elyntegration

Grid Integrated Multi Megawatt High Pressure Alkaline Electrolysers for Energy Applications

Final report on most attractive business models and value chain proposition

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1 EXECUTIVE SUMMARY

1.1 New Business Opportunities due to Grid-Integration

The technological enhancements of electrolyser subsystems pursued by the ELYntegration project enable highly dynamic electrolyser operation schemes. This increased flexibility opens new business opportunities in terms of fluctuating power supplies as seen within power markets with a high share of renewable energy sources in the generation system.

This deliverable presents the results of task 2.3 of the ELYntegration project. The objective of this task is the analysis and evaluation of the impact of a changing power system environment with high shares of renewable energies on the efficiency of new potential business models for water electrolysers. These future power system related applications for electrolysers include the participation in the **spot market for electricity**, the provision of system services at **control reserve markets** and the provision of **grid services** for grid operators.

The focus of this investigation lies on the opportunities given by future European power systems of high shares of renewable energies. The evaluation of business models presented here is therefore directed towards general interrelationships between electrolyser operation, different power markets and potential electrolyser revenues. Specific and detailed national business cases as well as an in-depth cost-breakdown of the ELYntegration electrolyser through life-cycle cost analysis will be investigated in a later stage of the project. Even though this deliverable does not focus on a detailed evaluation of different sectors with renewably generated hydrogen demand, potential hydrogen markets were discussed in order to identify most promising hydrogen sales opportunities.

1.2 Identification of Promising Future Business Models

In order to identify and develop new potential business models for electrolysers, relevant markets for electrolyser applications were analysed and corresponding business opportunities identified. This includes the wholesale markets for electricity, control reserve markets, markets for grid services and hydrogen markets.

Electricity Markets

In terms of electricity markets, two options for electricity purchase for electrolysers exist. One is the procurement of electricity with long-term contracts. These contracts neglect optimization possibilities for electrolysers with high dynamic capabilities. The other option is short-term procurement of electricity at the spot market. **Spot markets for electricity offer optimization possibilities for flexible electrolyser units.** At these markets, it is possible to profit from low electricity prices at hours of low residual demand. In case of high dynamic capability of the electrolyser, a spot market price driven electrolyser dispatch can lead to profit gains (see Figure 5).

End-User Price for Electricity

An end-user of electricity such as an electrolyser usually does not face the wholesale price determined at the electricity markets. End-user prices for electricity can be significantly higher than the wholesale price due to payments for supply, use of system charges and taxes and levies. Consequently, **the efficiency of future business models for electrolysers is highly dependent**

on national regulation in terms of end-user price elements on top of the wholesale price. Exemptions for electrolysers from some of these price elements are possible under specific circumstances or are at least discussed for future electrolyser applications within Europe. Potential exemptions from these surcharges might therefore be crucial for the economic efficiency of electrolyser business models.

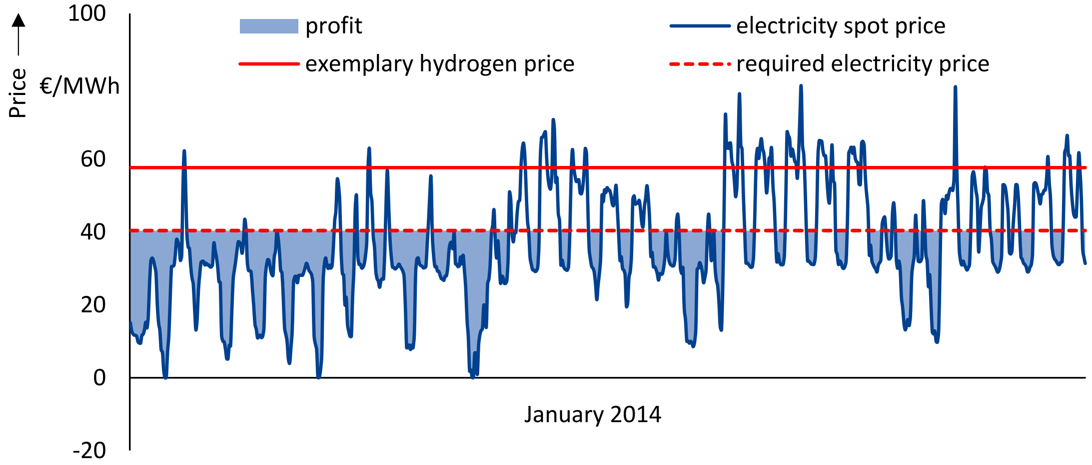


Figure 1: Exemplary electrolyser dispatch in January 2014 for Germany

Control Reserve Markets

In order to maintain a stable and reliable system operation, transmission system operators provide system services which include frequency stability through control reserve. The increasing amount of intermittent power feed-in from wind and solar power plants within Europe not only leads to more volatile spot market prices for electricity, but also to more volatile prices for control reserve. As a result, **new electrolyser business models also arise within control reserve markets in case of flexible electrolyser operation capabilities**. Those applications may include different types of control reserve including frequency containment reserve (FCR), automatic frequency restoration reserve (aFRR), manual frequency restoration reserve (mFRR) and replacement reserve (RR).

Grid Services

Apart from providing flexibility within control reserve markets, electrolysers are also able to **provide flexibility towards grid operators in order to enable a secure grid operation** by removing congestions within their grids e.g. by absorbing renewable energy that would otherwise be curtailed. Currently, no regulation or market design for such electrolyser applications exist.

Green Hydrogen Demand

Taking into account European decarbonisation goals, a low greenhouse gas (GHG) emission impact is essential for future production and use of hydrogen. Therefore, especially hydrogen production based on renewable energy sources is necessary. This renewably generated hydrogen shows the potential of GHG emission reduction for various sectors (industry, mobility, electric power system, natural gas system). In order to classify hydrogen produced via water electrolysis as green hydrogen, it is necessary to ensure that the electric energy consumed by the electrolyser is generated by renewable energy sources. **Guarantees of origin for electric energy can justify a declaration of electrolyser hydrogen to be "green"**.

Hydrogen Prices

Highest hydrogen prices can be expected within the mobility sector. Due to competition by SMR hydrogen production the expected hydrogen prices for industrial end-users are significantly lower. The lowest hydrogen prices can be expected for hydrogen or synthetic methane injection into the natural gas system. However, in case of potential future recognition of green hydrogen injection in terms of specific feed-in tariffs, higher hydrogen prices can be expected. Consequently, it can be expected that **business models directed towards the mobility sector are especially promising**. As off-site hydrogen production results in additional costs due to distribution and compression of hydrogen, electrolyser installations should be located within the vicinity of the hydrogen end-user.

1.3 Investigated Future Business Models

Nine different business models including **cross-commodity arbitrage trading**, **control reserve market participation** and **grid services** are addressed within this study. The aim is to provide an analysis of possible net margins from the different possible operational strategies as well as possible profits from the combined participation at different markets.

Especially for the mobility sector, high hydrogen prices can be expected. Therefore, within this deliverable, the presented electric power system based business models are applied to a scenario of **green hydrogen production** to be sold to hydrogen refuelling stations for **mobility applications**. Net margins for the application of these business models to other hydrogen demand sectors, deliverable 6.4 of ELYntegration project [1] presents sensitivity analyses.

1.4 Method for Evaluation of Future Business Models

The evaluation of new potential business models for electrolysers is done by an estimation of future net margins (see Figure 2). Based on the calculation of operational costs and the investment costs for the electrolyser on the one hand, and future revenues from the sales of the generated hydrogen and potential reimbursement for the provision of system or grid services, yearly net margins can be derived.

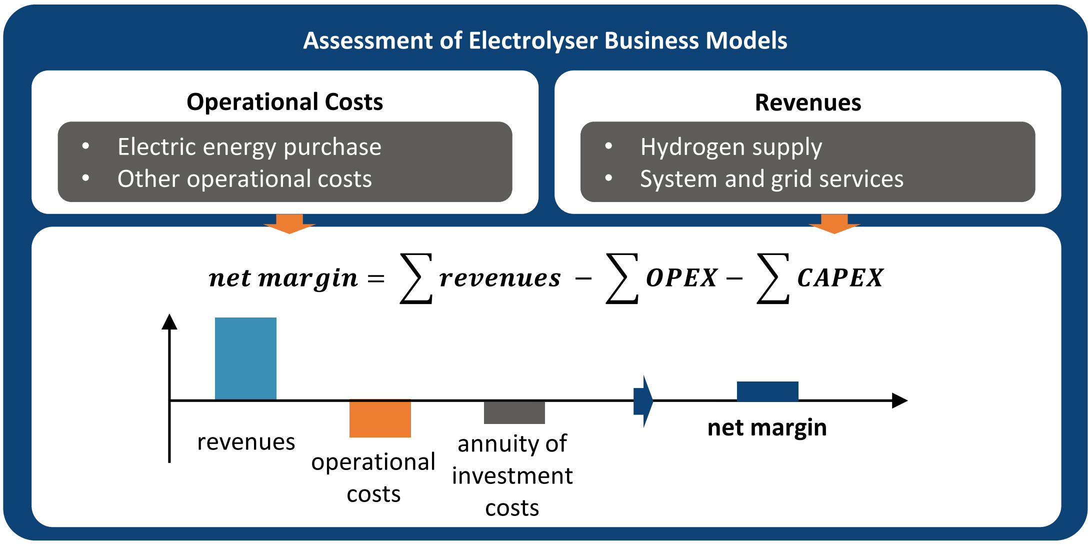


Figure 2: Assessment of electrolyser business models by calculation of net margins

The evaluation of future business models requires to model future fundamental influences on the power system such as a rising share of RES, a rising share of storage and flexible demand units and rising CO_2 emission certificates. Therefore, fundamental simulation approaches are used in order to model the spot market for electric energy as well as the transmission grid operation. The control reserve markets are modelled via an agent-based simulation method.

1.5 Evaluation of Future Business Models

Spot Market Participation

Due to different market circumstances such as high wind or solar power generation or island situations, four different European countries are considered for the evaluation of business models directed towards spot market participation: Germany, the Netherlands, Portugal and Spain. Net margins for all four countries and times horizons resulting from cross-commodity arbitrage trading are presented in Figure 3. It is visible that developments differ between countries due to different circumstances strongly influencing potential business models for electrolysers.

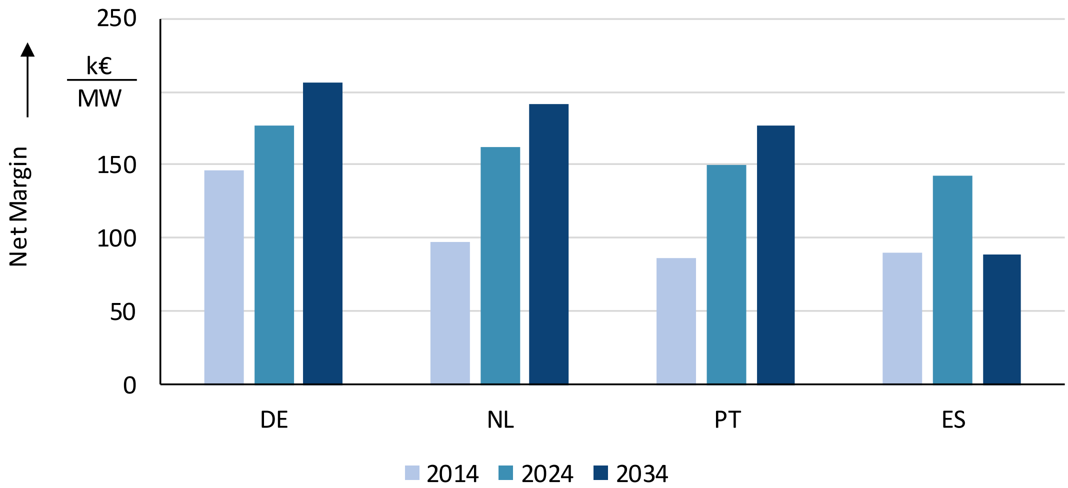


Figure 3: Net margins for 10 MW electrolyser for cross-commodity arbitrage trading

In conclusion, rising net margins can be expected for the future, when high shares of RES, especially wind power, characterize the market situation. Promising markets are those with large shares of wind turbines, because the fluctuating feed-in attributes for low market prices for electricity. Revenue increases at markets with high shares of PV may be limited at a certain level because the simultaneity of solar feed-in leads to a price reduction in only a few hours per day. Island positions of markets comprise dependencies of surrounding market areas, which have to be considered as well. Nevertheless, smoothing effects of feed-in curves should be less developed in market areas with island positions, which in turn produces peaks of low spot market prices, which may result in higher electrolyser revenues.

Control Reserve Provision

Net margins for a 10 MW electrolyser participating at the different reserve markets are investigated for Germany (Figure 4). Higher net margins compared to cross-commodity arbitrage trading can be achieved from participation in control reserve markets with positive aFRR and positive mFRR and with an optimized electrolyser dispatch.

The most profitable business models are positive aFRR and mFRR, less profitable are negative aFRR and mFRR. The required operation point accounts for higher full load hours and net margins for positive FRR. For the provision of positive FRR, the electrolyser runs between 6.5 MW and 10 MW. For providing negative FRR, the electrolyser does not exploit high spreads because it cannot run at full load in hours with a profitable cross-commodity spread. FCR has the highest prices for reserve provision. Nevertheless, FCR is not the most profitable business model because units cannot run in full load during FCR provision. The optimized dispatch returns the highest net margins compared to the other business models in all three simulated years. The optimized unit commitment of electrolysers takes not only one control reserve into account, but all reserve qualities under consideration of tender durations as well as cross-commodity arbitrage trading.

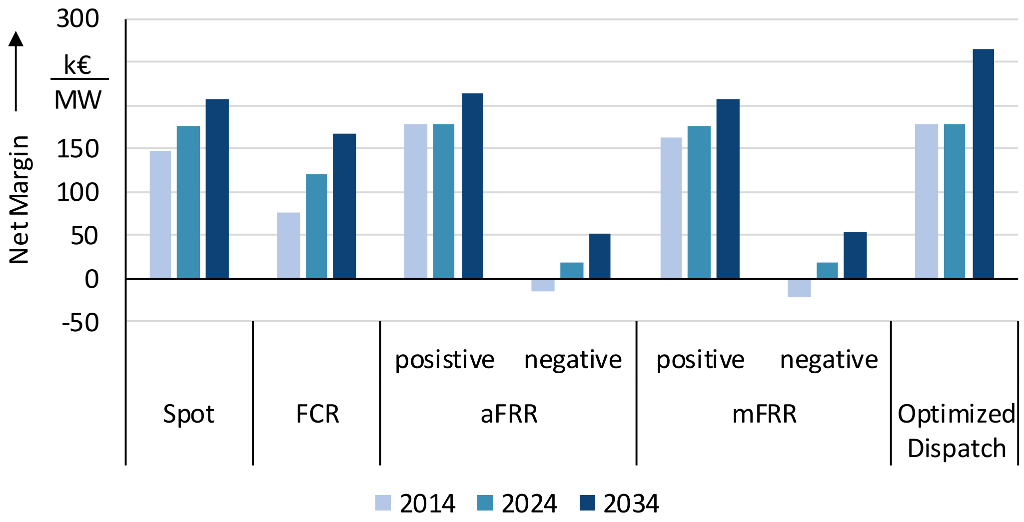


Figure 4: Full load hours and contribution margins for a 10 MW electrolyser

In conclusion, positive aFRR and mFRR are more profitable than negative aFRR and mFRR in all scenarios. A combination of participation at different markets shows promising increases of net margins. The electrolyser does not exploit high spreads between the spot market and hydrogen market when running in the operation scheme for providing negative FRR. This overturns higher prices for negative FRR than for positive FRR. High spreads between the spot market and hydrogen market are harnessed most efficiently when capacities are fully available and not reserve for negative control reserve. Lost profits of non-produced hydrogen when production flexibility is bound to control reserve tenders cannot be compensated by profits from control reserve provision. However, it can also be seen that cross-commodity arbitrage trading is only slightly less profitable in the future when reserve and spot market prices are declining.

