrogen provision achievable is 6.40 €/kg. Fig. 11 shows areas with their corresponding production costs.

Table 9 shows the potential traffic and hydrogen consumption for each railway line and the corresponding

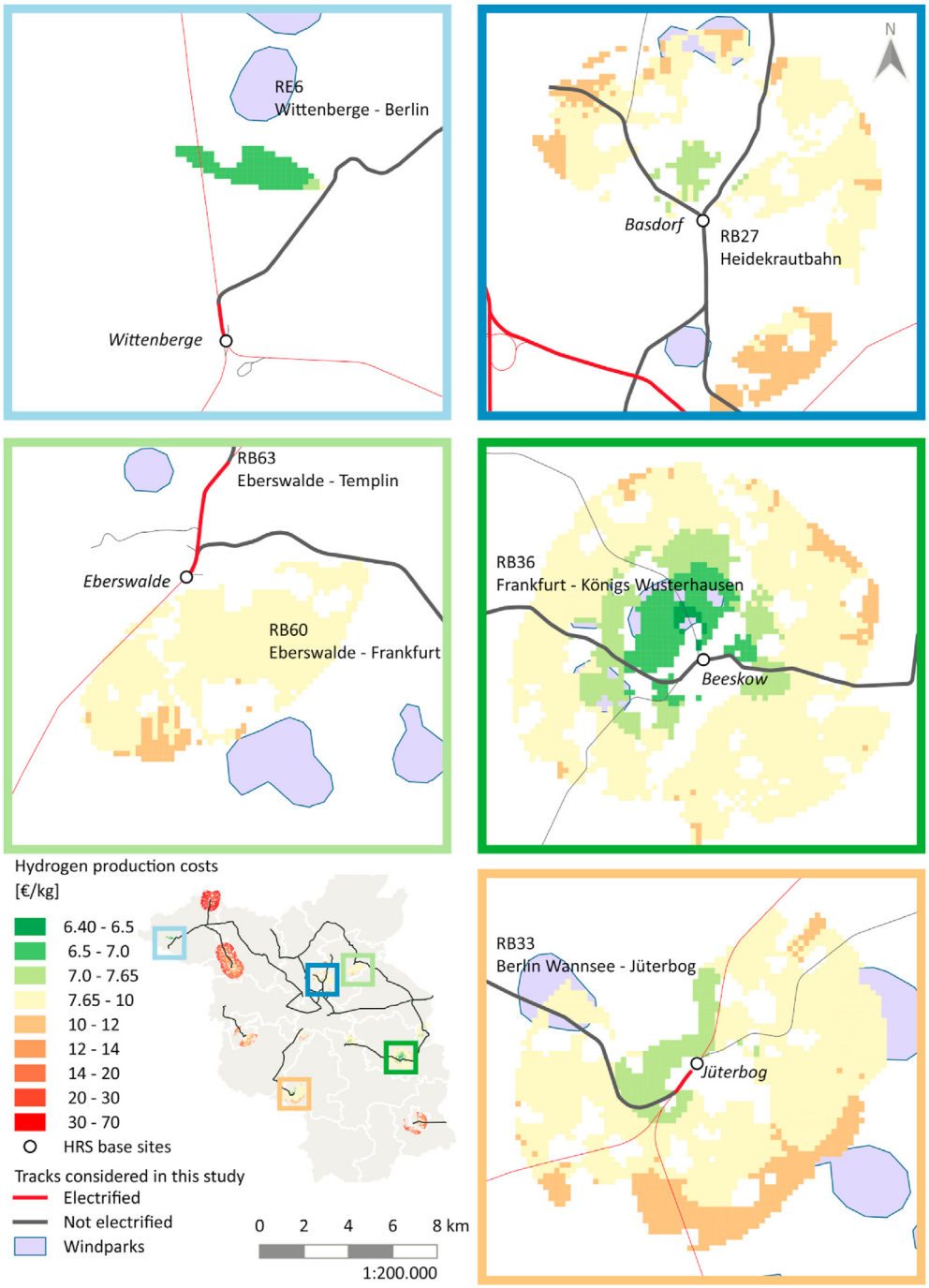


**Fig. 11 – Site-specific hydrogen production costs.**

minimal achievable hydrogen costs (i.e. the specific hydrogen costs of the most favorable EL-location).

