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Economic Analysis of Sector Coupling Business Models: Application on Green Hydrogen Use Cases

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Abstract:

Sector coupling will play a key role in the future energy system to realise greenhouse gas emission reductions. A major factor will be green hydrogen based on renewable energies to defossilise consumption sectors. Related business models of power to gas are not yet implemented on the market. However, given the urgency of the change, this is essential.

This paper investigates hydrogen business models under current market conditions of high power prices, no existing market for green hydrogen and the given regulatory framework with no levies for green hydrogen production in the German market. For this purpose, an open-source business model evaluation tool for sector coupling, which enables a simple and generic evaluation of sector coupling business models including production and possible transportation infrastructure, is developed and applied. Furthermore, the impact of changes of the input parameters like power prices and the influence of regulatory changes on profitability are assessed.

The results show that X-to-power business cases can be already profitable due to high power prices on the wholesale market. However, power-to-X business models like hydrogen production still have negative net present values and the net present value is worsened when infrastructure for hydrogen transportation is considered. Key parameters for the negative result are investment costs and low hydrogen prices. Nevertheless, it must be considered that higher hydrogen prices have a negative impact on the X-to-power business model. To allow for profitable business cases, the market conditions need to be adjusted to ensure sufficiently high prices for green hydrogen. Furthermore, subsidies on investment or operational and maintenance costs can support the integration of power-to-X into the market. Transportation infrastructure has a significant impact on profitability. Given these facts, it is necessary to create the required framework conditions to ensure the realisation of sector coupling.

Keywords: Sector coupling, Renewable energy, Hydrogen, Business model, Open source, Evaluation tool

1. Introduction

To be in line with the Paris Climate Agreement and the goal of limiting the global temperature increase well below 1.5°C [1], the EU and Germany aim to reach climate neutrality by 2050 [2] and 2045 [3] respectively. The reduction of anthropogenic greenhouse gas emissions is of crucial importance for achieving the target [4]. Emissions can be saved comparatively easily through technological adjustments, efficiency gains or sufficiency in some sectors like power production of the economy. In other sectors like heating, the reduction of greenhouse gases is much more complex [5,6]. These challenges will require new links between different parts of the energy industry and sector coupling will be an important element of the energy transition [7]. Power-to-Gas as one element of sector coupling enables the transfer of climate-neutral, renewable energy (RE) from sources such as solar or wind energy to the consumption sectors through the use of electrolysis [8,9].

Studies on greenhouse gas neutrality often show that hydrogen plays a crucial role in defossilisation of many application areas [10]. In addition, hydrogen is a key element of the EU and German strategy to achieve climate neutrality [2,11,12]. Therefore, the demand for hydrogen is expected to rise strongly until the 2040s [13]. In addition to electrolysis as the core element of power-to-gas, storage technologies, hydrogen turbines, fuel cells or refractory applications such as methanisation will be used. Applications in the heat sector, process heat generation or industrial processes up to mobility are possible fields of use for hydrogen [8,14–16]. Most of the power-to-gas technologies have already been tested in pilot projects and can demonstrate sufficient technological maturity for operation on an industrial scale [17–20].

However, in addition to the technical feasibility, the economic aspects also must be considered. In the current market environment, power-to-gas business models for hydrogen are not economically attractive [21–23]. Thus, sector coupling business models of power-to-gas are not established on the market [24]. Cost (e.g., technology investment, electricity purchase), additional taxes and levies and possible revenues from hydrogen production, have an impact on the profitability. In Germany, electricity tax, grid charges and levies for combined heat and power (KWKG) and renewable energies (EEG) must be considered. Recently, the EEG levy was higher than the wholesale electricity prices [25]. The levy was first reduced to 3.72 ct / kWh in January and entirely cancelled in July 2022 [26]. Furthermore, different studies show that power-to-gas can be economically feasible in the future and under certain market conditions [23,25,27].

Sector coupling business models are investigated recently but the analyses and methods are often not generically reusable. Examples are the analyses of battery storages in combination with power-to-heat operation on the frequency containment reserve market by Draheim et al. [28] or renewable hydrogen for rail transport by Guerra et al [29]. Balan et al. [30] derived a general approach for power-to-gas use cases for the Rumanian energy market but only for hydrogen and synthetic methane. Further studies like Agora Verkehrswende et al. [31] evaluate synthetic fuels in the transport and heating sector from the perspective of the energy system. Economic assessments like Akhtaria and Baneshib [32] also focus on the design of local energy system components but do not evaluate a specific business model. Investigations like Liu et al. [33] show a detailed approach of business model evaluation in the energy industry but lack of sector coupling considerations. Most of the studies use the net present value (NPV) for economic assessment.

The aim of this work is to analyse the potential of sector coupling technologies based on costs and revenues and to identify which economic, technical, and regulatory factors are important for the success of the business models. The focus lies on the currently high power prices and the regulatory influence on profitability. These aspects are to be considered sensitively to show the effects of changes of input parameters such as regulatory adjustments.

The further contribution of our work is the development of an open-source tool that covers the mentioned aspects, and which is not existing in research yet. The tool is generically structured and can be easily operated as an HTML application. This permits an easy application and transferability to different countries and market situations, which often has been difficult to realise in previous studies. Thus, the digital evaluation tool is an instrument that makes it possible to quickly assess the economic viability of a business model and can also be used in practice. In this context, the integrated sensitivity analysis allows the evaluation of uncertain developments when planning new business models.

The paper is structured in the following way. In section 2 the methodology of the tool is presented. This includes the general design of the tool, the mathematics, and the data. This includes the description of the three investigated business modes. The business models of hydrogen production with and without necessary infrastructure for transportation, and a business model to produce electricity based on hydrogen in the German market is selected. In section 3 the results of the tool are presented by providing the NPV of the business models and the impact of current changes on the power price development and regulatory framework (subsidies and levies) is shown. In section 5 the results are discussed, and section 6 concludes the work.

2. The business model evaluation tool

In this section, our model and the data basis of the analysis are presented. The term "business model" is used to describe qualitatively the abstracted logic by which a company aims to make profits [34]. A business case is the detailed plan including an analysis of financial aspects and the quantitative aspects of a business model [35]. Thus, a business case is an explicit realisation of a business model. Therefore, the open-source business model evaluation tool for sector coupling ($OBMET_{SC}$) enables the assessment of business models. In this paper, the NPV is used for the assessment, as a positive NPV is a key parameter for the realisation of a business model [35,36].

$OBMET_{SC}$ is available on git [37] and consists of a web application based on Python Flask and HTML for the user and several modules and functions in the python-based backend. The section includes an overview of the basic design of $OBMET_{SC}$ (Section 2.1), the general mathematics of the tool (Section 2.2), the basic data for the generic part and information about the data a user must define (Section 2.3), and the considered business models and used data for the final calculations (Section 2.4)

2.1 Approach of the business model evaluation tool

OBMET$_{SC}$ is structured into four blocks (figure 1). The basic concept is based on the modules: power supply, power-to-X (PtX), X-to-power (XtP) and additional infrastructure. Interfaces are implemented between the modules for the transfer of input and output values.