Grid service provision

The amount of potential full load hours of an electrolyser participating in the congestion relieving process of TSO is highly dependent on its location, the future allocation of RES power plants as well as the advance of transmission grid expansion planning. Generally, grid expansion planning is directed towards a congestion free grid. Consequently, for grid service provision, **the amount of potential full load hours is rather low compared to spot market or control reserve market participation**.

Key findings

- **Cross-commodity arbitrage trading** considering the electricity market and hydrogen for mobility applications shows to **positive net margins** in all assessed time horizons and countries.
- Markets with **high shares of renewables, especially wind power**, are most promising.
- **Net margins can be increased** by the participation at **control reserve markets**.
- **Operational constraints** based on **control reserve commitments** are crucial for the assessment of profitability of electrolysers.
- **Positive aFRR and mFRR** are the **most promising** control reserve markets.

2 OBJECTIVES

The research and innovation project „Grid Integrated Multi Megawatt High Pressure Alkaline Electrolysers for Energy Applications“ (ELYntegration) is focused on the design and engineering of a robust, flexible, efficient and cost-competitive single stack multi megawatt high pressure alkaline water electrolyser. The final goal is an electrolyser design that shows the ability to provide sufficient load flexibility in order to be used under highly dynamic power supplies of power systems that are subjected to high shares of renewable energies. The corresponding technological enhancements shall open new business opportunities for electrolysers operation within future European electric power markets. Therefore, one main goal of ELYntegration is the investigation and assessment of future grid integration and future power system related applications for electrolysers. This deliverable presents the results of task 2.3 of the ELYntegration project. The main objective of this task is the analysis and evaluation of the impact of a changing power system environment with high shares of renewable energies on the efficiency of new potential business models for water electrolysers.

The classic business model for electrolyser operation relies on cross-commodity arbitrage trading between markets for electric energy and sectors having hydrogen demand using sufficient spreads between spot market prices for electricity and the price for hydrogen. While previous studies show that in future this business model might not be sufficient for cost efficient operation in the short to medium run, the ability of a highly flexible electrolyser operation as being target of ELYntegration project enables the unit not only to perform arbitrage trading but furthermore to participate in control reserve markets for electric power and provide flexibility and other grid services towards grid operators. Therefore, within this deliverable, three main energy applications are presented and opportunities for electrolyser business models are discussed:

- Participation in the **spot market for electricity**
- Provision of system services at **control reserve markets**
- Provision of **grid services** for distribution and transmission grid operators.

While the focus of the business models presented within this deliverable lies on the electric energy applications and the business opportunities given by future European power markets with high shares of renewable energies, an assessment of new potential business models also has to take into account relevant markets for sectors with green hydrogen demand, including

- industry customers of hydrogen,
- hydrogen within the mobility sector and
- hydrogen use within the natural gas system.

Therefore, in the following, the term business model for an electrolyser is defined as the combination of all relevant markets on which the electrolyser operator is participating, both for the electric power consumption as well as the sales of the generated hydrogen. This includes the development of suitable electrolyser operation schemes for the markets in question, taking into account technical restrictions given by the dynamic performance of the electrolyser and regulatory requirements for market participation.

While specific and detailed national business cases will be investigated in a later stage of ELYntegration project, the business models presented within this deliverable focus on general interrelationships between electrolyser operation and power markets with high shares of renewable energies and potential revenues to be gained.

Generally, the business models presented within this deliverable can also be applied to proton exchange membrane (PEM) electrolysers. However, this deliverable focuses on alkaline water electrolysers (hereafter referred to as electrolyser) due to the strategic goal of ELYntegration project of improving the dynamic performance of alkaline water electrolysers.

2.1 Analysis of New Potential Business Models

To define new potential business models, all relevant markets for electrolyser applications need to be analysed. Therefore, the first part of the deliverable focusses on the identification of markets that show promising opportunities for electrolyser applications directed towards electric power markets with high shares of renewable energies. A description of both electric power markets and relevant hydrogen markets is given including a discussion under which circumstances an electrolyser participation within these markets is permitted.

2.2 Development of New Potential Business Models

Based on the analysis of potential future markets for electrolyser applications, specific business models are developed focussing on new business opportunities that arise within future electric power markets. These models involve participation at the spot markets, the control reserve markets and within the congestion relieving process of transmission grid operators. In case additional revenues for the operator of the electrolyser can be expected and regulation is not contradictory, participation on several of these markets is considered. For each of the developed business models corresponding operation schemes are derived that determine under which circumstances and market situations the electrolyser is started up or shut down throughout the year.

2.3 Evaluation of New Potential Business Models

The third and fourth part of this deliverable deals with the evaluation of the new potential business models analysed and developed in the previous steps and shall give an assessment in terms of short-, medium- and long-term opportunities for electrolyser applications. An estimation of future full load hours and net margins will be given in order to identify most promising business models. A full economic assessment of specific business cases including a thorough evaluation of investment costs in terms of life-cycle costs analysis is topic of future work packages within the ELYntegration project and is therefore not part of this deliverable.

In order to assess future net margins, it is crucial to have reliable estimates on prices for the spot and control reserve markets for electricity. A reliable assessment for net margins especially requires estimates not only on average future electricity prices but on the future hourly progression of spot and control reserve market prices throughout the year. Therefore, within the third part of this deliverable, fundamental approaches for deriving time series of future electricity prices are presented. The underlying complex spot and control reserve market simulations are then applied for models of the future European generation system in order to determine hourly time series for electrolyser operation exemplarily for years 2014, 2024 and

2034. In order to assess future full load hours for business models based on a provision of grid services by electrolysers e.g. within the transmission system congestion relieving process, additional simulation methods are required. Therefore, a fundamental redispatch model is presented simulating future remedial measures taken by the transmission system operators in order to eliminate congestions within their transmission grids. This method is then applied exemplarily for Germany estimating the hourly operation of electrolysers participating in this process.

For the identification of main drivers and fundamental risks to the efficiency of potential business models, a sensitivity analysis of main influencing factors such as the hydrogen price or the future share of renewable energy sources in the European generation system is performed. The results of this sensitivity analysis are presented in deliverable 6.4 of the ELYntegration project [1].

3 ELECTROLYSER BUSINESS MODELS

3.1 Potential Electrolyser Business Models

This deliverable focuses on the economic potential of highly dynamic electrolyser operation capabilities in terms of participation in electricity markets that are subjected to high shares of renewable energy sources. Consequently, new potential business models for water electrolysers are investigated in detail that are directed towards cross-commodity arbitrage trading at the European spot markets for electricity as well as other marketing opportunities at future flexibility markets of system and grid service provision for grid operators. While the focus of this deliverable does not lie within the hydrogen demand side, a comprehensive analysis of future electrolyser business models also requires a discussion on possible future hydrogen demand sectors and their effect on the hydrogen price. The results of this analysis are portrayed in the following.

3.1.1 Electricity Markets

Generally, two options for electricity purchase for electrolysers exist. One is the procurement of electricity with long-term contracts. The other option is the short-term procurement at the spot market for electricity.

A long-term contract is a classical choice for industry loads where a defined amount of electricity is delivered at every hour for the same price. Long-term contracts are easily manageable and minimize risks but neglect optimization possibilities for flexible units which may produce higher revenues at more volatile markets.

An optimized approach would be the purchase of electricity on short-term markets. There, it is possible to profit from low electricity prices at hours of low residual demand, given that the unit is flexible enough to ramp up and down. As the electrolyser developed within the ELYntegration project is flexible enough that it may participate at short term and flexibility markets for electricity, the opportunity of resulting revenues from short term markets are assessed. Before quantitative analyses are conducted, first the current and future markets for electricity are analysed in order to gain overall knowledge. For that, two markets are analysed further: the spot market for electricity and the control reserve market.

The spot market for electricity is used for the day-ahead junction of load and generation. The spot market designs of the different European countries generally work based on the same principle: with an auction where physical load and generation are matched. Close of trading is at 12 o’clock at noon for the next day and the market is cleared using a unit pricing model based on marginal costs of participating power plants. Different European markets are coupled, which means that trades may be done between market areas using available transmission capacities, enabling arbitrage and leading to an approach of prices [2].

The current developments of higher shares of fluctuating renewable energy systems (RES), which are mainly wind turbines and photovoltaic power systems, have several consequences for the short term markets. One is the decrease of mean electricity prices on the wholesale markets due to the merit order effect, another one is a rising volatility of market prices. As the price is set considering load and available capacity, the volatility is determined by load, the RES feed-in and the availability of other power plants. There, the combination of load volatility and increasing shares of volatile RES with zero generation costs will lead to increasing price volatility in the future.

This offers a chance for a new operation strategy for electrolysers: If it is flexible enough and shuts down and ramps up quickly and cheaply enough to allow for a spot market price driven dispatch, an electrolyser may benefit from cheap prices and skip times of high electricity prices in operation. As the electricity price is more volatile than the hydrogen or natural gas prices, the dispatch of an electrolyser should be optimized against the electricity price. Assuming a hydrogen price of 3 €/kg and an electricity demand of 52 MWh/t for the electrolyser, this would lead to the exemplary spot-market electrolyser dispatch depicted in Figure 5 based on the spot market prices for electricity in January 2014 in Germany [2]. The required electricity price indicates the maximum price for electricity at which the spread between the procurement cost of electricity and revenues from hydrogen sales is big enough to cover the conversion losses of the electrolyser. This operational strategy thus uses cross-commodity arbitrage trading as a business model. A higher spread between the two commodity markets leads to a higher profit for the electrolyser operator. This may on the one hand come from lower electricity prices, but on the other hand also from higher sales prices. In order to assess sales prices, the hydrogen market is analysed in section 3.1.5.

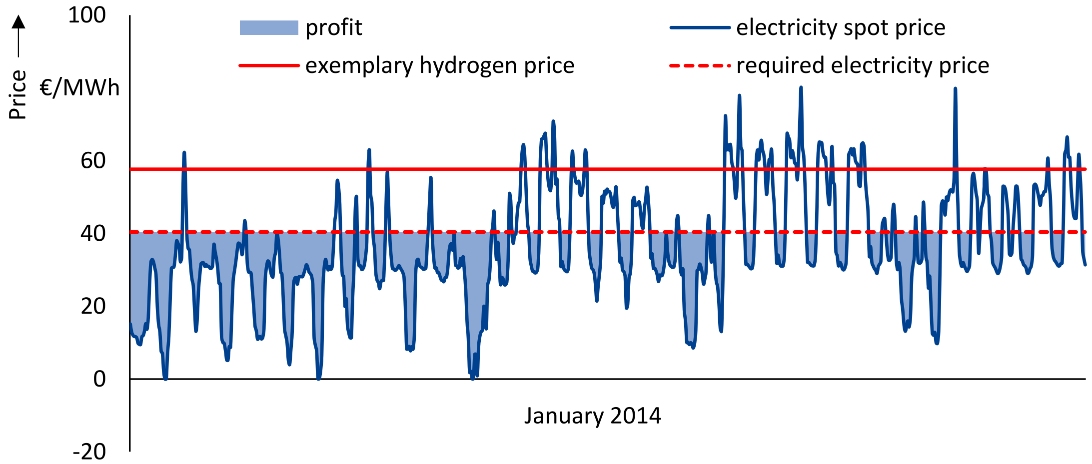


Figure 5: Exemplary electrolyser dispatch in January 2014 for Germany

In order to assess future market prices, fundamental influences on prices need to be considered. The future of the electricity market is characterized by a changing composition of its power fleet: a rising share of RES and a lower share of conventional power plants. Because intermittent RES are powered by wind and sun, they do not have to incorporate fuel prices into their marginal cost calculation and thus produce electricity with marginal costs close to zero. With higher shares of RES, this leads to lower electricity prices in times of high RES feed-in due to the merit-order effect. Higher shares of RES also result in lower residual load and more times where residual load may become negative in the future, possibly leading to negative prices. Besides high RES feed-in, low load and high opportunity costs in terms of start-up and shut-down cost of conventional coal and nuclear power plants influence negative prices [3].

Another factor for the consideration of future prices is the share of storage and flexible demand units within the respective markets. Those include pump storage units, batteries, possibly electric vehicles, electrolysers but also flexible loads in terms of demand side management (DSM) from industry and households. The future development of storage and DSM may influence the feasibility of electrolyser business models, because those technologies may smooth the price volatility with peak-shaving.

Furthermore, as thermal power plants usually set the price with their marginal cost in uniform pricing markets such as the spot market, their fuel prices (including coal, gas, CO2 emission costs, etc.) are the main influencing factor for the electricity prices. The future development of those prices is essential for a future assessment of European electricity price developments. Especially CO_2 emission certificate prices are predicted to rise in the future, which would lead to higher electricity prices. Predictions for other primary energy prices as well paint a picture of slightly higher prices in the future. Another shift in electricity prices comes from trends of nuclear and coal phase-outs seen in some European countries such as Germany. With this decline in conventional power plants and increasing RES shares, flexibility options become a basis for a successful market operation in Europe with volatile prices that may offer chances for electrolyser applications [4].

The intraday spot market is another short-term market which may be a possible procurement option. The intraday market though does not have a uniform price but is a pay-as-bid market. Intraday prices deviate from day-ahead spot markets if power plant outages and RES forecast errors require very short term flexibility, but on average, day ahead and intraday spot market are arbitrage-free, which means that mean price values are the same. Thus, an intraday market operation scheme of an electrolyser looks similar to the day-ahead spot market operation scheme. Revenues from intraday markets may be a bit higher than from day-ahead trades, but prices are lower than on control reserve markets. Thus, in order to analyse chances on very short-term markets, reserve markets are considered in more detail.

3.1.2 End-User Prices for Electricity

For the evaluation of potential business models, it is not sufficient to solely investigate the wholesale price determined at the electricity markets. End-user prices for electricity that apply for electrolyser operators can be significantly higher than the wholesale price due to payments for supply, use of system charges and taxes and levies. These price elements are highly dependent on the national regulatory framework. Consequently, the end user prices within European countries differ significantly (see Figure 6). The efficiency of potential business models for electrolysers is therefore not only dependent on the wholesale prices, but also on the regulatory framework in each country. Exemptions for electrolysers from use of system charges, RES subsidy surcharges, specific taxes or levies are possible under specific circumstances or are at least discussed for future electrolyser applications within Europe. For example, electrolysers in Germany are exempted from network costs. A detailed analysis of end-user prices for electrolysers can be found in deliverable 2.1 of the ELYntegration project [5].