*Sensitivity analysis*

In this section the results for the sensitivity analysis are shown for several parameters. Each parameter is exemplarily shown for two hydrogen consumption levels (500 kg/d and 1000 kg/d) with an assumption of a 3-km pipeline and a 3-km transmission cable, both with three intersections. Fig. 12ab shows the diagrams for the sensitivity analysis for the summed capex and opex and the windmill opex. The diagram shows, that both overall capex and overall opex have a linear influence on the hydrogen costs. The overall capex has a stronger effect on the hydrogen costs, because opex is calculated as an annual percentage of capex, meaning a decrease in capex leads to a decrease in opex, too.

The BWE predicts, that purchase prices for wind power between 0.0285 and 0.036 €/kWh are necessary to make the operation of aged windmills profitable. In the cost model we assumed 0.0285 €/kWh as the opex for wind power. This

**Table 9 – Railway lines with hydrogen demand and minimal hydrogen production costs.**

| Railway line | HRS site | Mill. train-km/a | Hydrogen demand [t/a] | Min. achievable H2 costs [€/kg][a] |
|---|---|---|---|---|
| RB27 Heidekrautbahn | Basdorf | 0.94 | 207.8 | 7.27 |
| RB33 Wannsee – Jüterbog | Jüterbog | 0.80 | 142.4 | 7.11 |
| RB63 Eberswalde – Templin | Eberswalde | 0.36 | 64.0 | 7.72 |
| RB60 Frankfurt - Eberswalde | Frankfurt | 0.70 | 125.5 | 6.84 |
| RB36 Frankfurt –K.Wusterh | Beeskow | 1.13 | 201.1 | 6.40 |
| RE6 Berlin– Wittenberge | Wittenberge | 2.34 | 597.1 | 6.64 |
| RB26 Berlin - Kostrzyn | N/A | 1.06 | 307.4 | N/A |
| RB46 Cottbus - Forst | Cottbus | 0.32 | 57.8 | 10.49 |
| RB12 Berlin - Templin | N/A | 1.20 | 265.4 | N/A |
| RB51 Brandenburg - Rathenow | Brandenburg | 0.45 | 80.7 | 9.83 |
| RB54 Berlin – Rheinsberg | N/A | 0.30 | 53.3 | N/A |
| RB73 Pritzwalk – Neustadt | Neustadt | 0.21 | 37.9 | 9.51 |
| RB74 Pritzwalk - Meyenburg | Meyenburg | 0.083 | 14.8 | 18.58 |

[a] N/A at HRS site/H2 costs means, that no suitable electrolysis sites could be found due to spatial restrictions.

might vary by location, turbine type and by the individual condition of a windmill. With an electricity price increase of 50% the hydrogen costs increase from 7.94 €/kg to 8.71 €/kg (Fig. 12a) respectively from 6.80€/kg to 7.57 €/kg (Fig. 12b).

Fig. 12cd and ef show the influence of the electrolysis parameters. By reducing PEM stack costs by 50%, hydrogen costs decrease to 7.30 €/kg (Fig. 12c). If the efficiency of the electrolysis is increased by 11.5% the hydrogen costs drops to 7.62 €/kg. For a consumption of 1000 kg/d (Fig. 12d) the costs drop to 6.15 €/kg with decreasing stack costs and to 6.47 €/kg with increasing electrolysis efficiency. The strong stack cost sensitivity shows that a price decrease of PEM stacks could enhance profitability considerably.

Unlike other parameters, the influence of the annual electrolyzer operating hours on the hydrogen costs is not linear. Operating hours have a strong effect with a decrease and a weaker effect with an increase. This shows that an economic operation of an electrolyzer is strongly related to its utilization profile. The higher the annual workload (i.e. full load hours), the lower the hydrogen production costs. This effect weakens when the workload converges upon the maximum annual operating hours of 8760 h. The relationship between the annual workload and the resulting hydrogen costs is further discussed in the recent literature [13,43].

## Discussion

The results of this study suggest that a FCEMU operation with hydrogen produced from local wind power is generally feasible in Berlin/Brandenburg. With the DMU-bound rail operation in the study region, an annual demand of 2199 tons of hydrogen could be generated. The installed wind power capacity could provide sufficient energy to cover the potential demand.

At favorable sites, a hydrogen demand of 1200 kg/d is necessary to achieve hydrogen production cost below 6 €/kg. Due to future decreases in electrolysis costs and increases in electrolysis efficiency the necessary consumption is likely to decline (265 kg/d at favorable sites, 2600 kg/d at the least favorable sites).