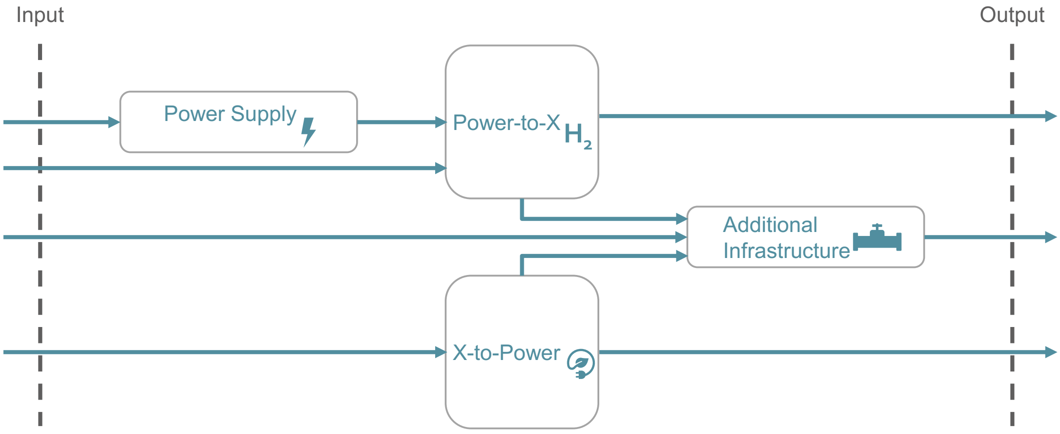

Figure 1: Modules of the open-source business model evaluation tool for sector coupling

The logic of OBMET$_{SC}$ is based on the distinction between business models that are based on PtX technology and XtP business models. Thus, it is possible to model single parts of the PtX-to-power chain as individual and as integrated business models. The structure and components of the individual PtX and XtP modules are therefore described below. Each module consists of different sub-modules, which implement individual calculation functions and are connected via input and output parameters as interfaces.

The first module of the assessment model is the power supply. Power supply is the starting point for all PtX business models. Electricity can be supplied either from the grid or directly from a RE source like wind or solar power. The electricity consumption of the PtX module is included in the calculation of the production profile and the economic feasibility of the entire plant.

The additional infrastructure module includes the possible design of a storage and transportation element. The design of the two elements is mainly dependent on the temporal structure of the PtX technology production profile. The dimensioning of the transportation element also depends on the distance to the consumption location. The two elements are necessary because fluctuating RE may require storage and, for example, in the case of hydrogen there are currently only a few cases where a connection between production and consumption already exists.

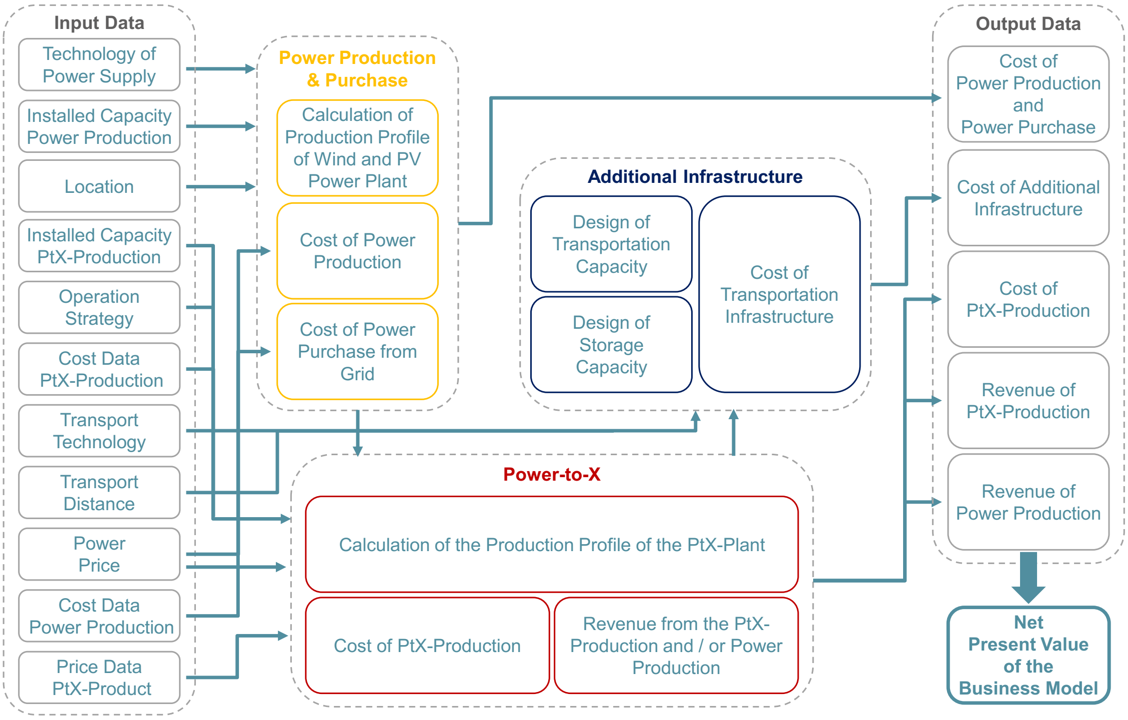

Figure 2: The Power-to-X Module of the open-source business model evaluation tool for sector coupling

The main input to the PtX module (figure 2) is the power supply. It builds the foundation for the calculation of the production profile, the production cost, and possible revenues and thus, the economic viability of the entire plant. Further inputs are cost parameters of the PtX technology, the operation strategy, and technological parameters such as capacity and efficiency. Furthermore, information about possible prices for the produced energy carrier (e.g., heat or hydrogen) is input of the Power-t-X module. Output of the module is the cost of power purchase, infrastructure, and production as well as revenues for the produced energy carriers. All the information is used to compute the NPV of the investigated business model.

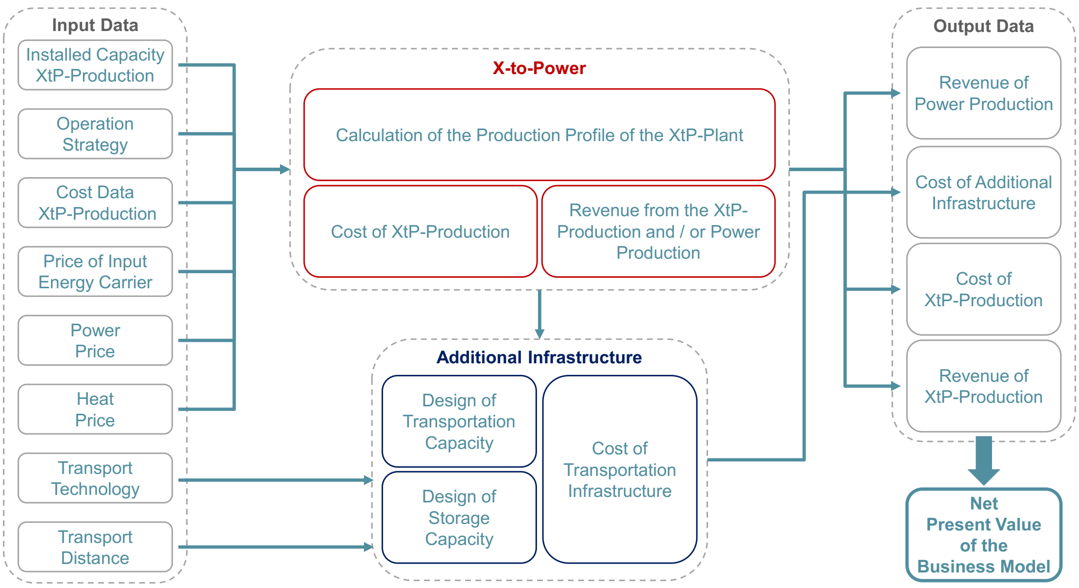

Figure 3: The X-to-Power Module of the open-source business model evaluation tool for sector coupling