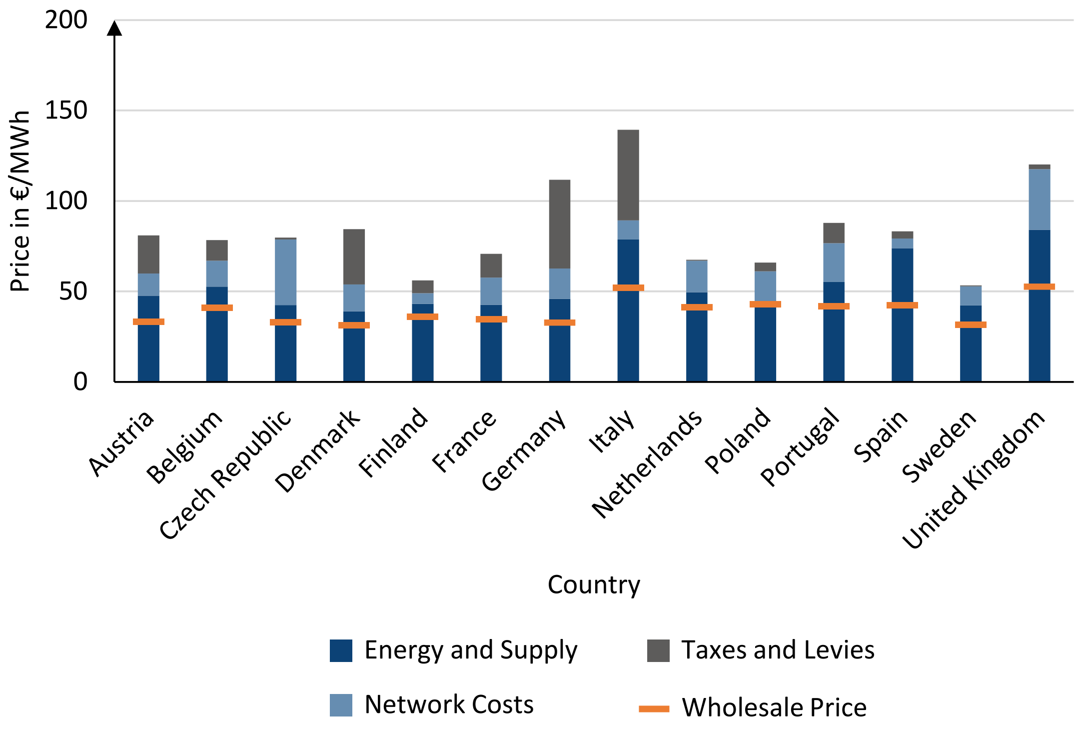


Figure 6: Average electricity prices and their break down into components for industrial consumers (20 GWh – 70 GWh) in 2014 by country [6] [7] [8] [9]

3.1.3 Control Reserve Markets

In order to maintain a stable and reliable system operation, transmission system operators provide system services which include frequency stability through control reserve. Transmission system operators represent possible customers for electrolyser applications if the electrolyser can comply with requirements during operation. Those applications may include different types of control reserve. In order to assess the suitability of electrolysers for different services, regulatory and technical requirements as well as possible operational schemes were analysed in detail in deliverable 2.1 of the ELYntegration project [5]. The investigated control reserve markets include the frequency containment reserve (FCR), automatic frequency restoration reserve (aFRR), manual frequency restoration reserve (mFRR) and the replacement reserve (RR). Figure 7 shows the succession of these different types of control reserves, which are consecutively activated after a disturbance.

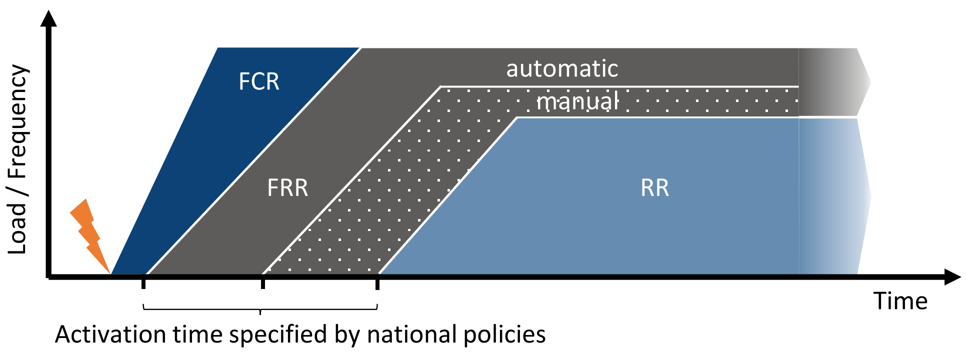


Figure 7: Consecutive activation of different types of control reserve

3.1.4 Grid Services

Apart from providing flexibility within control reserve markets, water electrolysers are also able to provide flexibility towards grid operators in order to enable a secure grid operation by removing congestions within their grids. In the following, possible opportunities for future business models in terms of grid services are analysed for transmission system operators (TSO) and distribution grid operators (DSO).

Grid Services for TSO

The market based power plant dispatch leads to frequent congestions within transmission grids. Within Germany for example, wind turbines in the northern and eastern regions cause high power flows to the load centres in the south. According to European regulation [10], each TSO must ensure that the transmission system remains in normal state and is responsible for managing operational security violations. These violations include congestions according to the (n-1)-principle. This principle states that the voltage at all nodes and the current on all lines have to be kept under operational limits in every relevant contingency situation, e.g. the outage of a large power plant or the tripping of a transmission line. In case the (n-1)-principle is not satisfied, remedial measures need to be applied by the TSO to relieve all relevant congestions and ensure system security.

TSO implement remedial measures in the day-to-day operational planning process (Day-Ahead Congestion Forecast) and real-time system operation (Intraday Congestion Forecast). The available measures are regulatory distinguished between non-costly network related measures, including topology modifications (e.g. switching lines on/off), transformer and reactive power compensation tapping, and costly market related measures with intervention in the power generation dispatch based on the power market outcome and in the load of contracted end-users of electric energy. Due to their costs, market related measures may only be implemented if no more network related measures are available for relieving congestions. Market related measures include countertrading, redispatch (including start-ups) of conventional power plants, contracted sheddable loads, start-ups of reserve power plants, curtailment of RES and load shedding as an emergency measure. Possible applications within this process of market related measures for water electrolysers mainly lie within the redispatching process of power plants and contracted loads as well as the curtailment of RES.

Especially in case the RES expansion advances more rapidly than a corresponding grid expansion, the amount of unused energy due to curtailment of RES increases. Hence, current discussions include the potential introduction of another element within the redispatch process. The idea entails shiftable loads that are willing to increase their power consumption in case curtailment of RES could thereby be avoided. In Germany, the possibility of introducing such an element is already mentioned within § 13 of the federal law on energy management. However, so far no regulation or market design for such an element exist and is therefore currently not applied. Consequently, also the amount of potential reimbursements or reductions of electricity price for these kinds of flexibility providers remain unclear.

In order to assess potential electrolyser operational hours according to these concepts, a transmission grid simulation including an estimation of redispatch measures is conducted within this study. The applied redispatch model is briefly portrayed in section 4. The results of this simulation will be presented in chapter 5.3. Results of the corresponding business models will be presented in chapter 6.3.

Grid Services for DSO

The strong increase of RES shares is not only problematic for the transmission system, but also poses new challenges for the distribution system since most of the RES units are not connected to the transmission but to the distribution grid. This leads to an increasing necessity of distribution grid expansion [11]. A complete expansion of the grid is economically not feasible though, because many congestions happen because of extremely high RES feed-in, which happens only in a few hours each year. This trend can currently be seen in Germany, but also happens in other European countries and will increase in the future with higher RES shares. In Germany, the current regulative approach is to allow distribution grid operators (DSOs) to consider a curtailment of up to 3 % of the fed-in energy of each unit within grid planning in order to reduce congestions and thus reduce costly grid expansion [12]. The curtailment still has to be compensated by the system operators. In order to reduce costs further, additional advances in that area are proposed. These propositions include the market-based provision of flexibility in the distribution grid. These so-called local grid services may be provided by units which are already located within the distribution grid such as generation units, but also by flexible loads such as electrolysers or batteries.

The idea is to regulate local grid congestions by contracted flexible generation or load units which may be called upon demand instead of curtailing RES or extending the grid. This may be organized within a local market for flexibility. The contracted capacity is held on stand-by, but may be used for other marketing strategies when no grid congestions appear. In order to organize the idea, the so-called traffic light concept was proposed in Germany [13].

This concept organizes the interaction between market participants and local DSOs. It is called traffic light concept because it differentiates between three different stages of the local flexibility market: The green stage, the yellow stage and the red stage. The concept is shown in Figure 8 [14].

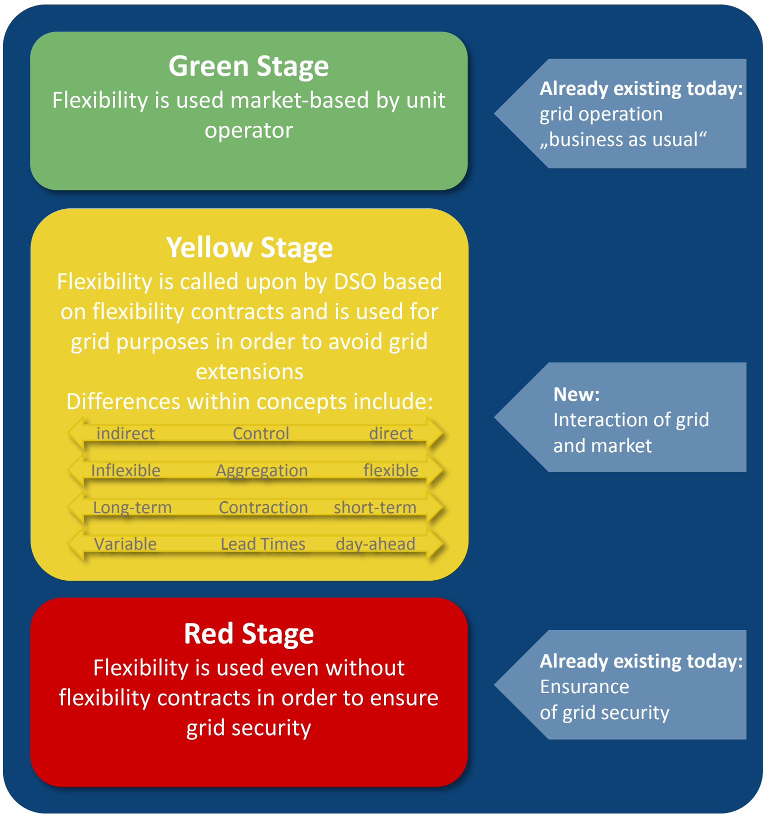


Figure 8: Traffic light concept for local flexibility markets

The stages are defined by the state of the grid. If no critical grid conditions exist within the distribution grid or the DSO may solve conditions by his own network-related measures, the green stage is active. That stage, which is also called market stage, is business as usual and nothing changes compared to normal operation. Any market participant is set in his usual market such as the wholesale electricity market. Consequently, a local flexibility market does not modify anything compared to current market setups during the green stage [14].

The yellow stage is the interaction stage between local flexibility providers and DSOs. In that stage, the DSO calls upon the contracted local flexibility capacities in order to solve expected grid congestions. The excess capacity may still be used for other operational strategies by the market participants. The contracted flexibility is compensated and this compensation is considered to cover losses that may occur from the retrieval of flexibility by the DSO. For the exact design of the yellow stage, different propositions exist. Because the traffic light concept and the local flexibility market are still theoretical ideas, those different ideas concerning control, aggregations, contractions and lead times are still in discussion [15].

The red stage is the stage where a critical grid state is diagnosed which cannot be compensated by the local flexibility that was contracted. This may lead to a disruption of the grid operation and the DSO intervenes in the unit dispatch based on classical regulations which are currently used in the same manner when such conditions occur.

The local flexibility market may be a well-suited additional business opportunity for electrolysers which participate in other markets as described before. Because the RES developments are comparatively new, this concept is a current topic for research developments [16], which means that there are no numbers or economic values for flexibility which may be considered a quantitative analysis within the ELYntegration project. Due to that fact, the concept is described qualitatively in order to give an introduction to the concept which may be quantitatively researched when reliable results of pilot projects are available in the future [16].

3.1.5 Hydrogen Markets

Grid-integrated electrolysers participating in electricity markets that are subjected to high shares of renewable energies have the potential of helping European goals of decarbonisation by production of sustainable and renewably generated hydrogen. This “green” hydrogen can be used in various end-user applications. Therefore, in order to evaluate potential new business models for electrolysers, the relevant key markets for hydrogen consumption are taken into account. The different end-user sectors of hydrogen are shown in Figure 9.

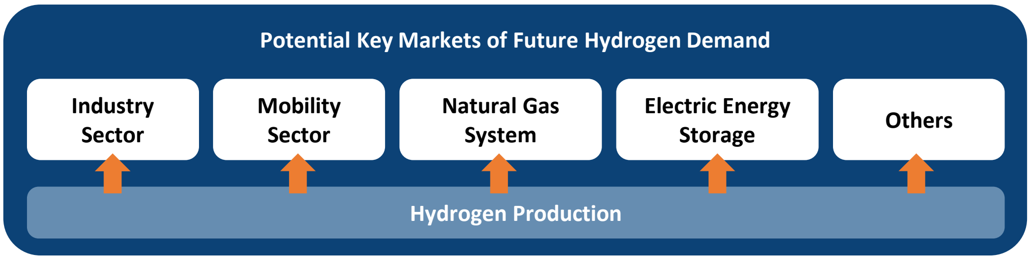


Figure 9: Potential key markets of future hydrogen demand

Hydrogen demand

The worldwide demand for hydrogen was around 43 megatons in 2010 with a yearly increase of around 1 %. 16 % of this hydrogen was consumed within Europe. Currently, the industry sector accounts for more than 90 % of the hydrogen demand [17]. Within the industry sector, 63 % of hydrogen demand originate in the chemical industry (especially ammonia and methanol production), around 31 % in the crude refinery industry and 6 % in the metal processing industry. Less than 1 % of hydrogen consumption is used in liquefied form e.g. for rocket and automotive fuels (see Figure 10) [18].

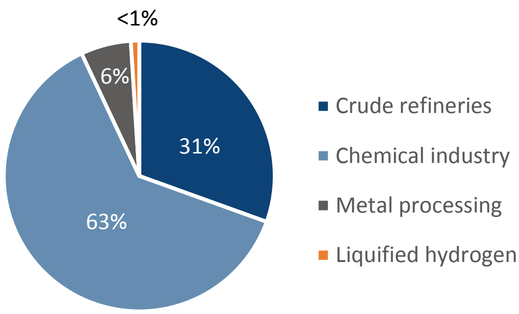


Figure 10: Share of hydrogen consumption within industry sector [18]

Currently, only smaller amounts of hydrogen are consumed within the mobility sector. So far, hydrogen mobility has not yet left the phase of demonstration projects. However, due to European goals of decarbonisation of the mobility sector and corresponding national initiatives in terms of funding fuel cell electric vehicles (FCEV) and a necessary refuelling infrastructure, an increasing demand of renewably generated hydrogen within the mobility sector is widely expected.

Another possible sector includes the feed-in of hydrogen into the natural gas grid (blending). However, the amount of hydrogen feed-in is limited to a certain volume fraction of the natural gas. For example, the maximal permissible volume for the current natural gas system is up to around 5 $\%_{vol}$ in Germany [19] [20]. On the other hand, today's amount of hydrogen injected into the natural gas grid is negligible. A direct injection of hydrogen can be avoided in case of including a methanation process that uses hydrogen and carbon dioxide in order to produce synthetic methane. In both cases, the hydrogen or the synthetic methane respectively could be used as a substitute for natural gas. Because of high investment costs for both water electrolysers and methanation units as well as low natural gas prices, currently hydrogen demand within the natural gas system or for energy storage purposes is insignificant.

Other additional future hydrogen demand sectors are still subject to research and development or within early demonstration status. These sectors in discussion include

- the co-generation of power and heat within buildings,
- fuel cell forklifts,
- autonomous power systems for stationary or portable off-grid applications and
- uninterruptible power systems.

The results of a more detailed analysis of potential current and future target sectors for hydrogen demand is presented within the market potential assessment presented in deliverable 6.4 of the ELYntegration project [1].