The main factor determining unit hydrogen production costs is the potential hydrogen consumption level. Other factors determining the costs of production are distances between wind park, electrolyzer site and the place of withdrawal (HRS) as well as the type of landscape in which pipelines and electric transmission cables need to be installed.

In Brandenburg, the lowest costs for hydrogen production are estimated around 6.40 €/kg. Assuming a decrease in PEM stack and system costs as well as an increase in efficiency for electrolyzers, onsite hydrogen from local wind power is likely to become cost-competitive in the near future.

Generally, our methodology showed that the study region bears great potential for the coupling of wind-energy and train operation given a great number of potential railway kilometers and the available wind power capacity as shown in Sections Quantification of current train operating performance and Quantification of current windmill stock. Nevertheless, we identified some limitations which will be discussed below.

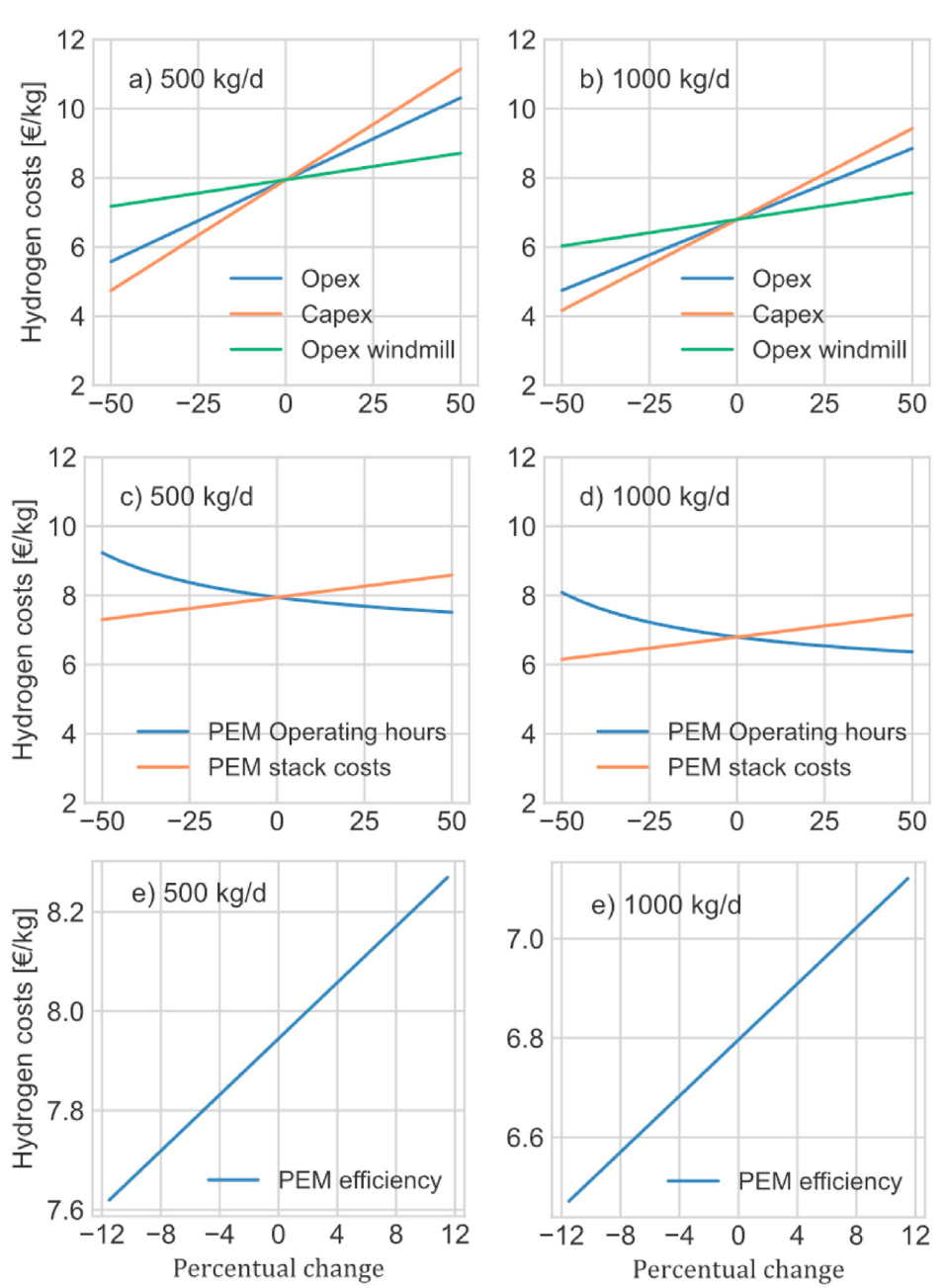


**Fig. 12 – Sensitivity diagrams. ab) Overall capex and opex; cd) Electrolysis cost parameters; ef) electrolysis efficiency.**