The XtP module (figure 3) is necessary to model further conversion steps for energy carriers produced by PtX business models. Thus, the input is either the result of the PtX module or individually set by the user. Further input data refer to the used XtP technology (see technological parameters mentioned above) and the business model defined by the user. Results are also information about cost and revenue of the elements of the XtP module and the NPV.

2.2 Mathematics of the model

$OBMET_{SC}$ is based on various interrelationships and the resulting calculations. The calculations result in the revenue and cost structure of the business model and the NPV.

The power supply module is mainly designed to calculate the electricity production from RE plants and the associated costs. The module contains two elements, one for the load profile generation and the second for the cost of the RE plant. Business models that draw electricity from the grid do not require this module as power purchase costs are directly taken from the input data.

The production profile depends on the location, the installed capacity (P_{RE}) and the production technology (wind or photovoltaics (PV)). The temporal resolution of the model is hourly. Thus, for every hour the capacity factor ($Q_{RE,t}$) of the RE source is computed (E.1) by using the provided energy of the respective hour and a theoretical plant of 1 MW.

$$(E.1)\ Q_{RE,t} = \frac{Energy_{RE,t}}{Capactiy_{RE}}$$

Thus, the capacity factor ($Q_{RE,t}$) is a location-specific vector for the RE sources with a value for every hour of the year. The realised electricity production ($X_{Re,t}$) of a RE plant depends on the installed capacity ($P_{installed,RE}$) defined by the user. The electricity production profile of the plant under consideration is the result of multiplying the capacity factor with the installed capacity (E.2). The model also allows a combination of different RE sources in a hybrid system (e.g., wind and PV).

$$(E.2)\ X_{RE,t} = Q_{RE,t} * \ P_{installed,RE}$$

The specific operating costs have two components, one for annual fixed costs depending on the installed capacity and the second on the produced power. The cost of the RE power ($C_{fixed,RE,a}$) is calculated based on the installed capacity as no variable costs for RE input energy is assumed. Thus, the investment costs ($CapEx_{RE}$), the specific fixed operating costs ($OpEx_{RE}$) and the lifetime (a) are relevant input parameters (E.3). In the case of an own RE plant, the second part is assumed to be zero.

$$(E.3)\ C_{fixed,RE,a} = CaPex_{RE,a} * P_{installed,RE} + OpEx_{Re,a} * P_{installed,RE}$$

In the case of power supply by the wholesale market, this factor corresponds to the wholesale electricity price ($P_{WS,t,a}$) and additional fees (e.g., grid usage fees and taxes). In the case of power supply by the wholesale market, E.4 represents a cost factor. Furthermore, possible revenue by selling the power on the wholesale market is considered (E.4). In this way the module considers the opportunity that alternative ways of power supply are possible and selling power could be more economically viable than using the electricity for the PtX plant. The hourly net wholesale electricity price ($P_{WS,t,a}$) is taken into account and over the lifetime it is possible to assume a price development ($\mathrm{PriceChange_a}$) set by the user ($R_{RE,t,a}$).

$$(E.4)\ R_{RE,t,a} = X_{RE,t} * P_{WS,t,a} * \mathrm{PriceChange_a}$$

These values are the starting point for the calculations of the PtX module. It is possible to consider a combined power purchase via the grid and a RE power plant. This is important as the user defines the installed capacity of the components and the RE power plant might be too small or too big for the PtX plant.

The first step is the calculation of the hourly production profile of the PtX plant ($X_{t,PtX}$). In addition to plant-specific parameters such as the efficiency (η_{PtX}), information about the achievable revenue price of the PtX product and the production costs are necessary. The module allows two different operation modes: maximisation of the production PtX plant and optimisation of the revenues.

In the case of maximising production, the production profile depends on the availability of power. In addition to the installed capacities, the produced quantity depends on the efficiency of the PtX plant (E.5). In the case of a grid connection, the production profile is constant and equals the installed power multiplied by the efficiency (E.6).

$$(E.5)\ X_{PtX,t} = MIN\ (X_{RE,t} * \eta_{\mathrm{PtX}}, \mathrm{P_{installed,PtX}} * \eta_{\mathrm{PtX}})$$

$$(E.6)\ X_{PTX,t} = \ \mathrm{P_{installed,PtX}} * \eta_{\mathrm{PtX}}$$

In the second case, the production depends on the hourly costs and revenues. In this operation mode, production only takes place when marginal revenue is positive. When electricity prices are high, the electricity is either not purchased or power produced by the RE plant can be sold on the wholesale market. The PtX plant is operated when the sum of the variable costs (c_{var}) and the quotient of power costs (c_{power}) and efficiency (η_{PtX}) is smaller than the achievable revenues (R_{PtX}) of the product (E.7). The result of this condition is binary and is used to compute the production profile of the PtX plant ($X_{PtX,t}$).

$$(E.7)\ \frac{c_{power,t,a}}{\eta_{\mathrm{PtX}}} + C_{var,PtX,t,a} < R_{PtX,t,a}$$

Furthermore, in the case of RE plants for power supply, the consumption of RE ($\mathrm{consumption_{RE,t}}$) is computed (E.8). Based on this result, the consumption of power from the grid ($\mathrm{consumption_{WS,t}}$) is calculated (E.9) in case of an undersupply or the amount of sold power on the wholesale market ($\mathrm{power_{sold,t}}$) in case of an oversupply (E.10).

$$(E.8)\ \mathrm{consumption_{RE,t}} = MIN(\frac{X_{PtX,t}}{\eta_{\mathrm{PtX}}}, X_{RE,t})$$

$$(E.9)\ \mathrm{consumption_{WS,t}} = X_{PtX,t} - \ \mathrm{consumption_{RE,t}}$$

$$(E.10)\ \mathrm{power_{sold,t}} = X_{RE,t} - \ \mathrm{consumption_{RE,t}}$$

The calculation of the fixed cost in every period follows the same structure as in the case of the RE plant (E.11). The difference is that the cost of the power production by the RE power plant ($c_{Re,a}$) is considered separately.

$$(E.11)\ C_{fixed,PtX,a} = CapEx_{PtX,a} * P_{installed,PtX} + OpEx_{PtX,a} * P_{installed,PtX} + C_{RE,a}$$

The variable costs ($C_{var,PtX,t,a}$) result from the costs for the power purchase and other variable costs (E.12). At this part of the PtX module, the impact of cost due to regulatory requirements is considered. Taxes, levies, and charges on the power purchase either by the RE plant ($c_{Reg,RE}$) or on the wholesale market ($c_{Reg,WS}$) have an impact on the profitability. Costs like EEG or KWKG levy, grid usage charges or the electricity tax are part of the specific cost parameter.

$$(E.12)\ C_{var,PtX,t,a} = \mathrm{consumption}_{\mathrm{WS,t}} * \left(c_{power,t,a} + c_{Reg,WS}\right) + \mathrm{consumption}_{\mathrm{RE,t}} * c_{Reg,RE} + c_{other,var,t} * X_{PtX,t}$$

Furthermore, it is possible to consider the impact of subsidies on the business model. The user can investigate the impact either by setting subsidies direct on the fixed or the variable cost. In this case, the cost components will be reduced before calculating the numbers.