Temporal hydrogen demand by customers

When addressing the hydrogen demand, potential temporal variations of hydrogen demand need to be taken into account. For example, large industrial customers usually show a rather constant hourly hydrogen demand throughout the year. For other applications such as hydrogen mobility, it can be expected that the hydrogen demand is more fluctuating. Consequently, for industrial customers, the hydrogen generated by an electrolyser needs to be supplied to the customer continuously at a more or less constant rate per hour while for other customers a hydrogen supply according to a specific schedule is necessary.

While conventional hydrogen production pathways are usually able to supply hydrogen at a rather constant rate or according to a specific schedule [21], hydrogen production via electrolyser operation based on spreads between electricity and hydrogen prices itself is intermittent. In order to provide hydrogen customers according to a fixed hydrogen demand schedule, appropriate additional hydrogen storage systems are needed. This results in additional investment and operational costs and consequently influences the overall economic efficiency of specific business cases.

While this deliverable is directed towards the investigation of general electrolyser market opportunities in terms of trading at power markets of high shares of renewable energies, a detailed analysis of hydrogen demand schedules and a case-specific dimensioning of necessary hydrogen storage units is not focussed in the following. Specific national business cases will be investigated in a later stage of ELYntegration project.

Hydrogen production pathways

While industrial customers require large amounts of hydrogen, several industry processes also generate hydrogen as a by-product. Processes with large amounts of hydrogen by-product include the electrolysis of sodium chloride by the chlor-alkali process and catalytic reforming of naphtha into high-octane products within crude refinery processes. By-product hydrogen is also generated within steel industry processes like iron and steelmaking as well as coke production.

Figure 11 depicts the main pathways of hydrogen production. Steam methane reforming (SMR) uses a catalytic conversion of natural gas in order to produce hydrogen. Its technology is mature and has been widely used for supplying industry customers since the 1930s. Coal gasification uses water and coal in order to produce hydrogen among other gases. The forth pathway consists of water electrolysis. While alkaline water electrolysis can be considered as being rather mature, proton exchange membrane (PEM) electrolysis is in an early market stage while solid oxide (SO) electrolysis is rather within research and development stage.

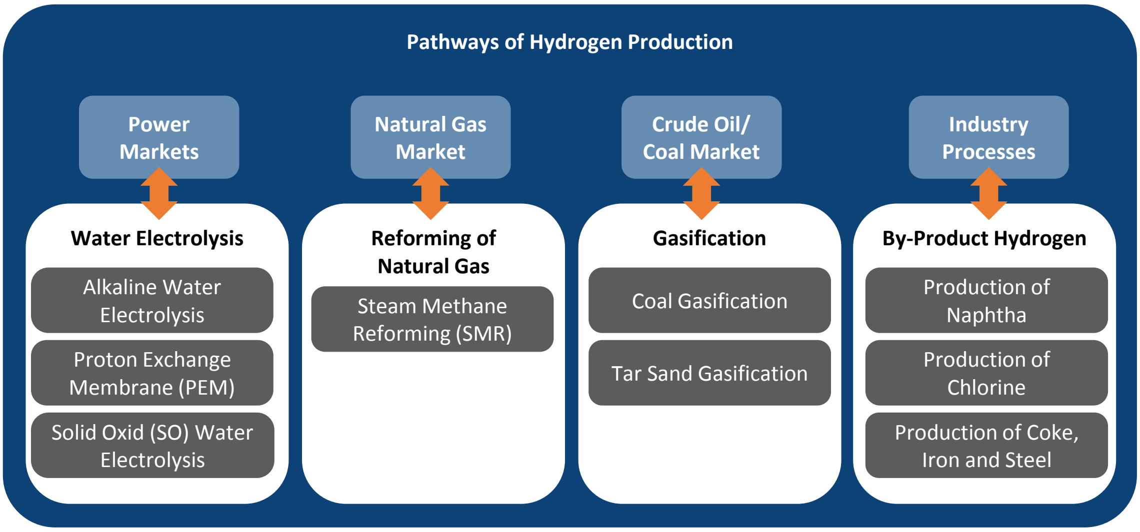


Figure 11: Pathways of hydrogen production

Currently, most of the hydrogen demand worldwide is covered by hydrogen production via SMR. In 2014, its share accounted for around 48 % of total hydrogen production. Around 30 % are generated during petroleum refining process, 18 % is produced from coal and less than 5 % are produced by other means (see Figure 12) [22]. By 2014, the worldwide generation capacity of water electrolysis was around 8 GW [23]. Within Germany, in 2015 around 90 % of hydrogen demand was produced by processing of hydrocarbons (natural gas, crude oil and coal) and approximately 9 % via chlorine-alkaline electrolysis. Less than 1 % of the total hydrogen demand was produced by water electrolysis [24].

Due to the high demand of hydrogen within many industrial processes, large amounts of by-product hydrogen are directly used on site or on adjacent sites. Since the refinery industry shows a large hydrogen demand for processes like hydro-treating, hydro-cracking and desulphurisation, the hydrogen generation during catalytic reforming of naphtha usually only meets a portion of the hydrogen demand. Additionally, due to increased SO_x regulations, the trend towards refining heavier crude as well as a falling demand for heavy end-products, crude refineries increasingly show a net deficit of hydrogen. Currently, this net demand is mainly supplied by large on site SMR units [23].

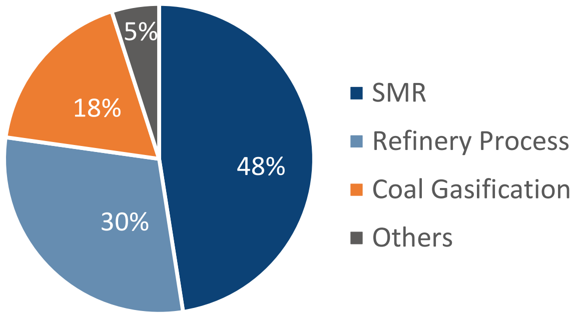


Figure 12: Worldwide share of hydrogen production pathways in 2014 [22]

Within steel industry, by-product hydrogen is currently mainly used for meeting thermal requirements on site resulting in an increased overall energy efficiency. Generally, the generated hydrogen could also be used for other purposes, however due to low hydrogen purities many industry purposes would require extensive purification [22].

Since chlor-alkali electrolysers are usually located at large sites of chemical industry, its by-product hydrogen is also used on site e.g. for combustion purposes in order to produce steam or in chemical reactions with hydrogen demand. Access hydrogen is sold to distributers or gas companies [25].

Captive and merchant hydrogen

As shown above, the hydrogen demand is mainly generated by only a few, large industrial customers. Therefore, most of the consumed hydrogen is generated on site. This so called captive hydrogen includes both by-product hydrogen that is used for other industrial processes at the same site and on-purpose hydrogen production by SMR units and water electrolysers that generate hydrogen solely in order to supply this industrial site. Within Europe, the share of by-product hydrogen accounts for approximately 35 % of captive hydrogen.

A rather small amount of hydrogen is considered as merchant hydrogen. Merchant hydrogen is used to supply large industry customers by industrial gas producers and usually consist of amounts of access by-product hydrogen and hydrogen generated by other means, e.g. via SMR. While the amount of merchant hydrogen is still rather small compared to captive hydrogen, over the past years the share of merchant hydrogen has been steadily increasing to 12 % in 2011 and estimations indicate a share of 16 % in 2016 due to an increasing hydrogen demand [23].

Green Hydrogen

Taking into account European decarbonisation goals in terms of mobility, industry, heating and energy supply, a low greenhouse gas (GHG) emission impact is essential for future production and use of hydrogen. In order to additionally facilitate sustainability of hydrogen production, especially hydrogen production based on renewable energy sources is necessary. This renewably generated or “green” hydrogen shows the potential of GHG emission reduction for various sectors:

- ***Industry Sector***: Replacement of existing hydrogen supply currently covered by conventional hydrogen production e.g. SMR of natural gas within the current merchant hydrogen market by green hydrogen.
- ***Mobility Sector***: Substitution of ICE vehicles based on conventional fuels by FCEV fuelled by green hydrogen.
- ***Electric Power System***: Use and storage of green hydrogen for electrification purposes substituting electric power generation by fossil or nuclear fuelled power plants.
- ***Natural Gas System***: Use of green hydrogen or green, synthetic methane within the natural gas system substituting natural gas.

A detailed analysis on the current regulatory framework, general requirements and definition of green hydrogen classification has been widely covered by CertifHy project [26] [27] [28]. In order to classify hydrogen produced via water electrolysis as green hydrogen, it is necessary to ensure that the electric energy consumed by the electrolyser is generated by renewable energy sources such as wind power or photovoltaic power plants. This can be achieved by guarantees of origin (GoO) which assure that one MWh of electric energy has been produced from renewable energy sources and can be traded within Europe.

3.1.6 Hydrogen Prices

The main part of the revenues of an electrolyser originates in the sales of hydrogen to customers, i.e. mobility or industry clients [21]. Consequently, the economic efficiency of electrolyser business models is highly dependent on the hydrogen prices that the hydrogen end-users are willing to pay. These hydrogen prices are not only highly dependent on the type of end-user, but also on other factors such as the location of the end-user respectively hydrogen production.

Mobility Sector

In order to estimate future competitive hydrogen prices for FCEV, other studies investigate a comparison of FCEV with vehicles with an internal combustion engine (ICE). Based on an estimated efficiency of both vehicles as well as future estimations on gasoline or diesel prices, maximal permissible hydrogen production costs can be calculated so that FCEV are competitive compared to ICE. For example, with an assumption of a gasoline price of 1.22 €/l, an ICE efficiency of 4.12 l/100km and a FCEV efficiency of 0.54 kg/100km the maximum permissible hydrogen production costs would be 9.31 €/kg in order to be competitive [29]. For different studies, the results of this method are shown in Figure 13 (Schiebahn et al. [19], German Aerospace Center et al. – DLR [29], BEE Platform System Transformation [30] and Ludwig-Bölkow-Systemtechnik – LBS [31]).

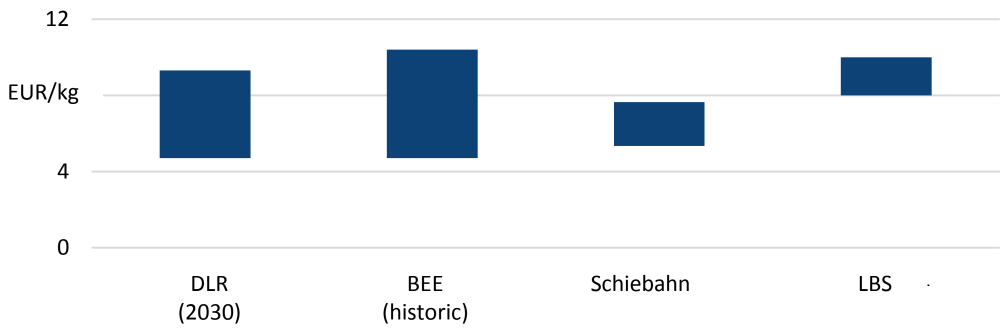


Figure 13: Maximal permissible hydrogen costs for competitiveness with ICE [19] [29] [30] [31]

It can be seen that hydrogen production costs by water electrolysers should not be larger than around 8-10 €/kg. In case the hydrogen needs to be transported from the location of the electrolyser to hydrogen refuelling stations, additional transportation costs need to be taken into account. As a result, the maximal permissible hydrogen production costs would need to be lower than 8-10 €/kg. Consequently, the Fuel Cells and Hydrogen Joint Undertaking Multi-Annual Work Plan 2020 also sets a target of 5.0-9.0 €/kg in terms of hydrogen delivered to hydrogen refuelling stations [32]. Based on the end-user acceptance price, cost and profit margins of the hydrogen refuelling station operator (HRS) need to be taken into account as well. The range of the HRS operator price acceptance usually is around 4-7 €/kg [21] (see Figure 14).

With regard to the European goals of decarbonisation of the mobility sector, it needs to be emphasised, that for hydrogen mobility applications the hydrogen should be renewably generated. Consequently, the hydrogen price acceptance shown above is directed towards "green" hydrogen.

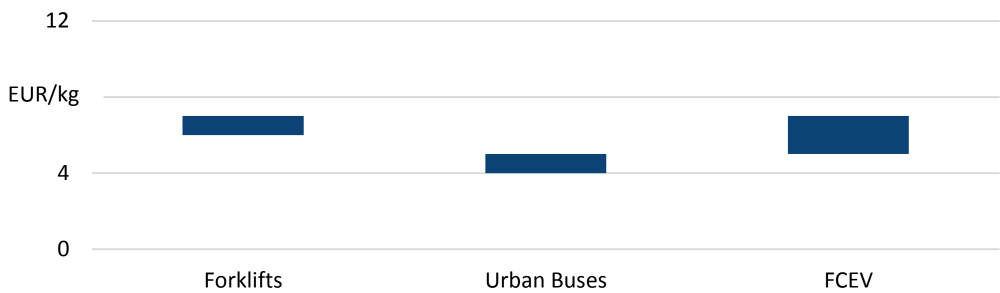


Figure 14: Acceptable hydrogen fuel price delivered to HRS
(selling prince for the power-to-hydrogen system operator) [21]

Industry Sector

For the industry sector, an estimation of hydrogen prices is also difficult to make since the hydrogen market is dominated by only a few large industry actors and the major amount of hydrogen production is classified as captive. In contrast to other transparent market places such as the spot markets for electric energy or natural gas, there is no central market for hydrogen and therefore hydrogen prices are subject to bilateral transactions for merchant hydrogen.

In terms of evaluating future hydrogen prices for industrial applications, a widely used approach is a comparison of the production cost setup for mature hydrogen production pathways. As discussed above, for merchant hydrogen, the main mature production pathway besides by-product hydrogen is SMR of natural gas. Due to its mature technology, hydrogen production costs of SMR units are expected to be mainly dependent on the natural gas price for industrial customers. Depending on different assumptions in terms of future natural gas prices, investment and operational costs of SMR units, the estimations of hydrogen production costs vary in literature. Figure 15 shows the estimation of production costs taking into account CAPEX and OPEX of hydrogen from on-site SMR units estimated by different studies (CertifHy project [17], German Aerospace Center et al. - DLR [29], E4tech et al. [33] and BEE Platform System Transformation [30]). Compared to the other values, the upper limit of the cost estimation by DLR is rather high due to the assumption of a high maximum natural gas price for industrial customers of 94 €/MWh.

As long as SMR units contribute to merchant hydrogen, SMR hydrogen production costs can be considered as being an indicator of minimum hydrogen prices to be expected within a future hydrogen market. The actual hydrogen prices for industrial customers are expected to be higher e.g. due to additional costs for hydrogen transportation and profit margins.

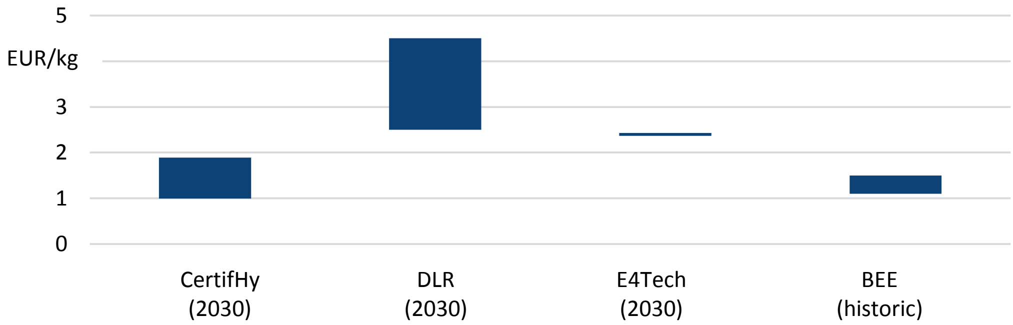


Figure 15: Production Costs of Hydrogen from on-site SMR [17] [29] [33] [30]

Natural Gas System

In case hydrogen is fed into the natural gas system, it is easier to estimate a potential price. In this case, estimations can be made based on the development of the spot market price of natural gas. In case of injecting hydrogen directly into the natural gas system (blending), a corresponding hydrogen price can be estimated by considering the lower heating value of hydrogen (33.33 kWh/kg). With a natural gas price of 25 €/MWh (35 €/MWh), a hydrogen price of maximum 0.8 €/kg (1.1 €/kg) would be expected. As mentioned above, it needs to be emphasised that blending might be restricted due to maximum volume fractions of hydrogen within the natural gas system. These restrictions can be avoided by means of an additional methanation process in order to convert the hydrogen generated by the water electrolyser into methane. However, due to conversion losses of approximately 70 % to 90 %, the price would drop to 0.58 €/kg to 0.75 €/kg.