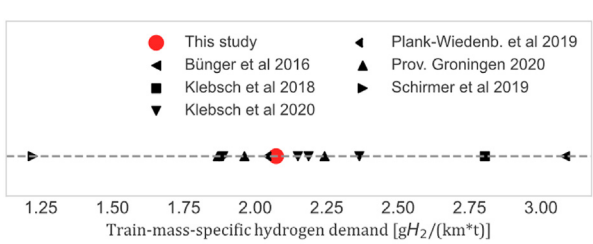


**Fig. 13 – Comparison of hydrogen consumption rates from literature proportionally to the unladen vehicle mass.**

In general, we considered most DMU-operated train lines in Brandenburg suited for the study. However, in practice many lines could also be operated with battery electric multiple units (BEMU) however there are restrictions to this operation regarding local renewable energy as discussed in section Introduction.

The potential hydrogen consumption is calculated with the simulated value of 0.17 kg H2/km referring to a generic two car FCEMU with 120 seats. The train size of the generic FCEMU (120 seats) is comparable to the sizes of actually operated Diesel cars (as presented in section Quantification of current train operating performance). In literature average hydrogen

demands are discussed in the range of 0.19 kg H2/km to 0.34 kg H2/km which are mostly based on the Alstom iLint train with 160 seats and respectively an unladen mass of 107 t. We considered a lighter 120 seat FCEMU as it is better suited to the sizes of Diesel cars (i.e. number of seats) currently operated in the investigated networks in Brandenburg (compare Table 2). Fig. 13 shows the hydrogen consumptions stated in the literature proportionally to the unladen vehicle mass.

The real, effective hydrogen demand varies depending on seasonality, route characteristics, vehicle specifications and energy management of the drivetrain. Thus, the assumed average hydrogen demand results in a certain inaccuracy, when discussing hydrogen demands on a train-size or line-specific level.

We determined HRS base sites with the underlying condition, that their position does not require changes in the current railway operation and timetables. Current locations of diesel refueling stations are often located where refueling requires additional service trips (which come with additional costs). Less conservative assumptions, for potential HRS sites could reduce hydrogen cost when placed in more favorable spatial conditions.

Windmills and wind parks considered in this study vary in age, location (average wind speed), hub height and turbine type. Whether after 20 years of plant operation a further operation is feasible, is mainly a question of the turbine type. Some models are very robust while some models might develop irreparable damages after years of operation. This however is not reflected in our method.

The wind-power sufficiency analysis is performed with model data from renewables. ninja [68] which are based on MERRA2-reanalysis data [69], meaning that the hourly production input for each windmill is not based on ground-truth data. Since measured outputs on plant scale were not available for varying locations and turbine types, the usage of the peer-reviewed and accuracy-tested model data provided a comparable and reproducible outcome.

The necessary rated capacity - derived from several wind park's PDC - is defined to provide sufficient energy at all times for all regions and turbines in Brandenburg. This was done because high reliability and low default rates are especially important in railway operation. Due to the conservative value the necessary rated capacity could be chosen more individually on a case-by-case level.

Longer length for pipelines (and transmission cables) might be fundable, but the longer the pipeline is designed, the more timely, costly and legally exhausting will be the approval procedure. The same accounts for the electrolysis sites. If the facility is located on a different site than the fueling station, additional legal approval schemes apply. Each legal admission comes with costly and timely procedures such as environmental impact assessments and technical approval assessments. These – besides the investment costs-can question the general feasibility of a project. Our method does acquire feasible locations for on-site electrolysis, however it fails to depict the complexity and uncertainty of legal procedures and such, due to the many stakeholders involved (property owners, operators, legislative personnel, etc., this could not be implemented into a spatial, technical and economic model.