The total revenues ($R_{Total,t,a}$) of a PtX business model are generated by selling the produced PtX energy carrier and the not used surplus electricity from the RE plant (E.13).

$$(E.13)\ R_{Total,t,a} = R_{PtX,t,a} + R_{RE,t,a} = X_{PtX,t} * P_{PtX,t,a} * \mathrm{PriceChange_a} + X_{RE,t} * P_{WS,t,a} * \mathrm{PriceChange_a}$$

The NPV is formed from all costs and revenues, the lifetime, and the selected interest rate (i) by the user (E.14).

$$(E.14)\ NPV = \sum_{k=0}^{a}\sum_{l=0}^{t} R_{Total,t,a} * (1+i)^{-k}) - \sum_{k=0}^{a}\sum_{l=0}^{t} (C_{fixed,PtX,a} + C_{var,PtX,t,a}) * (1+i)^{-k})$$

The XtP module is designed similarly. In the same way as for PtX, the production of another energy carrier such as electricity or heat can also be realised either by maximising production or by maximising revenues. The chosen operation mode defines the capacity factor in every hour ($Q_{XtP,t}$). In addition, co-generation of different energy carriers is considered. For example, the use of waste heat in electricity production can be used as a further revenue stream to generate additional income.

The production profile (E.15) of the specific energy carrier ($X_{XtP,EC,t}$) is calculated by using the installed capacity (P_{XtP}) and efficiency ($\eta_{EC,XtP}$). The required amount of PtX energy ($X_{PtX,t}$) as input is calculated. by using the production profile and the efficiency (E.16).

$$(E.15)\ X_{XtP,EC,t} = P_{XtP} * \eta_{\mathrm{EC,XtP}}$$

$$(E.16)\ X_{PtX,t} = \frac{X_{XtP,EC,t}}{\eta_{\mathrm{XtP}}}$$

The cost and revenue calculations are structured as described above and are composed of fixed and variable costs. In the case of an integrated analysis, the variable price for the necessary amount of PtX energy carrier ($c_{PtX,t,a}$) is a result of the PtX module. In the case of an independent business model, the price is set by the user.

In contrast to PtX business models, the economic effects of regulatory requirements are only considered indirectly. In the case of an integrated analysis, they are part of the PtX module. In the case of an independent business model, it is assumed that the supply with a PtX based energy carrier, such as hydrogen, is realised via an independent infrastructure. Thus, costs for the supply are part of the costs set by the user. Possible subsidies of fixed and variable costs are also possible, set analogously by the user and applied directly to the cost parameters.

The revenues of XtP business models follow the logic in E.13. The component for produced electricity is the same but in the case of other carriers such as heat a specific price needs to be set by the user. The final calculation of the NPV follows the logic in E.14.

For the economic evaluation of business models, the transport and storage infrastructure can be considered as an additional element of the business model. For example, there is no publicly accessible network for green hydrogen and additional infrastructure may be necessary as part of a business model. For the business model assessment, it is assumed that no revenues can be generated through infrastructure. Thus, it just has an impact on the costs. The module consists of two elements. The first is for the infrastructure design and the second is for the calculation of the cost ($c_{infrastrucutre}$).

The options assumed for the transportation are a liquified gas trailer, gas trailer and pipeline. In addition to the production profile, assumptions about the transport distance, the maximum permissible pressure and the specific transport capacity of the individual technologies are necessary. For gas trailers and liquefied gas trailers, the number of necessary transporters is calculated. For pipeline design, the diameter is needed in addition to the distance for cost estimation.

For pipelines, the maximum output ($\dot{Q}_{max}$) is taken as input for dimensioning the diameter (E.17). For the dimensioning, the flow rate in MWh is converted into a mass flow (E.18) by means of using the energy density (ρ).

$$(E.17)\ \dot{Q}_{max} = MAX(X_{PtX,1}, \dots, X_{PtX,8760})$$

$$(E.18)\ \dot{m} = \dot{Q} * \rho$$

The diameter of the pipeline (d) is calculated by the volume flow ($\dot{V}$) and the velocity (v). Since hydrogen shows almost ideal gas behaviour up to a pressure of 100 bar, the ideal gas equation can be used to compute the volume flow (E.19) [38,39].

$$(E.19)\ d = \sqrt{\frac{4}{\pi} * \frac{\dot{m} * Rs * T}{v * p}}$$

In case of the transportation via trailer, the ratio of the amount of necessary daily transport routes (TR_{total}) and the capacity of a trailer ($cap_{trailer}$) defines the necessary number of trailers (E.20). Further input is the number of daily transport routes done by one trailer ($TR_{trailer}$, E.21). This factor depends on the transport distance (s), the loading and unloading time ($time_{loading}$), transportation speed (v_{trans}) and daily working time (WT). The necessary number of trailers ($number_{trailer}$) is the quotient of necessary daily transport routes and the number of daily transport routes done by one trailer.

$$(E.20)\ TR_{total} = \frac{\frac{\sum X_{PtX,t}}{365}}{Cap_{trailer}}$$

$$(E.21)\ TR_{trailer} = \frac{WT}{\frac{s}{v_{trans}} + time_{loading}}$$

In case of the transportation via trailer, a buffer storage is considered. The number of storages required (E.22) depends on the maximum output ($\dot{Q}_{max}$), the daily working time (WT), the necessary daily transport routes, and the storage capacity ($cap_{storage}$).

$$(E.22)\ Number_{storages} = \frac{\dot{Q}_{max} * \frac{WT}{TR_{total}}}{Cap_{storage}}$$

Specific investment and operational costs for gas trailers, liquified gas trailers, pipelines and storages are used in the calculation of the cost of the additional infrastructure. In addition, costs for compression are applied, which depend on the installed electrolysis capacity and the type of transport. The total cost consists of investment elements ($c_{infrastrucutre,invest}$, E.23) and operation elements ($c_{infrastrucutre,operation}$, E.24). In case existing infrastructure is used, the costs are input in the NPV calculation of the PtX module.