Taking into account the decarbonisation goals of the European Union, it can be envisaged, that hydrogen classified as being "green" might achieve higher natural gas prices than the spot market price of natural gas. Analogous to current feed-in tariff schemes of bio methane, green hydrogen injection tariffs could support electrolyser business models directed towards natural gas system in order to aid decarbonisation goals. While currently no regulatory framework exists within Europe, potential feed-in tariffs for green hydrogen between 1.3-5.5 €/kg (depending on country) could be achieved [21].

Impact of End-User and Electrolyser Location

For several potential end users of hydrogen, production and consumption of hydrogen does not necessarily take place at the same location. This often occurs when the hydrogen demand of the end-user is not large enough to operate an on-site SMR hydrogen production facility economically efficiently (e.g. for smaller industrial hydrogen end-users). In case of this central, off-site hydrogen production, distribution and compression of hydrogen needs to be taken into account in order to assess the hydrogen price that is acceptable for end-users. The distribution and compression of hydrogen entails additional costs for filling centres and compressor skids as well as costs for hydrogen transport. These costs are highly dependent on the location of both hydrogen production facility and hydrogen end-user. A detailed analysis and estimations of the additional costs due to off-site hydrogen production can be found in [21], [31] and [33]. Consequently, these additional costs lead to a higher hydrogen price acceptance of the hydrogen end-user.

Interim Conclusion

Figure 16 shows a summary of the expected hydrogen price ranges for different sectors based on the analysis above. Highest hydrogen prices can be expected within the mobility sector. Due to competition by SMR hydrogen production the expected hydrogen prices for industrial end-users are significantly lower. The lowest hydrogen prices can be expected for hydrogen or synthetic methane injection into the natural gas system. However, in case of potential future recognition of green hydrogen injection in terms of specific feed-in tariffs, higher hydrogen prices can be expected. Consequently, it can be expected that business models directed towards the mobility sector are especially promising.

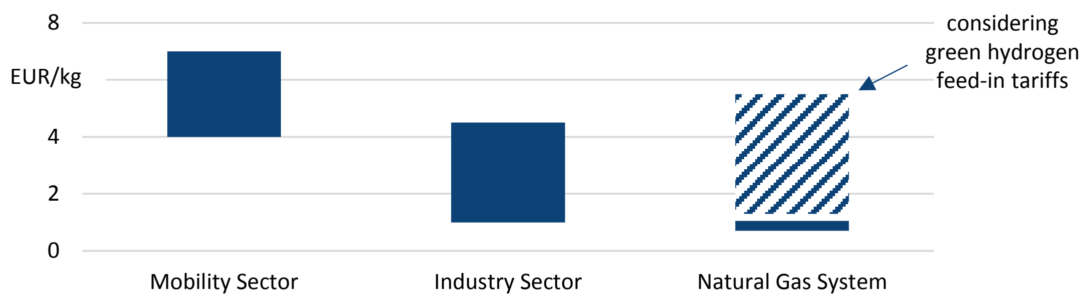


Figure 16: Summary of expected hydrogen prices for different sectors

As off-site hydrogen production results in additional costs due to distribution and compression of hydrogen, electrolyser installations should be located within the vicinity of the hydrogen end-user. On the other hand, it can be expected that in case alternative hydrogen production facilities such as SMR hydrogen production are located far away from the hydrogen end-user, hydrogen price acceptance of this "remote" end-user is higher than if the alternative hydrogen production facility was located on-site or within the vicinity of the end-user. In terms of economic efficiency of electrolyser business model, electrolyser operation within the vicinity of "remote" hydrogen end-users is especially promising.

3.1.7 Alkaline Water Electrolyser CAPEX and OPEX

In order to assess the economic efficiency of electrolyser business models, it is necessary to take into account investment and operational costs. While a detailed cost-breakdown of the

ELYntegration multi-megawatt high pressure alkaline water electrolyser will be conducted through a thorough life-cycle cost analysis in later stages of the project, only a very brief discussion on the electrolyser cost structure is given within this deliverable.

The total costs of an electrolyser project can be separated into electrolyser system costs (stack, separators, transformers, rectifier, lye system and water management), costs for additional equipment for hydrogen storage and transport systems (filling centres, compressor skids, storage systems) and other costs. These other costs include civil works costs, engineering costs as well as costs for the control system, the interconnection, commissioning and start-up of the electrolyser. A detailed analysis of these cost components for an alkaline electrolyser can be found in [33] and [21]. A general overview of the estimated development of CAPEX and OPEX of these cost components is summarized in the appendix (9.4). An overview of economic data used for the evaluation of business models for a 10 MW alkaline water electrolyser is given in chapter 4.2.2.

3.2 Overview of Relevant Electrolyser Business Models

Focus of this deliverable is the investigation of potential future electrolyser business models in the context of a changing European power system towards higher shares of renewable energies and highly dynamic electrolyser capabilities. Consequently, in this study, the classic business model of cross-commodity arbitrage trading between the spot market and the hydrogen market is expanded by a consideration of the provision of control reserve by electrolysers.

For this case of study, it is taken into account that within the ELYntegration project a flexible alkaline water electrolyser operation was tested technically feasible so that the unit may theoretically enable a participation in the reserve markets for Frequency Containment Reserve (FCR), automatic Frequency Restoration Reserve (aFRR) and manual Frequency Restoration Reserve (mFRR). As the final design of the electrolyser of the project is aimed at a capacity of 10 MW, it is considered big enough to participate in reserve markets without pooling.

Even though regulatory decisions which allow for electrolysers to participate in all reserve markets in Europe are yet to be passed, possible revenues for electrolysers are assessed for Germany at all reserve markets within this study. This is done in order to have an idea of possible future revenues for weighting marketing opportunities for flexible electrolyser dispatch with the increased investment costs for flexible units.

3.2.1 Main Operational Strategies

Four operational strategies for electrolysers are possible when considering cross-commodity arbitrage trading as well as reserve market participation. Those strategies are depicted in Figure 17.

For **cross-commodity arbitrage** trading the electrolyser is used when the spot market price is low and thus the spread between procurement and the sale price for hydrogen is high enough to cover conversion losses of the electrolyser. Revenues may be achieved if the spread is higher than the conversion losses.

For the provision of **FCR**, the electrolyser would have to be synchronised with the grid for the entire time of the tender, which is currently one week in Germany. With the symmetric bid for FCR an electrolyser is required to be able to provide negative and positive reserve power at all times. This means that the unit is operating at a point where it may ramp down to minimum load for providing positive reserve power or maximally ramp up to nominal capacity for providing negative reserve power. The bid for FCR is symmetric with steps of 1 MW, which means that considering a 10 MW electrolyser with 15 % minimal load, +/- 4 MW FCR may be offered into the market. This operation is shown in Figure 17. The market price for FCR is paid for the provision of control power, the actual retrieval of reserve power is solidary and thus not compensated. If a bid is accepted, the unit has to stay synchronised to the grid for the entire tender of one week. Because the bid is symmetric, the operating point would in this case be at 5.5 MW which gives the ability to ramp the load up and down 4 MW thus being able to provide the total amount of FCR at all times. Because of the continuous operation, the units would have to procure the electricity for the operational point (4.5 MWh/h) at the spot market.

Frequency Restoration Reserve can be offered as **positive or negative** power and as automatic and manual Frequency Restoration Reserve (aFRR and mFRR). The difference between the two types of reserve is essentially by means of their respective activation times of 5 minutes and 15 minutes. The minimum tender for FRR in Germany is set at 5 MW. For the 10 MW ELYntegration electrolyser, feasibility of technical requirements in terms of flexibility and size is given for providing both types of FRR. For an electrolyser, the provision of negative FRR implies a synchronisation to the grid with at least minimum power with additional 5 MW reserve for providing reserve power. Providing positive FRR implies a synchronisation to the grid at a load of minimum power plus provided positive FRR, so that a reduction of the electrolyser load at retrieval of reserve power decreases the load in the grid. In both cases of FRR provision, the dispatch of the other available 3.5 MW may be optimized at the spot market considering cross-commodity arbitrage trading.

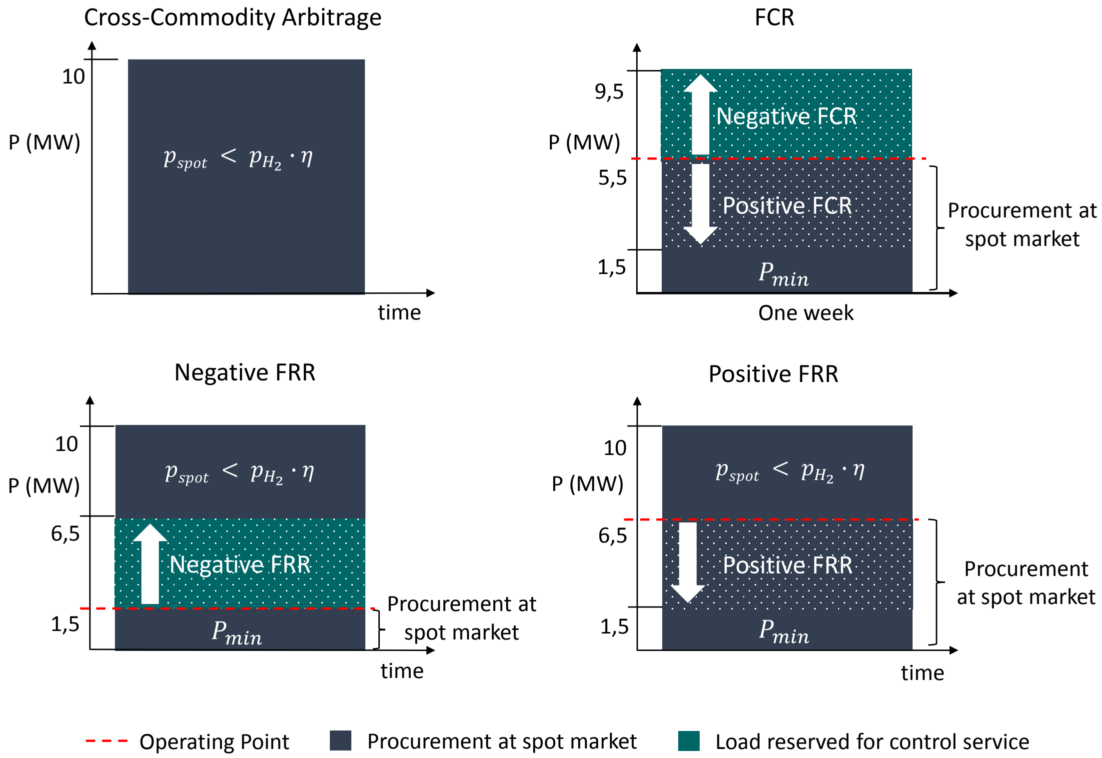


Figure 17: Operational Strategies for Electrolysers at Different Markets

3.2.2 Potential Business Models

Seven different business models of cross-commodity arbitrage trading and reserve market participation will be assessed within this study. The aim is to provide an analysis of possible net margins from the different possible operational strategies from the participation at different reserve markets and new applications in terms of grid services as part of the TSO grid congestion relieving process.

As shown in chapter 3.1.6, especially for the mobility sector high hydrogen prices can be expected. Therefore, a scenario of green hydrogen production to be sold to hydrogen refuelling stations for mobility applications is considered. Since the hourly hydrogen production of a multi-megawatt electrolyser would be enough to fully refuel several hundred fuel cell electric vehicles, it is assumed that the hydrogen is produced off-site the hydrogen refuelling station.

The following business models will be evaluated:

BM 1: Cross-Commodity Arbitrage Trading

For Cross-Commodity Arbitrage Trading, the electrolyser is used when the spot market price is low and thus the spread between procurement and the sale price for hydrogen is high enough to cover conversion losses of the electrolyser. Revenues may be achieved if the spread is higher than the conversion losses. For that analysis, spot price time series as well as hydrogen prices are required.

BM 2: FCR Provision

FCR provision with a 10 MW electrolyser providing 4 MW of symmetric FCR and running 5.5 MW power is assessed. For that, hydrogen, electricity spot market and FCR price time series are required. If electricity spot prices are low, the free capacity can be additionally used for cross-commodity arbitrage trading.

BM 3: Positive aFRR Provision

5 MW of positive aFRR may be provided by an electrolyser by running at 6.5 MW and declining its load upon demand. If electricity spot prices are low, the free capacity can be additionally used for cross-commodity arbitrage trading. Currently in Germany, minimum tenders are one week, but are expected to decrease to 4 hours. This may lead to a decline of currently high prices in Germany because more competition from more participants in the market may develop.

BM 4: Negative aFRR Provision

5 MW of negative aFRR may be provided by an electrolyser by running on minimal load (1.5 MW) and ramping its load up upon demand. If electricity spot prices are low, the free capacity can be additionally used for cross-commodity arbitrage trading. Like for positive aFRR, minimum tenders are one week, but are expected to decrease to 4 hours.

BM 5: Positive mFRR Provision

For providing 5 MW pf positive mFRR, the same operational strategy applies as for positive aFRR. The difference between the two markets are shorter tenders of 4 hours and less flexible technical requirements, which leads to lower prices due to more competitors.

BM 6: Negative mFRR Provision

Equally, for the provision of 5 MW of negative mFRR, the same operational strategy applies as for negative aFRR but with market design characteristics described for the positive mFRR.

BM 7: Optimized Unit Commitment

The optimized unit commitment of electrolysers takes not only one control reserve into account, but all reserve qualities under consideration of tender durations as well as cross-commodity arbitrage trading. In a first step, it is analysed whether it is more profitable to apply cross-commodity arbitrage trading or participate in the control reserve market during the time of the shortest tender, which is 4 hours, and the business model with the highest revenue is selected for the 4 hours. This is done for comparing the spot market and FRR. In the next step, revenues from FCR provision for the tender duration of one week are compared to revenues resulting from optimized dispatch between FRR and the spot market. This results in the selection of the most profitable reserve markets or the spot market. The freely available capacity, which differs between the business models, is optimized for cross-commodity arbitrage in every hour.

BM 8: Provision of Grid Service to TSO

The electrolyser is solely operated as shiftable load that increases its consumption during times of curtailment of RES within the transmission grid thus reducing the amount of necessary curtailment in order to remove congestions within the transmission grid.

BM 9: Cross-Commodity Arbitrage Trading and Provision of Grid Service to TSO

Within this business model, the electrolyser operates at the spot market performing cross-commodity arbitrage trading like in BM 1. In case the electrolyser is not in operation based on spot market participation, it may offer flexibility in terms of a shiftable load for redispatch purposes as in BM 8.