The hydrogen costs calculated in this study compare to other published costs. The literature proposing hydrogen production costs consider mostly individual road traffic [53] or general traffic on a regional to national scale [13,58]. However the estimated costs of e.g. 5,12€/kg [53], 5.99 €/kg [58] and even 10 €/kg [13] found in the literature are comparable with the results of the cost model developed in this work. For example, with an assumed consumption of 1600 kg/d the model developed in this work computes hydrogen production costs between 5.91 €/kg and 7.73 €/kg. Considering a lower hydrogen production of e.g. 600 kg/d costs between 6.35 €/kg and 11.19 €/kg are estimated.

It is expected, that exceed hydrogen or energy might be produced which could generate additional income and reduce hydrogen costs significantly. Production costs could additionally be lowered through an increased hydrogen consumption, which could be achieved by selling hydrogen to industrial consumers, feeding into the natural gas grid or by making the hydrogen available to other means of (public) transport such as bus services, municipal waste collection, ferries or to individual road traffic.

We assessed the cost of hydrogen production in this work. The costs for implementing FCEMU trains (e.g. investment costs for vehicles, adjustments in maintenance equipment and machinery, training expenses for maintenance staff and drivers) need to be further considered.

## Conclusions

Interlinking rail transport and wind power production as a means of sector-coupling could be a main driver for decarbonizing traffic and help balancing a potential volatile renewable energy system. Public (rail) transport as a stable consumer could function as an early adaptor in hydrogen fueled transport, enabling a better understanding of the technology and pave the way to a functioning and ubiquitous infrastructure for fossil free fuels and a deeply integrated transport-energy system.

This study demonstrated sector-coupling potential on a regional scale and it showed that the potential for integrating energy and transport via hydrogen is high in Germany.

In Brandenburg itself about 10.1 million train-km annually could be switched to FCEMU-operation. This relates to a subsidized diesel consumption of appr. 9.5 million liters. At favorable sites hydrogen prices of approx. 6.40 €/kg could be achieved. Making excess hydrogen available for other consumers, would benefit lower hydrogen prices.

Wherever the public transport is widely powered with diesel, opportunities open up for fundamental carbon reductions and market opportunities for a newly developing technology.

This study was conducted for regional railway transport in Berlin/Brandenburg. In future works, the analytical approach could be applied on further regions (federal states) and countries and for other modes of transport such as public busses, municipal vehicles, waste collection and such.

Although the hydrogen costs for Berlin/Brandenburg calculated in this study are not competitive yet, it should be stated that sector-coupling projects have the opportunity to

create strong technological and political pull-effects like prove of feasibility, creation of precedent legal cases and best-practice examples and they also add to scale effects. The network effects of early pilot-schemes play an important role in the early stage of market penetration and can lead to a leverage effect on the market, therefore should not only be judged by economic benchmarks.

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## Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

## Nomenclature

| | |
|---|---|
| $c_k$ | capex of module k |
| $o_k$ | opex of module k |
| $\eta$ | electrolysis efficiency, % |
| f | public funding rate, % of annual capex |
| i | interest rate, %/a of overall capex |
| p | project cost rate, %/a of annual capex |
| d | detour factor |
| $h_{el}$ | annual full load hours electrolyzer |
| $H_i$ | Lower heating value of hydrogen, 33.3 kWh/kg |

*Subscripts*

| | |
|---|---|
| stack | electrolyzer stack |
| el system | electrolyzer system |
| el | electrolysis |
| a | annual |
| d | daily |
| w | windmill |

*Abbreviations*

| | |
|---|---|
| AEL | alkaline electrolysis |
| BEMU | battery electric multiple unit |
| Capex | capital expenditures |
| DMU | diesel multiple unit |
| EEG | renewable energy sources act (Germ.: Erneuerbare Energien Gesetz) |
| EL | electrolysis |
| EMU | electric multiple unit |
| FCEMU | fuel-cell electric multiple unit |
| GIS | geographic information system |
| HRS | hydrogen refueling stations |
| Opex | operational expenditures |
| P2G | power-to-gas |
| PEM | polymer electrolyte membrane |
| PDC | percentage doldrums coverage |
| ROG | federal regional planning act (Germ.: Raumordnungsgesetz) |
| SMR | steam methane reforming |
| WEG | dedicated wind power areas (Germ.: Windeignungsgebiete) |

## Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2020.11.242.

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