$$\begin{aligned}(E.23) C_{infrastructure,invest,a} \\ &= cost_{pipeline,diameter,a} * s + cost_{Trailer,type,a} * Number_{trailers,a} + cost_{sotrages,a} \\ &* Number_{storages} + cost_{compresion,transporttype,a} * P_{PtX}\end{aligned}$$

$$\begin{aligned}(E.24)\ C_{infrastructure,operation,t,a} \\ &= cost_{pieline,operation,t,a} * s + cost_{trailer,operation,t,a} * Number_{trailers,a} \\ &+ cost_{sotrages,operation,t,a} * Number_{storages} + cost_{compresion,var,t,a} * \dot{m}\end{aligned}$$

2.3 Data

In the next section, the data basis of the parameters used for the calculations of the four modules is presented. The input parameters are divided into four categories: database parameters, input parameters set by the user, opt-in parameters, which can be generated either by the user or from the database, and output parameters of other modules and functions. $OBMET_{SC}$ provides a broad basis of data for the calculation, which can be adapted to the specific case by the user. The approach allows the user to freely quantify revenues from the sale of the energy carrier or costs of the selected technology in the model. In contrast, energy industry parameters, such as the revenues or costs of electricity purchase, can be estimated based on historical market information.

Parameters set completely by the database are wind and solar power generation profiles. Site-specific production profiles for PV and wind plants are used for all federal states in Germany. The profiles were calculated using the online calculation tool Renewables.ninja which is based on MERRA-2 weather data [40–42].

The wholesale electricity prices are provided with the net exchange electricity prices of the day-ahead market of the EPEX SPOT exchange (table 1). The time series for the German market zone is based on the year 2021 [43,44]. Currently, the price for PtX energy sources cannot be determined based on a reference market. Thus, the provided information is based on existing references to existing submarkets or conventional substitutes. When considering hydrogen, a distinction was made between three different prices for green, blue and grey hydrogen [45]. This allows the consideration of different markets when modelling a PtX business model. Furthermore, prices for ammonia and methane are part of the database to provide the opportunity to model energy carriers based on hydrogen. The values can also be set by the user based on their own information. In the case of heat, the user must provide their own assumptions for the price.

Table 1: Cost parameters for energy carriers in the database of the $OBMET_{SC}$

Parameter	**Price [EUR / MWh]**	**Source**
Green hydrogen (mean 2021)	278.00	[46]
Grey hydrogen (mean 2021)	89.91	[47]
Blue hydrogen (mean 2021)	95.20	[48]
Ammonia (mean 2021)	73,57	[49]
Methane (mean 2021)	55.89	[50,51]
Bio methane (mean 2021)	75.00	[52]
Power (mean 2021)	96.85	[53]

Further data (table 2) provided by the database describes the basic technological (e.g., thermal, and electrical efficiency) and economic parameters of the sector coupling technologies. This data is either set by the user or taken from the database. The database includes various electrolysis technologies and the associated infrastructure, gas/hydrogen turbines for power and heat generation. In the absence of cost data for pure hydrogen power plants, data for conventional gas and steam power plants are used. In the case of conversion of existing power plants to hydrogen operation, the costs for operation with hydrogen are approximately estimated at 50 % of the installation costs. The data basis for the dimensioning of additional infrastructure is restricted to the transportation and storage of hydrogen. Data for hydrogen transportation via pipelines includes pressure, flow velocity and diameters [54–56]. Data for trailer transportation refers to transport pressure and the resulting transport capacity [57].

Table 2: Cost and technological parameters in the database of $OBMET_{SC}$

Technology	Investment cost	Operational cost [% of investment cost]	Efficiency	Sources
Polymer electrolyte membrane (PEM) electrolysis	1,610 [EUR / kw_{el}]	4	0.71	[58,59]
Alkaline water electrolysis (AEL) electrolysis	878 [EUR / kw_{el}]	4	0.68	[58,59]
Power-to-methane	2,275 [EUR / kw_{el}]	4	0.56	[58,59]
Power-to-ammonia	2,653 [EUR / kw_{el}]	4	0.45	[58,60]
Fuel cell	1,130 [EUR / kw_{el}]	4	0.28_{th}, 0.62_{el}	[58,61,62]
Combined cycle gas turbine	550 [EUR / kw_{el}]	4	0.27_{th}, 0.61_{el}	[63,64]
Wind turbine	1,200 [EUR / kw_{el}]	4	1	[42,58]
PV	650 [EUR / kw_{el}]	2.5	1	[42,58]
Compression until 100 bars	3,000 [EUR / kW_{Comp}]	75	0.046 [kW_{Comp}/kW_{El}]	[57]
Compression until 500 bars	3,500 [EUR / kW_{Comp}]	75	0.157 [kW_{Comp}/kW_{El}]	[57]
Regasification hydrogen	7,200 [EUR / kg h]	76	1	[57]
Gas trailer	150,000 [EUR / trailer]	75,000 [EUR / a]	1	[57]
Liquid gas trailer	650.000 [EUR / kW_{Comp}]	75,000 [EUR / a]	1	[57]
Pipeline DN 250	1,200,000 [EUR / km]	1,5	1	[58]
Pipeline DN 500	1,500,000 [EUR / km]	1,5	1	[58]
Pipeline DN 1100	2,800,000 [EUR / km]	1,5	1	[58]

Another aspect is the compressor to liquefy hydrogen for trailer transportation. A constant compression is assumed, which is only dependent on the throughput and thus, on the installed electrolysis power. This ratio is described with a factor from the literature, which expresses the compressor costs as a function of hydrogen production. For liquefied hydrogen, the dimensioning of a liquefaction plant depends only on the throughput as liquified hydrogen is incompressible. The specific cost data is selected from the literature and refers to the costs per liquefied unit of mass of hydrogen [57]. For business models with the output methane or for electricity and heat, it is assumed that the necessary transportation option already exists.

2.4 Business Cases

The presented $OBMET_{SC}$ will be applied and further presented by using three business models. Business models of the hydrogen value chain are applied. In the first case, the operation of electrolysis with electricity from own PV capacity is considered. The second case is an expansion of the first one and includes the integration of additional infrastructure into the business model. This allows the assessment of the impact of the infrastructure as in the current situation no hydrogen grid exists. In both cases, revenues from selling hydrogen or power are possible. The third business case is the consideration of a replacement of fossil gas turbines with hydrogen turbines. In this case, the revenues are generated via selling power and heat.

The input parameters of the business model assessment are based on the information from the integrated database presented in section 2.3. The further values to be set by the user are provided below.

The PEM electrolysis has an installed capacity of 10 MW_{el}. The PV plant is dimensioned for 20 MW_{el}. As PV is used the plant is located in Bavaria in southern Germany with higher solar radiation. The grid usage fees for industrial customers are 24 EUR / MWh_{el}. The hydrogen power plant has a capacity of 30 MW_{el}. The plants use the operation mode of maximising profits.