4 METHODOLOGY

To evaluate the different business opportunities for electrolysers in the current market situation as well as in the future, costs, revenues and resulting net margins are calculated for different scenarios for years 2014, 2024 and 2034. Potential benefits from participation in the spot market, the control reserve market and the provision of grid services (redispatch process of transmission grid operators) are assessed. The evaluation methodology as well as input parameters are presented in the following chapter. The focus of the study is set on the influence of changing market environments of electricity market and the electricity grid integration of the electrolyser, thus detailed electricity spot and control reserve market simulations as well as grid simulations are conducted to evaluate future potentials in the context of the transition of the electricity market towards green energy. The simulation approaches for electricity market, control reserve market and transmission grid simulations are explained in detail in the appendix in chapters 9.1 and 9.2.

4.1 Business Model Evaluation

The evaluation of new potential business models for electrolysers is done by an estimation of future net margins (see Figure 18). Based on the calculation of operational costs (e.g. due to the electric energy purchase) and the investment costs for the electrolyser (e.g. costs for the stack) on the one hand, and future revenues from the sales of the generated hydrogen and potential reimbursement for the provision of system or grid services, yearly net margins can be derived. It needs to be mentioned that a detailed investigation of investment costs is not subject of this study. They will be investigated in detail during later stages of the ELYntegration project performing an in-depth life-cycle cost analysis.

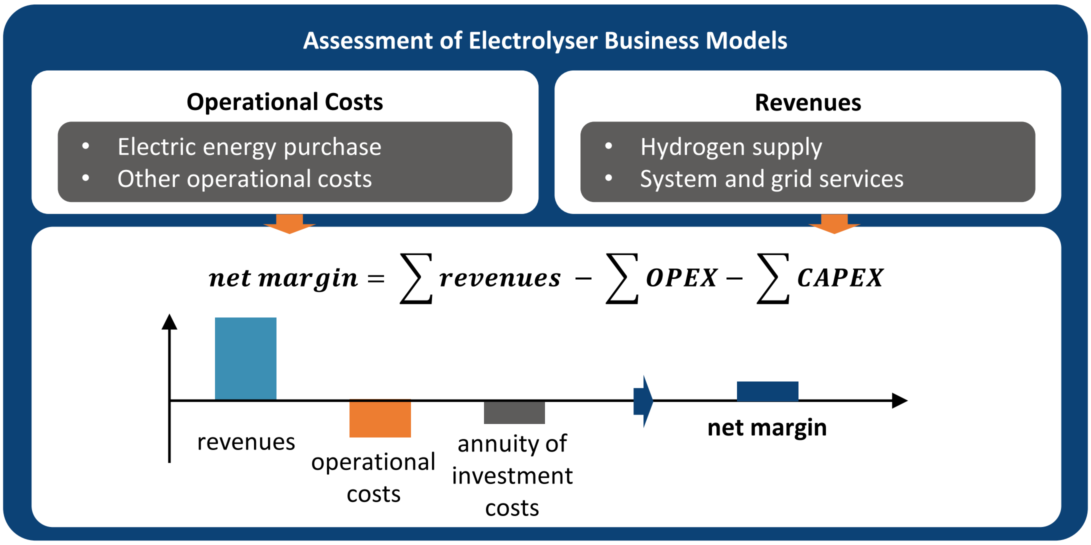


Figure 18: Assessment of electrolyser business models by calculation of net margins

As mentioned in chapter 3.2.2, within this study, a business model scenario of green hydrogen production to be sold to hydrogen refuelling stations (HRS) for mobility applications is considered. Consequently, a complete cost break-down of a corresponding business case would not only include the costs that arise on-site the electrolyser, but also operational and investment costs for the transportation of the generated hydrogen from the electrolyser location to the HRS location. These costs correlate with the distance between both locations. Therefore, the economic efficiency of a business case is dependent on the specific location of the electrolyser and HRS units.

Since the aim of this deliverable however is the identification of general business opportunities within future electricity markets and not the identification of specific electrolyser locations within each country, in the following, the business model evaluation does not include costs for hydrogen transport within the calculation of net margins. For the identification of specific business cases (later stage of the project), this net margin can be used as input data as it defines a maximum permissible amount of location dependent electrolyser project costs that still leads to a profitable electrolyser business case.

In order to evaluate future operational costs and revenues of each of the business models, different fundamental simulation methods are used (see Figure 19). For the calculation of operational costs and revenues, price time series for the spot market and the five different reserve markets are required. These are calculated using market simulation models for the spot market as well as the control reserve markets. Based on these price time series and estimated future hydrogen prices, trading at the spot and control reserve markets and corresponding net margins for business model 1 to 7 can be derived. In terms of hydrogen price estimates, it is assumed that these are constant within one year.

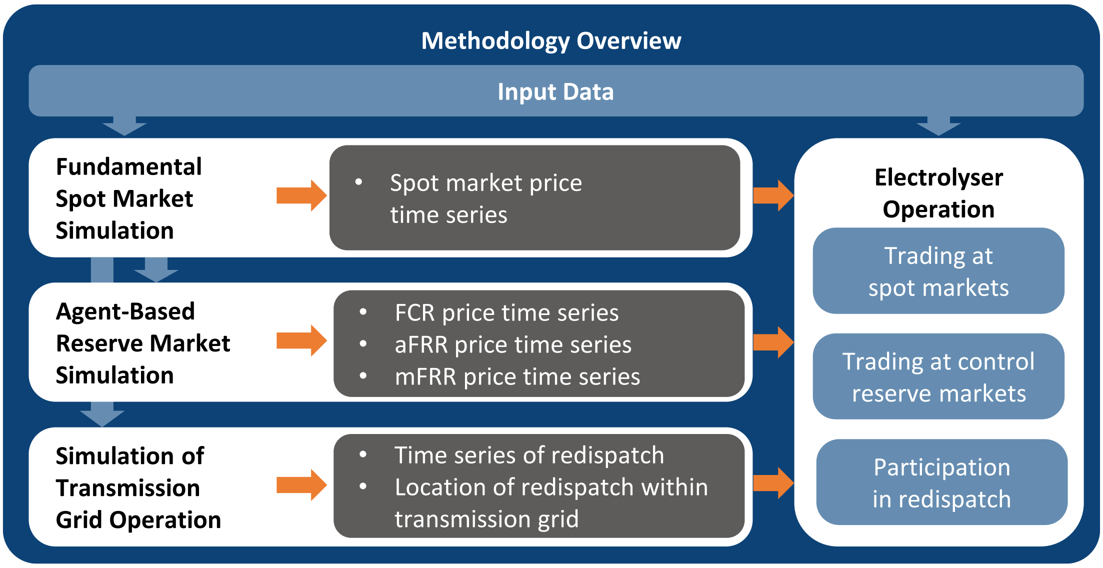


Figure 19: Overview of methodology for business model evaluation

Business model 8 and 9 are directed towards electrolyser participation in the congestion relieving process of transmission grid operators (TSO). Due to the TSO process described in chapter 3.1.4, the evaluation of these business models requires to take into account remedial measures of TSO, including both network related measures and market related measures. Within this study, a corresponding fundamental approach for a transmission grid simulation including a redispatch model is used that utilizes the market based dispatch of conventional power plants from the spot market simulation as an input parameter.

The required input data for the simulation tools is portrayed in Figure 20. A detailed explanation of the generation system and transmission system scenarios for the examined years within this study is given in the following chapter.

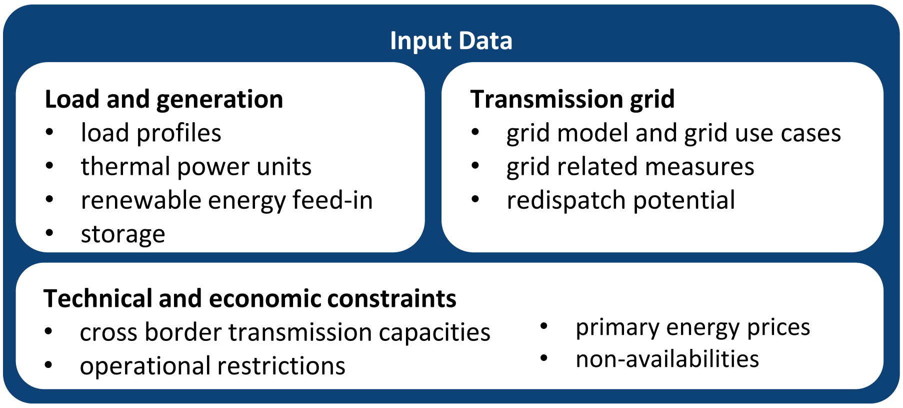


Figure 20: Input data for market and transmission grid simulation methods

4.2 Input Parameters

4.2.1 Market and Transmission Grid Simulation

Spot Market Simulation

The spot and control reserve market price simulations are conducted based on the following input parameters. For the year 2014, historic information concerning the generation fleet, commercial exchanges between market areas, primary energy prices and CO_2 emission certificate prices as well as historic weather time series were used for the calculation of spot market and reserve market prices. The 2024 scenario is based on the grid expansion plan (German: Netzentwicklungsplan, NEP) Scenario B for 2025 [34] for Germany with additional consideration of the renewable energy law in Germany (EEG 2017) and on European Mid-Term Adequacy Forecast (MAF) Scenario B for 2024 [35]. Those scenarios represent a best guess for the development of the market in the near future. To assess consequences of a green transition which may represent as suitable environment for electrolysers, the farther future of 2034 is based on the System Outlook and Adequacy Forecast (SOAF) [36] Vision 3 for Europe and the NEP 2034 for Germany. The visions also include estimations on future primary energy prices as well as CO_2 emission certificate prices.

Spot market price time series are calculated for all European countries, thus providing information on possible cross-commodity arbitrage trading revenues in different European countries. Spot market price time series are used for the assessment of cross-commodity arbitrage trading for different European countries for years 2014, 2024 and 2034. Furthermore, the reserve market is simulated. For reserve market price time series, it has to be noticed that prices of reserve markets are highly dependent on market participant bidding behaviour and the market design. Due to this particularity, prices for reserve markets are calculated only for Germany, because the model used for the simulation incorporates the current and probable future market design and bidding strategies in Germany. Therefore, business models 2 to 7 are calculated for Germany for 2014, 2024 and 2034.

Transmission Grid Simulation

Business model 8 and 9 include electrolyser participation within the congestion relieving process of transmission grid operators. For these business models, results are presented based on transmission grid simulations for Germany. Germany is selected as an example, since here, redispatch plays a significant role within the congestion management of transmission grid operators. Additionally, German legislation already mentions the possibility of a future introduction of a flexibility provision in terms of load increase such as start-up of electrolysers to the congestion relieving process on transmission grid level. The simulations are undertaken for years 2014 and 2024. The transmission grid model for year 2014 is developed based on publicly available information [37]. For 2024, the transmission grid model is derived from scenario B1 2025 GI of the German grid development plan NEP 2025 [38], the German offshore grid development plan O-NEP 2025 [39] and from the ENTSO-E network development plan TYNDP 2016 [40] for the ENTSO-E area. The allocation of conventional power plants is based on [41, 42] and the geographic distribution of RES power plants is based on [43, 44]. The corresponding transmission grid models as well as the allocation of power plants within Germany for 2014 and 2024 are shown in Figure 41 and Figure 42 of the appendix. For scenarios with a longer time horizon than year 2024, it is expected that the significance of redispatch within Germany gradually decreases due to the advancing grid expansion. Therefore, this deliverable refrains from examining business model 8 and 9 for later years.

4.2.2 Business Model Evaluation

Market Overview

For the business model evaluation, some assumptions for the market environment have to be made based on the analyses in chapter 3. Those assumptions are listed in Table 1. Based on the hydrogen price analysis for mobility applications in chapter 3.1.6, the hydrogen price to be gained when selling hydrogen to HRS operators is assumed to be 6 €/kg. These values remain unchanged for all scenarios considered within this deliverable. A sensitivity analysis in terms of different hydrogen prices is presented in deliverable 6.4 of the ELYntegration project [45]. The cost of supply, which consists of cost for electricity market access and aggregator fees etc. is calculated based on the costs for energy and supply in chapter 3.1.2. It is a calculated rounded average of the difference between costs of energy and supply for large industrial consumers and mean wholesale market prices for the considered countries. For taxes, levies and grid fees, exemptions are assumed for all countries and time horizons. Green certificates are considered to cost 0.4 €/MWh [21]. Electricity and control reserve prices are taken from the market simulations described in the following chapter 5.

Table 1: Key Assumptions for business model evaluation

Key Indicator	Unit	2014	2024	2034
Hydrogen Price	€/kg_{H2}	6.0	6.0	6.0
Costs of Supply	€/MWh	30.0	30.0	30.0
Taxes and Levies	€/MWh	exempted	exempted	exempted
Grid Fees	€/MWh	exempted	exempted	exempted
Green Certificates	€/MWh	0.4	0.4	0.4
Electricity Prices	Based on Market Simulations			
Control Reserve Prices				

Electrolyser Key Performance Indicators and Economic Data

For the evaluation of future business models within this deliverable, the electrolyser key performance indicators (KPI) presented in Table 2 are used. These values are based on the analysis of the electrolyser cost structure in chapter 3.1.7. Here, data of [21] and [33] is projected and applied for a 10 MW alkaline water electrolyser. The CAPEX considered in the following includes the electrolyser system ($CAPEX_{ely}$), the hydrogen storage units ($CAPEXH_{H2\ storage}$), filling centres ($CAPEX_{filling\ centre}$) for the physical interface with the hydrogen logistical system and other investment costs ($CAPEX_{other\ costs}$). These other investment costs include civil costs and non-equipment costs (engineering costs, costs for the distributed control system and energy management unit, interconnection costs, costs for commissioning and start-up costs) [21]. Apart from operational costs due to electricity purchase and efficiency losses, electrolyser system costs for maintenance, spare parts and replacement of the auxiliary components ($OPEX_{ely}$) as well as other costs for the operation of the facility ($OPEX_{other\ costs}$) is taken into account [21].

The storage size is calculated based on downtimes of the electrolyser as shown in the unit dispatch results. For the dimensioning of the hydrogen storage needed for each business model, it is assumed that the hydrogen storage unit should be dimensioned in such a way that a continuous hydrogen supply at a constant rate per hour can be ensured. Stack replacement costs and system degradation are not considered. For the calculation of annuities, a discount rate of 8% is considered.

Table 2: Assumed key performance indicators for the evaluation of business models of a 10 MW alkaline water electrolyser project

Key Performance Indicator	Unit	2014	2024	2034
Power Consumption	kWh_{el}/kg_{H2}	53.2	51.2	49.2
Output Pressure	bar	30	30	30
$CAPEX_{ely}$	k€/MW	990	614	556
$CAPEX_{H2\ storage}$	€/kg	470	470	470
$CAPEX_{filling\ centre}$ 200 kg/h, 30 bar → 200 bar	k€	2699	2699	2699
$CAPEX_{other\ costs}$	$\%(CAPEX_{ely}+CAPEX_{H2\ storage})$	37.5	37.5	37.5
System lifetime	years	20	20	20
$OPEX_{ely}$	$\%CAPEX_{ely}$	2.2	2.2	2.2
$OPEX_{other\ costs}$	$\%CAPEX_{other\ costs}$	4	4	4

5 MARKET AND TRANSMISSION GRID SIMULATION RESULTS

5.1 Spot Market Simulation

The market simulation is conducted for the years 2014, 2024 and 2034 for all European countries. Considered capacities of conventional and nuclear power plants as well as of RES capacities are taken from the above-mentioned sources of SOAF, MAF and NEP [46, 35, 34]. Furthermore, exchange capacities, load as well as primary energy prices are taken from the scenarios. An overview of calculation results in terms of generation for the three simulated years is shown in the Appendix in Figure 38, Figure 39 and Figure 40. Figure 21 shows the considered countries with their respective installed conventional power units exemplarily for 2034.