In all cases, a lifetime of 25 years and weighted average cost of capital (WACC) of 7 % is assumed. For revenues and consumption from electricity on the wholesale market, the 2019 time series is scaled to the 2021 mean and standard deviation to consider a more even price development over the year. Further electricity price components are the grid usage fees of 24 €/MWh for industrial customers in Bavaria [65]. In the case of considering additional infrastructure, it is assumed that a customer 1 km away is supplied at a price of 90 EUR / MWh_{H2}. The hydrogen power plant is supplied with blue hydrogen at the same cost of 90 EUR / MWh_{H2}. Possible revenues from selling heat are assumed to be 20 EUR / MWh.

3. Results

The business models of PtX show in both cases, the green hydrogen production with and without additional transportation infrastructure, a negative NPV. In contrast, power production with a hydrogen turbine has a positive NPV. Detailed results are discussed in the following sections.

3.1 Results of the business model assessment

The hydrogen production with PtX based on PV production is not economically viable under current market conditions. The NVP of hydrogen production is -5.0 million EUR and it drops to -9.6 million EUR when considering necessary transportation infrastructure.

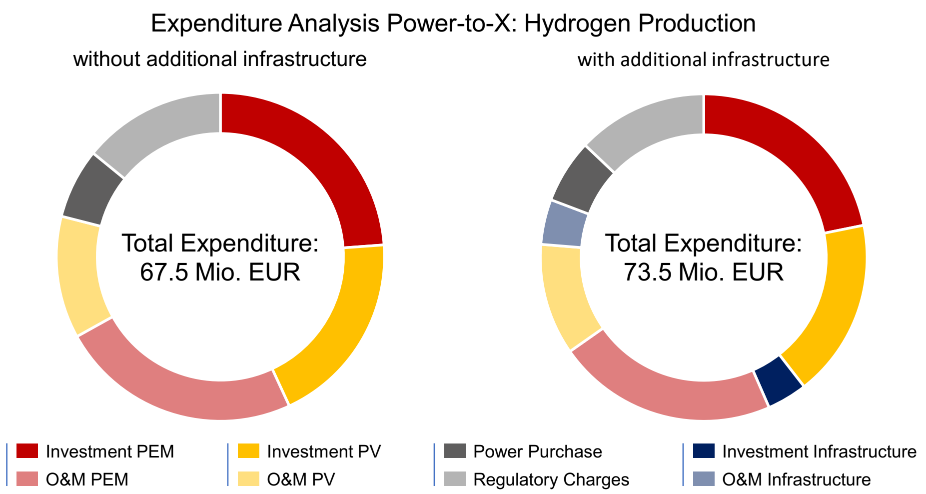

Figure 4: Share of accumulated cost components of the PtX business models over the lifetime

The PEM accounts for more than 23.9 % of the accumulated expenditure over a lifetime of 67.5 million EUR (figure 4). Investment and O&M expenditure contribute to the same extent to the total expenditure. The expenditure of the PV plant is mainly driven by investment expenditure (19,3 %). In the case of the additional transportation infrastructure via pipeline, the cumulative expenditure increases to 73.5 million EUR and is still mainly driven by the PEM (21.8 %). The contribution of the PV plant declines to 17.6 %. The investment of the pipeline infrastructure accounts for 4.0 % and the O&M expenditure of the pipeline for 4.5 % of the accumulated expenditure.

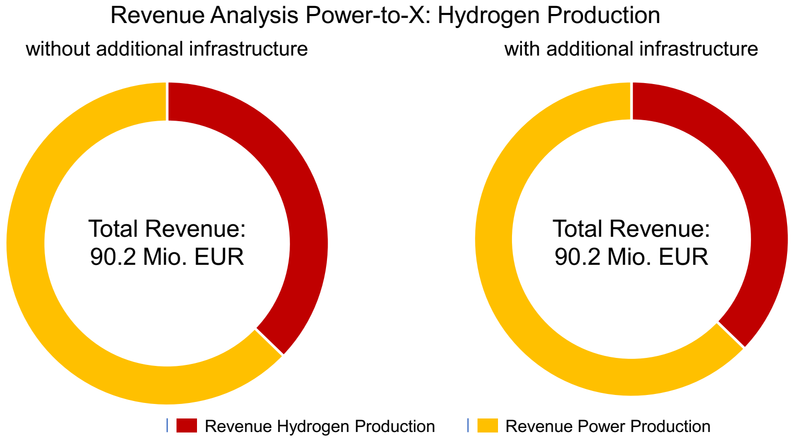

Figure 5: Share of accumulated revenue components of the PtX business models over the lifetime

The revenue structure of both business cases is the same, as the pipeline does not influence the revenue streams (figure 5). In both cases, most of the total revenue (90.2 million EUR) comes from the sale of electricity generation on the wholesale market. Only 37.2 % of the revenue is generated by hydrogen production.

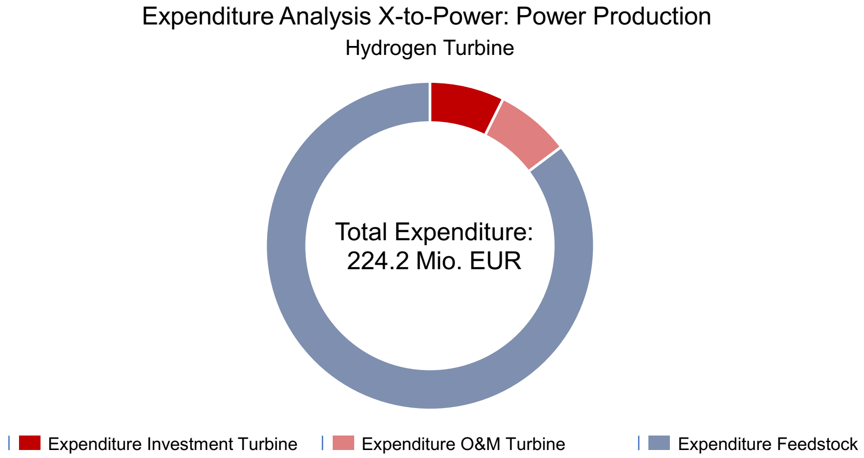

Figure 6: Share of accumulated cost components of the XtP business model over the lifetime

In contrast to the PtX business cases, the XtP case with the gas turbine has a positive NPV of 1.4 million EUR. The expenditure of the XtP business case (figure 6) of the hydrogen turbine is mostly characterised by expenditure for hydrogen procurement (feedstock). The expenditure of the investment and O&M contribute 7.4 % each. Total expenditure over lifetime is 224.2 million EUR.

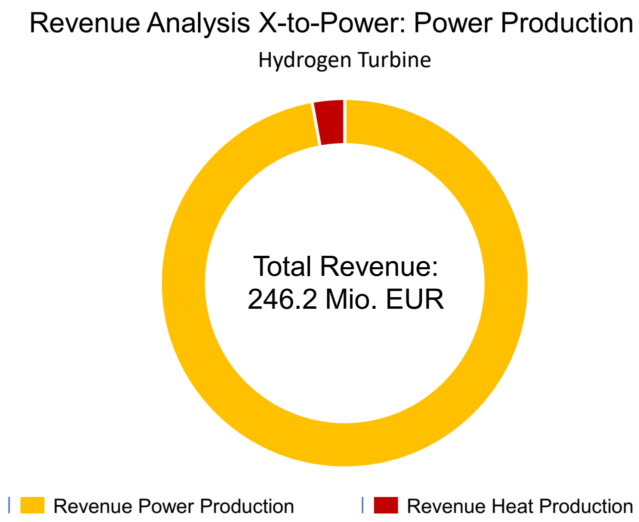

Figure 7: Share of accumulated revenue components of the XtP business model over the lifetime

The total revenue of the hydrogen-driven gas turbine is 246.2 million EUR over the lifetime. The majority is accounted to the sale of power on the wholesale market (figure 7). The share of power sales is 97.2 % compared to only 2.8 % of the revenues generated by the sale of heat.

3.2 Impact of input prices on the profitability

The results show that the production of green hydrogen based on own renewable electricity generation does not enable an economic business case under current framework conditions. Furthermore, the revenue is mainly generated from the sale of PV power on the wholesale market. This is valid for both, the PtX case with and without the consideration of additional infrastructure.

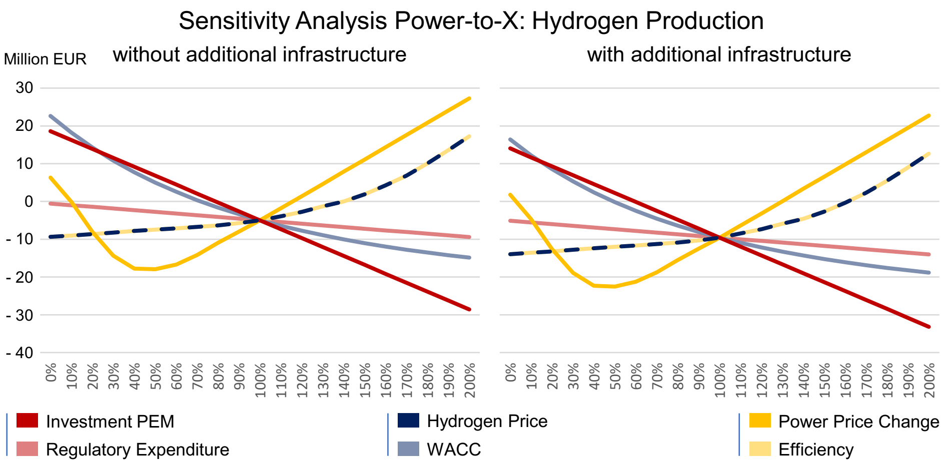

Figure 8: Sensitivity results for the NPV of the PtX business models

In the case of the PtX business model without additional infrastructure, the investment costs of electrolysis, the WACC and the hydrogen price offer a possibility to realise a positive NPV (figure 8). Low investment costs or a low WACC show the highest potential to enable positive business cases. If the WACC is below 70 % of the assumed 7 %, a positive NPV can be achieved. The influence of the WACC is important, as it is usually mainly influenced by the debt capital provision. Consequently, a market environment with low interest rates is favourable for business models. In contrast, high interest rates and shares of debt or high interest rates on equity have a negative impact on the business model. A positive NPV is also possible at 70 % of the assumed investment costs of 1610 EUR / kW of the PEM. If the hydrogen price rises to 150 % and thus to over 135 EUR / MWh, then a positive NPV can also be achieved by using the electrolysis. This applies similarly to the change in efficiency. In contrast, a decrease in regulatory expenditure cannot enable a positive NPV.

Another important aspect is the consideration of different markets. This becomes evident considering the possibilities in the electricity market or hydrogen sales. Lower power prices can ensure a positive business case, as it favours hydrogen production but cannot compensate for the expenditure of the PV plant in all cases. Higher prices on the electricity wholesale market increase production cost but also increase the incentive to sell the power of the PV plant instead of using it as input for the electrolysis. This effect results in low hydrogen production and income is increasingly provided by the PV plant. Thus, higher power prices do not only affect hydrogen production directly but also indirectly as they jeopardise the use of renewable energy by the PV plant in the own hydrogen production.

In the case of PtX with additional infrastructure, the level of NPV is mainly shifted downwards. Thus, low WACC and investment cost enable profitable business cases. For a positive NPV, the investment costs must fall to 50 % and the WACC to 40 % of the input values. High power prices also lead to a positive NPV, but only due to power production. Compared to the analysis without infrastructure, a positive business case is possible by further increasing the hydrogen price to 170 %. Similarly, an increase in regulatory levies worsens the business case.

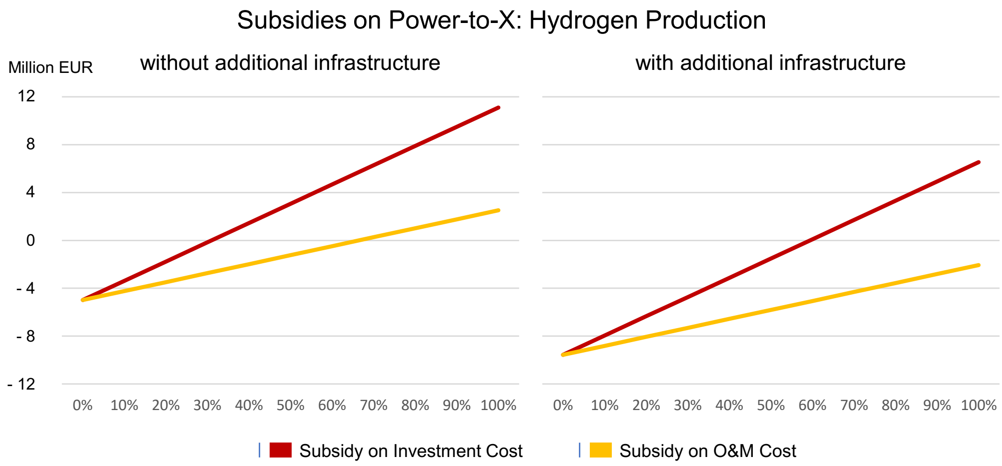

Figure 9: The impact of subsidies on the NPV of PtX business models

The impact of public subsidies also shows that investment costs are an important factor in realising positive NPVs (figure 9). The direct support of the investment ensures profitable business cases in both PtX cases. The slightly higher values when the NPV becomes positive compared to the sensitivity analysis above can be explained by the fact that although part of the investment cost is covered by another source, the actual amount of the investment is not lower. Thus, the direct subsidy of investment cost only does not affect the O&M costs, as these are accounted as a share of the effective investment costs. Supporting annual O&M costs can also contribute to profitability. However, in this case, a positive NPV is only given in the PtX case without additional infrastructure and for this, over 70 % of the O&M costs need to be covered. In the case of additional infrastructure, a positive NPV cannot be realised by subsidising the O&M cost. In both cases, the direct subsidy on investment costs is the more effective option compared to the subsidy of O&M costs.