A backtesting of the 2014 calculation with historic prices of 2014 shows that the calculated mean prices match historic prices well. For Germany, the model results in an average spot market price of 30.73 €/MWh, compared to 32.73 €/MWh historically. Calculated prices for 2014 can be seen in Figure 22. The backtesting shows that the simulation results underestimate historic prices slightly. A reason for that is that the fundamental market simulation calculates market prices based on fundamental costs with perfect foresight, leaving out market inefficiencies coming from imperfect information which in reality influence market participants, unit commitments and exploitation of available capacities for generation and transmission. For the business model evaluation, which is conducted in the following, this means that results present a lower limit of possible net margins, because low prices favour electrolysers as consumers. The backtesting also shows that negative spot market prices that occur in historic situations of very low residual demand are not adequately calculated with the market simulation approach. This is because negative prices are not based fundamentally on margin generation costs but are mainly due to RES feed-in priorities that are based on regulatory decisions and thus are not market-based.

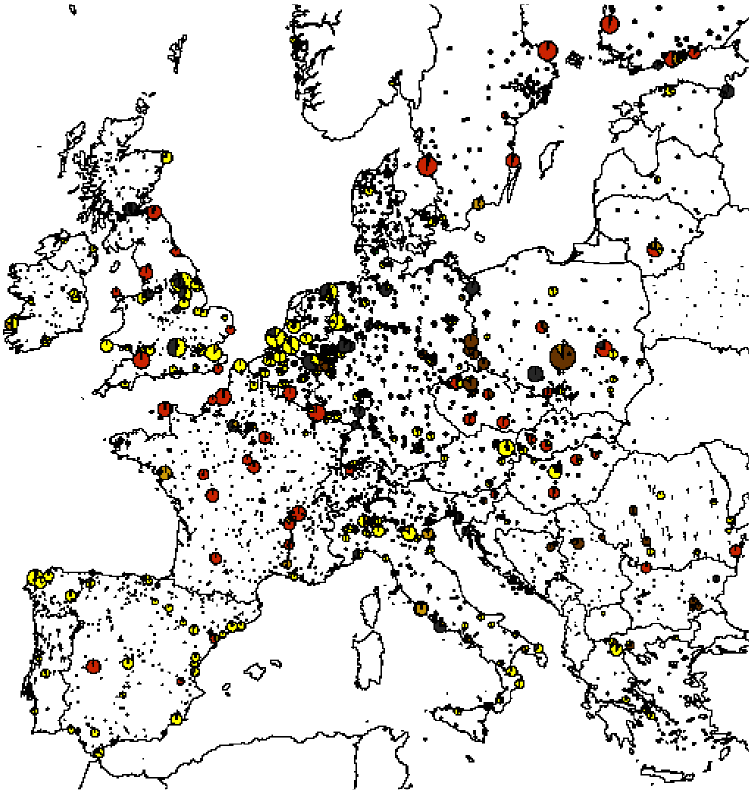


Figure 21: Conventional Generation Units in 2034 in Europe

The average base and peak prices for the spot market that are calculated for the years 2014, 2024 and 2034 are depicted for different European countries in Figure 22. Because of rising RES shares within generation systems, the conventional definitions for peak and off-peak times are no longer conclusive. Those were historically based upon low load at night-time (off-peak hours) and thus low prices and on high load during day-time (peak hours). Because prices do not follow the daily load time series but are mainly influenced by fluctuating RES infeed, the peak price is for this evaluation defined mathematically as the 90 %-quantile of the highest prices of the year. The base price in defined as the 10 %-quantile, representing the lowest prices of the year.

Looking at the development of average spot prices for 2014, 2024 and 2034 in Figure 22, a trend of rising average spot market prices can be observed. The spot price depends on multiple influences. One main impact on the price development here are rising primary energy and CO_2 emission certificate prices that are embedded within the scenarios. Further impacts on market prices are load, power exchanges between different market areas, the composition of the power plant fleet and RES shares. In the 2034 scenario, the share of RES in generation is 52 % in Spain (ES), 52 % in the Netherlands (NL), 19 % in the Czech Republic (CZ), 60 % in Germany (DE), 38 % in France (FR), 60 % in Portugal (PT) and 73 % in Austria (AT). Detailed information about the shares of generation are presented in the Appendix. The trend of rising average spot prices can be observed in all countries in Europe, e.g. in Germany from 31 €/MWh (2014) to 38 €/MWh (2024) to 40 €/MWh (2034) or in Spain from 35 €/MWh (2014) to 40 €/MWh (2024) to 50 €/MWh (2034).

Also noticeable is the increasing spread between peak and base prices in future scenarios within the respective year. Especially the 2034 calculation shows a high spread, which can be explained by the high volatility of residual load and thus of spot market prices due to high shares of RES. High shares of fluctuating RES generation result in a residual load that spans between negative values and maximum load. In times of low RES feed-in, future high electricity prices indicate scarcity of available generation capacity. In times of high RES feed-in, the generation exceeds the load. This results in price peaks in both directions, high and low, which explains the large spread between the quantiles.

In countries where the overall RES shares are lower than in other countries, the spreads between base and peak prices are lower in future scenarios compared to those countries with high RES shares. This is for example the case for France. Available transmission capacities between different market areas on the other hand may result in high spreads and high price volatilities even for countries with higher shares of conventional generation units when countries with high RES shares are neighbouring. This can be seen for the Czech Republic.

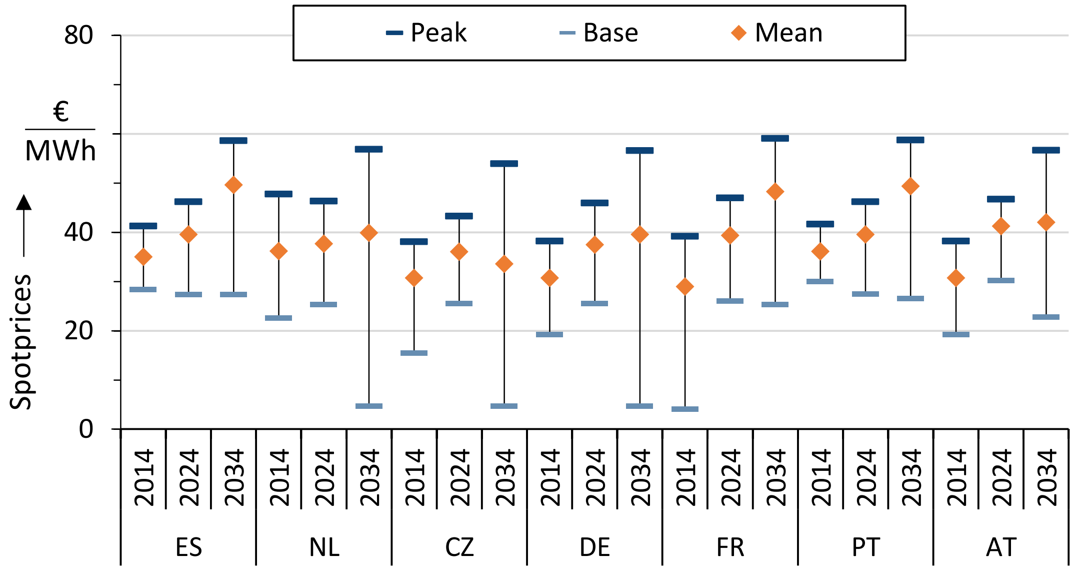


Figure 22: Simulation Results on Electricity Spot Market Prices in Europe

Figure 23 shows the yearly average prices for CO_2 emission certificates, natural gas and electricity prices. Primary energy prices are taken from NEP 2024 and MAF [35, 34]. Natural gas prices are predicted to rise from around 26.2 €/MWh in 2014 to 35 €/MWh in 2034 and CO_2 emission certificates are predicted to rise from 6 €/MWh to 28 €/MWh in 2034. Rising primary energy prices lead to rising electricity prices and would lead to rising hydrogen prices from conventional sources such as SMR. Electrolyser based hydrogen prices on the other hand are not expected to increase in the future due to higher RES feed-in and economies of scale, thus providing a viable green energy source for mobility and other hydrogen applications.

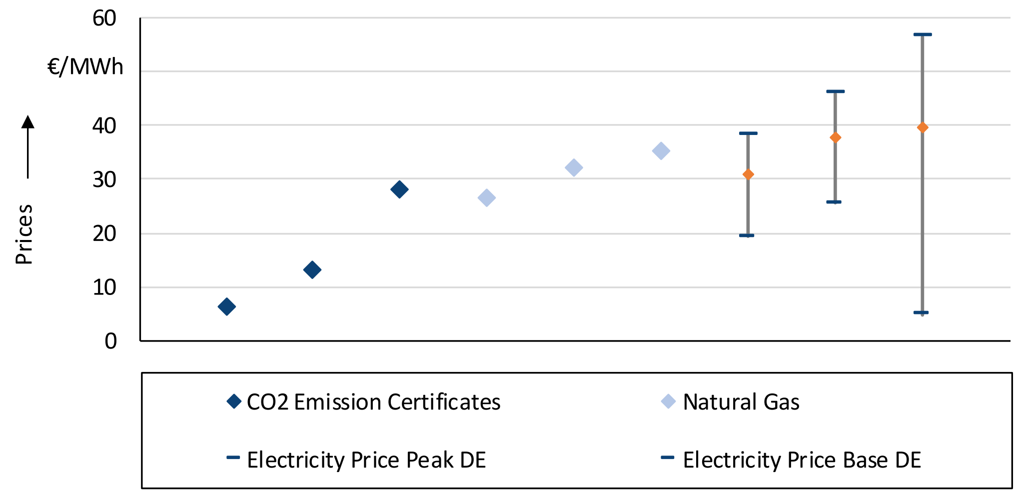


Figure 23: Average Prices for applied Scenarios of CO_2 Emission Certificates and Natural Gas

5.2 Control Reserve Market Simulation

Besides spot market prices, control reserve market prices are calculated for the German market. The average, base and peak prices for those markets for the years 2014, 2024 and 2034 are depicted in Figure 24. As described above, the average spot price in Germany rises from around 32 €/MWh in 2014 to around 37 €/MWh in 2034. Also shown in Figure 24 are the control reserve prices for FCR and positive and negative aFRR and mFRR. Calculated here are the power prices which are paid to committed control units for the reserve of power in case control reserve is called for. The different types of control reserve are analysed in section 3.1.3. As described, the technical requirements for market participation decrease from FCR to aFRR to mFRR. This means that less units are able to provide FCR than aFRR or mFRR. The scarcity of technically feasible units can also be seen within the average prices of the different qualities of control reserve. In 2014, the prices decrease from around 20 €/MW for FCR, 7.0 €/MW for positive aFRR, 3.0 €/MWh for negative aFRR, 4.0 €/MW for positive mFRR and 1.5 €/MW for negative mFRR. A backtesting with historic prices shows that the simulated prices match historic observations. Historic average values for FCR of 20.0 €/MW, positive aFRR of 6.5 €/MW and positive mFRR of 4.0 €/MW are on the same level as simulated results. Prices for positive FRR are higher than for negative FRR. Negative FRR can be provided by all units running above minimal power without additional costs. In that case, high competition and negligible costs lead to these low prices. Prices for positive FRR are higher because technologies typically providing control reserve are generation units. Consequently, compensation for reserve provision must cover at least the marginal generation costs for positive FRR.

For the years 2024 and 2034, simulated FCR prices are the highest prices at the control reserve markets. This is mainly due to the scarcity of available capacities which may serve as FCR control reserve units. This development will most likely increase in future, when none or only a few rotating masses (thermal power plants) that are currently providing FCR are connected to the grid in times of high RES feed-in. The trend has as well been observed in the recent and current market, which leads to investments in battery systems participating in FCR tenders [47]. Those battery systems are already prequalified for FCR provision in Germany. For that reason, higher competition has to be expected in future. This is considered for the calculation of prices for the future scenarios of 2024 and 2034 where additional battery capacities of 300 MW and 2,000 MW respectively were considered as competitors for electrolysers in the FCR market.

For FRR, two other trends can be observed: An inversion of the ratio of prices for negative and positive FRR and the increase of the spread between peak and off-peak prices for control reserve. First, average prices for negative FRR are higher than for positive FRR, in opposition to 2014. With much less conventional generation capacity in the market and days or even weeks with high RES feed-in covering almost the entire load, very few or no conventional power generation units are operating at times. Negative reserve cannot be provided by those units when they are shut down which leads to higher prices. In that context, it must be noted that RES capacities are not providing control reserve within the calculated scenarios. If RES were to participate in reserve markets by 2034, the provision of negative control reserve at minimal cost would be feasible again. Prices for positive FRR on the other hand are decreasing in the future. A reason for that is the higher number of competitors from opening control reserve markets. For aFRR, tenders were reduced from one week in 2014 to 4 hours in 2024, following suggestions by ENTSO-E. This leads to more competition in the aFRR market and thus to declined prices.

As for spot prices, an increase of the spread between base and peak prices can be observed as well for control reserve prices. This is again attributed to rising shares of RES. During times of high RES feed-in, conventional power plants shut down and are not able to provide control reserve, which leads to increasing prices. In the opposite case of low RES shares, enough conventional power plants are available for control reserve provision, which leads to decreasing prices. The combination of those two trends, driven by the fluctuating RES feed-in, attributes for higher spreads between base and peak prices at control reserve markets.

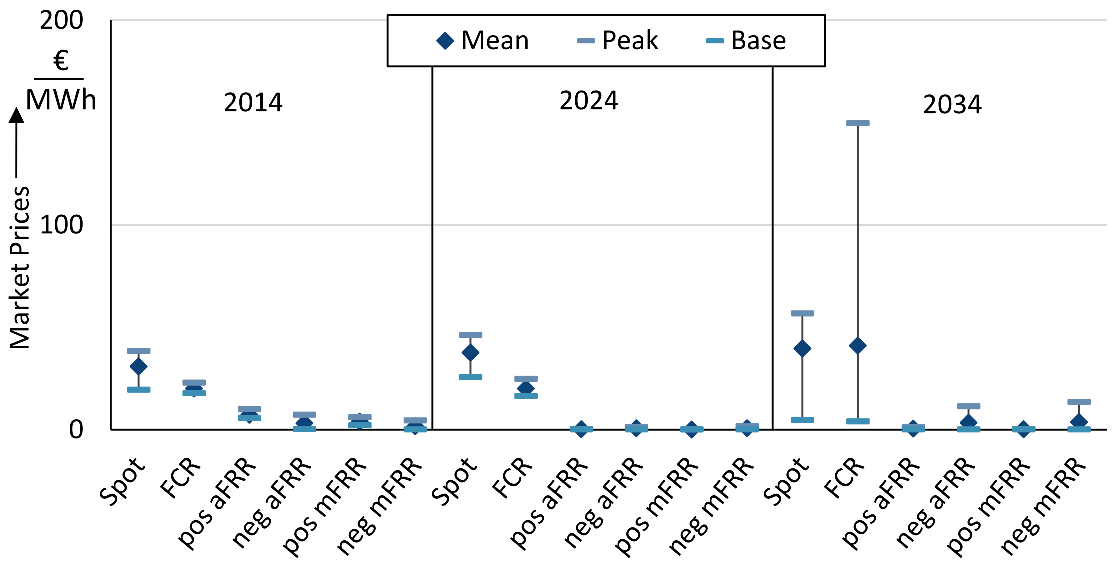


Figure 24: Simulation Results on Electricity Spot Market and Reserve Market Prices

5.3 Transmission Grid Simulation

The results for the transmission grid simulation for the year 2014 are displayed in Figure 25. It shows the line overloading before redispatch as well as the calculated optimal redispatch and RES curtailment that is needed to remove the congestions according to the (n-1)-principle. Especially on the transmission line between Bavaria and Thuringia (Redwitz – Remptendorf) as well as on the north/south transmission lines from Lower Saxony to the south of Hesse, frequent congestions occur. Overloading of these lines are mainly due to situations with a high wind power feed-in in northern Germany and thus large power transfers from northern Germany to the load centres in southern Germany. Consequently, in these situations, especially in the south, conventional power plants are ordered to increase their power feed-in whereas conventional as well as RES power plants north of the overloaded lines are ordered to reduce their power feed-in. The total amount of simulated yearly redispatch and RES curtailment is 6.7 TWh for 2014. The yearly RES curtailment alone accounts for around 0.5 TWh.