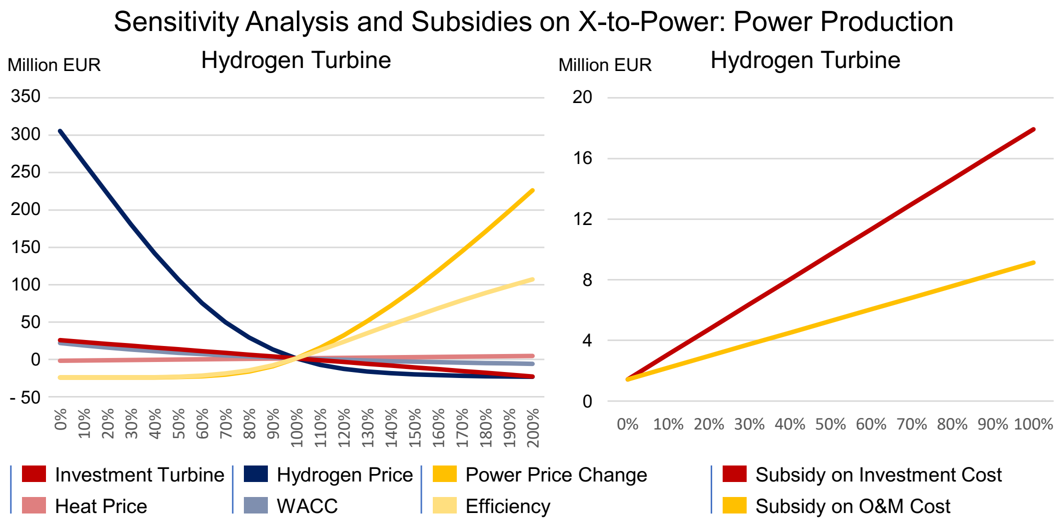

Figure 10: Sensitivity of the NPV (left) and the impact of subsidies on the NPV (right) of the XtP business model

The positive NPV of the hydrogen turbine business case is depressed by higher costs but remains positive in most cases (figure 10). The NPV becomes negative in case of a 50 % lower heat price. This shows that although heat is only a small part of the total revenue, the business model is sensitive to a change in revenue. The parameters hydrogen price, electricity price and efficiency have a higher impact on the NPV. Due to the high share of feedstock cost, an increase of the hydrogen price by 10 % or a reduction of the power price by 10 % can push the NPV into negative values. The sensitivity of the feedstock cost shows that renewable hydrogen must be available at competitive prices. The lower the price, the better for re-electrification. The higher the price of hydrogen, the higher the electricity price that is necessary for economic viability. The gap needs to be large enough regularly to ensure economic viability. An increase to 120 % of the investment costs also creates a negative NPV. Due to the already positive NPV, subsidies further increase profitability, but as higher investment costs affect the NPV they can become relevant. As in both PtX business models, direct subsidies on investment costs are more effective than subsidies on O&M costs.

4. Discussion

The results show that electrolysis in combination with own renewable electricity production cannot be operated economically under current market and political conditions. In the case of further and necessary infrastructure for hydrogen transportation, the economic situation continues to decline. Revenues are mainly generated from the sale of power due to high power prices on the one hand and low hydrogen prices on the other side. Without a sufficient guarantee of demand at sufficiently high hydrogen prices, electrolysis cannot be operated profitably. This could be created by implementing an own market for green hydrogen in combination with obligatory deployment quotas in the demand sectors as fossil-based hydrogen is significantly cheaper.

Furthermore, the impact of political measures by changing the framework conditions became evident. Changes to the levies have already been realised but even without additional fees, the PtX cases are still unprofitable. Thus, further support by subsidies could help to achieve economic viability. As power for electrolysis is produced by own capacities, the direct support of the investment cost is the most promising approach. It should be mentioned here, however, that with a PEM, a comparatively expensive technology was selected. In the case of an AEL, the profitability could be already possible at current investment costs provided in table 2.

If required, the infrastructure has a negative impact on profitability. Even a doubling of hydrogen prices does not lead to profitability under the given conditions if infrastructure is considered. This shows that for a large-scale hydrogen economy and profitable business cases, the transport issue is crucial. Currently, only local hydrogen networks exist. New projects must also consider connections between production and consumption. A limitation of the model is, that the investment is completely covered by the business model. The investment could be shared between the hydrogen producer and the customer. Further factors, such as the planning for public hydrogen transportation networks, must also be considered. Initial ideas for hydrogen transportation grids exist already and could diversify the investment risk, involving grid customers only in the form of grid fees. [66].

XtP business cases could be realised economically at current market conditions. Hydrogen turbines benefit from the high electricity prices in relation to the prices for fossil hydrogen. However, as only green hydrogen ensures no negative impact on greenhouse gas emissions, this conflicts with profitability. High electricity prices support the XtP business model but jeopardise the PtX business model for green hydrogen and vice versa. Higher hydrogen prices would enable profitable business cases of PtX but then negatively affect XtP. This conflict cannot be easily resolved. In the case of the hydrogen turbine, other markets such as a balancing market could be considered, or an adapted market design with e.g., capacity markets could enable revenues beyond the wholesale market. This is relevant as hydrogen will play a crucial role in the future electricity system [67] and viable business cases for reconversion are necessary. In this respect, the subsidies are not necessary at current market prices. But as soon as more expensive green hydrogen is used, it appears to be useful to help the business cases that will be necessary for the future to become viable.

It should be noted that only measures with a direct impact on the business models are considered by the $OBMET_{SC}$. Indirect measures, such as the rising price of CO_2, are not included. Also, regulatory options such as guaranteed sales quotas are only effective if the linked price generates a sufficient return. The level of detail is reduced due to the generic applicability along the sector coupling value chain. Thus, the technology under consideration is limited in terms of the number of required input values and aspects such as start-up times and partial load ranges are not integrated. However, this does not stand in the way of an adequate quantification of PtX-to-power business models depending on regulatory, technical, and economic framework conditions.

5. Conclusions

The paper investigates green hydrogen production and use under the current political framework in Germany with currently high electricity prices. For this purpose, the $OBMET_{SC}$ is presented as a framework to assess sector coupling business models. An application of the tool beyond Germany is pending but possible by customising the input data including RE generation data and market data.

The results conclude that PtX business cases are currently not economically viable while XtP business models are. Further research is required to find a way of exploiting the potential of all parts of the value chain as their success is mutually dependent: Firstly, profit from the low levelised cost of electricity of RE secondly, thereby supporting profitable PtX business cases and thirdly, all these by providing low-cost green hydrogen for XtP business cases. Measures such as an adaptation of the market design are plausible to raise the potential of hydrogen business models of sector coupling and to foster the energy transition.

Author Contributions

This paper is based on the results of analyses by J.G. with contributions by A.H. The methodological approach of the paper was developed by J.G. and A.H. Together with J.M.-K., they developed the concept and approach of the paper. The tool $OMBET_{SC}$ was mainly developed by A.H. and further improved by M.L. and J.G. The data used in $OMBET_{SC}$ was mainly surveyed by A.H. and supported by J.G. The main parts are written, and visualisations created by J.G. and A.H. The writing and editing process was further supported by M.L. The research was initiated by J.G. and J.M.-K and J.G. managed the editing process. All authors have read and agreed to the published version of the manuscript.

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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.

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