A comparison of the simulation results with historic data shows that the identified overloading of transmission lines in Bavaria/Thuringia and Lower Saxony/Hesse have in fact been bottlenecks of the transmission grid in 2014 [48]. In terms of the performed remedial measure in 2014, the total redispatch and curtailment volume induced by German transmission grid operators was 6.1 TWh. Curtailment of RES due to congestions in the transmission grid alone accounted for 0.9 TWh. The costs for these redispatch and curtailment measures added up to 269.4 million € [48].

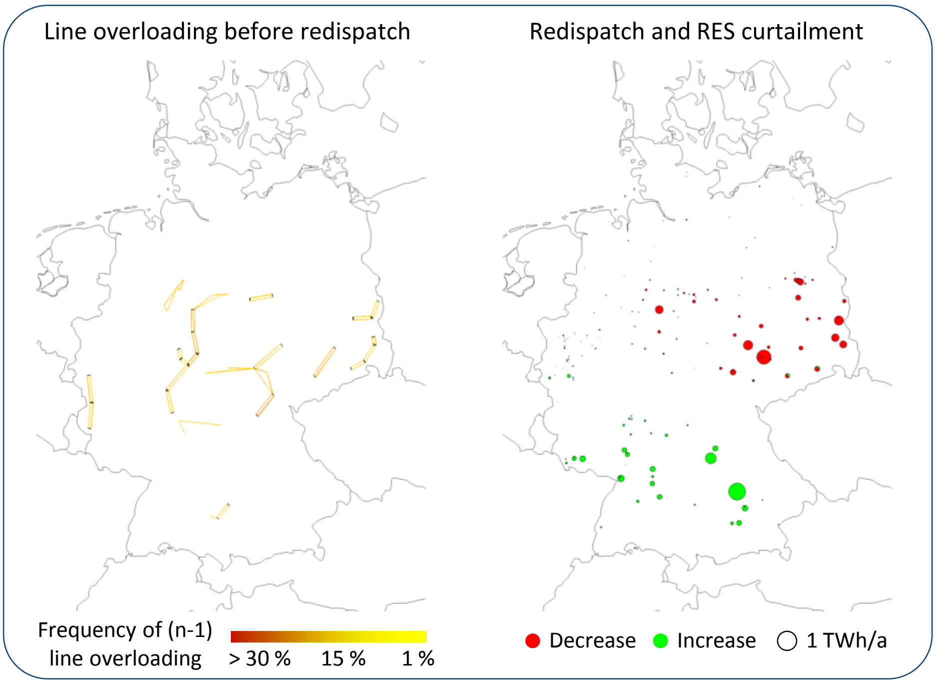


Figure 25: Line overloading before redispatch and redispatch/curtailment measures for transmission system simulation for 2014

The results of the transmission grid simulation for 2014 and the historic redispatch volumes for 2014 differ slightly. The neglect of topologic measures, the not explicitly modelled countertrading of transmission grid operators and the neglect of overhead line monitoring enabling an adaption of maximum line charging to weather conditions (e.g. performed by German transmission grid operators in case of high power transfers during strong wind situations [49]) lead to an overestimation of redispatch volumes compared to real operational practices. On the other hand, the assumption of optimized operational practices of transmission grid operators as well as the assumption of perfect foresight neglecting uncertainties of load and RES counteract this overestimation of redispatch volumes to a certain extent. Additionally, deviations may occur due to assumptions that are necessary for modelling the transmission grid model solely based on publicly available information.

Even though differences between historic data and the simulation results occur, this comparison shows that the applied transmission grid simulation can be used to estimate bottlenecks within the transmission grid and to generally evaluate necessary redispatch and curtailment measures to achieve a secure grid operation.

Figure 26 depicts the transmission grid simulation results for 2024. Even though the power transfer from northern to southern Germany increases in comparison to 2014 among other factors due to the expansion of wind power plants in northern Germany and the nuclear power phase-out by 2022, the total yearly redispatch and RES curtailment volume decreases to 3.3 TWh (total RES curtailment of 0.9 TWh). This decrease of necessary redispatch and curtailment originates in the grid expansion since the German grid development plan is directed towards a transmission grid that is free of congestions. Especially the four planned HVDC links connecting the wind power hubs in northern Germany to the load centres in southern Germany relieve the stress of the transmission grid, especially on the critical lines in Bavaria/Thuringia and Lower Saxony/Hesse. While the total number of overloaded lines increases, the frequency and height of line overloading during the year decreases resulting in reduced redispatch volumes.

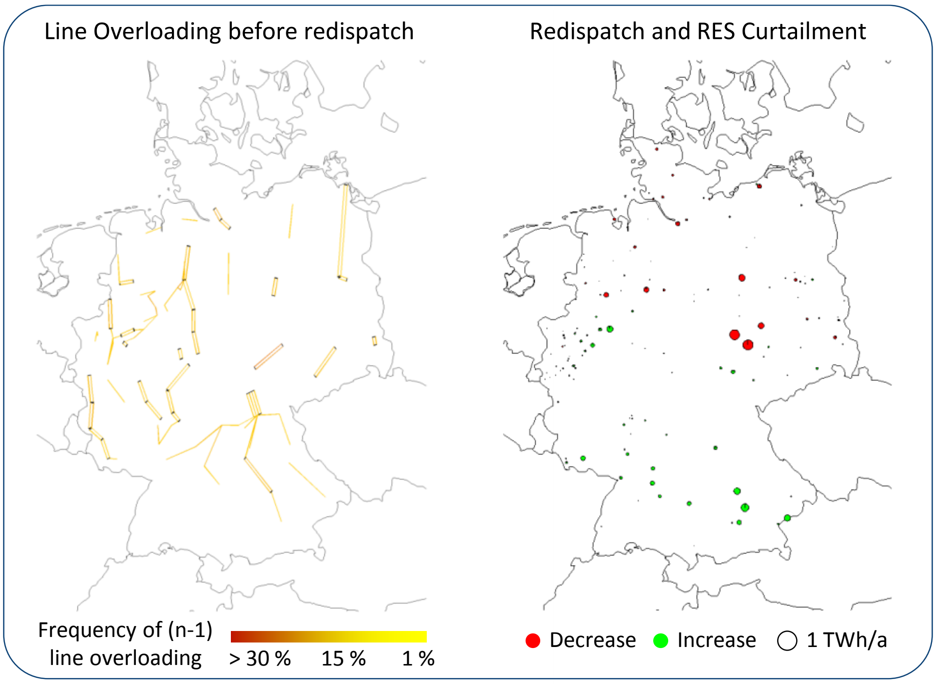


Figure 26: Line overloading before redispatch and redispatch/curtailment measures for transmission system simulation for 2024

Since the commissioning of the three eastern HVDC transmission links (Brunsbüttel – Großgartach, Wilster – Grafenrheinfeld, Wolmirstedt – Isar) might be expected later than 2024, the sensitivity analysis in deliverable 6.4 [45] includes an investigation of the effect of a scenario for 2024 only including the western HVDC link from Osterath to Philippsburg.

6 EVALUATION OF BUSINESS MODELS

6.1 Cross-Commodity Arbitrage Trade

Cross-commodity arbitrage trading is analysed in this chapter for current and future scenarios. An electrolyser, buying electricity from the spot market and selling hydrogen, uses opportunities of cross-commodity arbitrage.

Four countries are considered. They are chosen because they represent different market circumstances: high shares of solar power systems can be found in Spain, which may lead to low prices during PV peaks at noon. In Germany, a strong promotion of wind turbines and PV power systems is seen and an island position of an electricity market is represented by Portugal. The Netherlands are chosen because they represent a country with currently low RES shares in 2014 (10 %) and high shares of fossil fuels but show a strong transition towards high shares of RES in 2034 (56 %), especially focussing on wind turbines. The circumstances are used to identify most favourable conditions for electrolysers. Countries with high storage capacities or countries whose generation systems are solely based upon conventional generation units are not considered as they do not promise a favourable market situation for electrolyser applications directed towards interactions with the power system.

For cross-commodity arbitrage trading, the electrolyser is running at full load if the electricity price is low enough that hydrogen sales cover procurement costs and conversion losses, exemplarily shown in Figure 27.

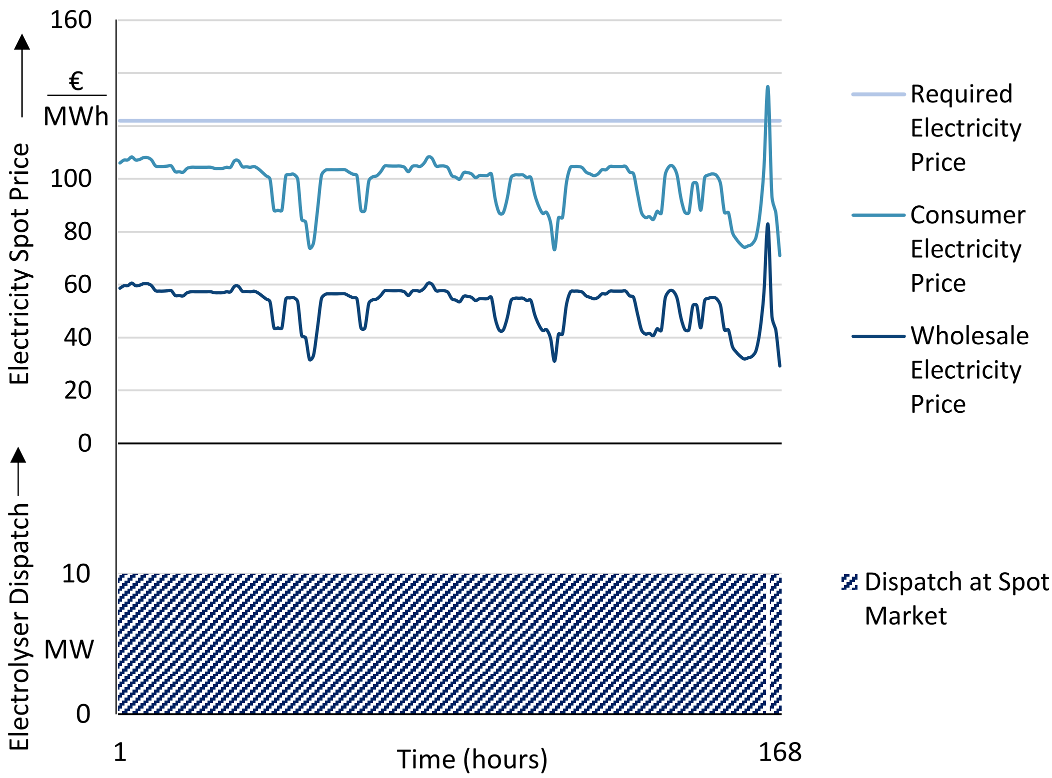


Figure 27: Electrolyser dispatch in one week in 2034 in Germany

Net margins are calculated for the four countries and three years. Net margins consider the revenues from hydrogen sales, costs for electricity and other marginal expenses as well as annual CAPEX and further OPEX. Costs, revenues and resulting net margins for Germany are exemplarily shown in Figure 28 for the year 2014. If electrolysers would have been exempted from taxes, levies and grid fees, an annual net margin of 147 k€/MW would have been possible when applying cross-commodity arbitrage trading. It can be seen that the hydrogen sales return almost 1 Mio. €/MW per year. In that case, the unit is running almost in base load with less than 10 hours not in operation. Because the unit is running in base load, no storage unit is needed for the 2014 setup. The highest annual costs arise from procurement with around 260 k€/MW for Supply and Trade and 270 k€/MW for electricity. Annual VAT amount up to around 100 k€/MW. Annuities of investment costs consist of around 100 k€/MW CAPEX for the electrolyser unit, around 70 k€/MW other CAPEX, and costs for a filling centre of around 28 k€/MW. Annual costs produced by OPEX and green certificates are between 1.5 k€/MW and 3.5 k€/MW. This leads to a yearly net margin of 180 k€/MW for the year 2014.

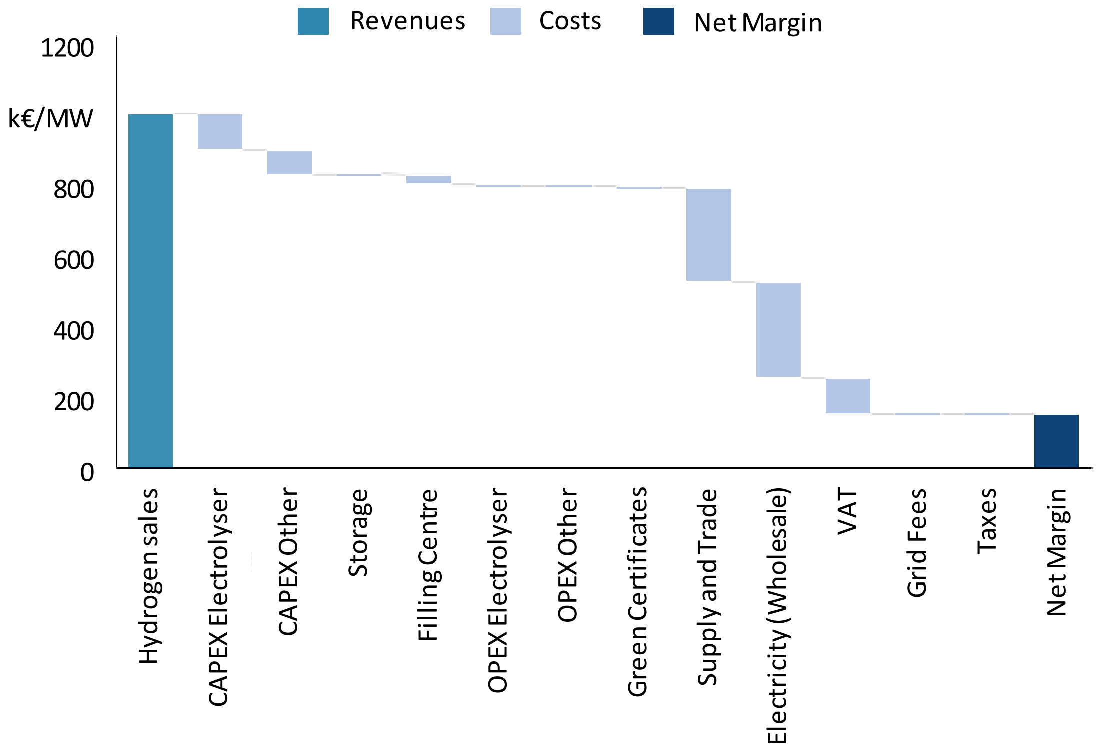


Figure 28: Cost and revenue and net margin for cross-commodity arbitrage trading in 2014 in DE

Within the results presented in the following, stack replacement costs are not included in the net margin calculation. The assumption of a stack lifetime of 90,000 hours and stack replacement costs of 216 k€/kW [21] would result in additional annuity costs of around 14.9 k€/MW for a worst-case estimation (operational hours of 8760 hours/year). Consequently, the net margin would be reduced by this amount.

Net margins for all four countries and time horizons resulting from cross-commodity arbitrage trading are presented in Figure 29. Overall, net margins are rising in future scenarios. Higher RES shares contribute to more hours with low or negative residual load which lead to lower electricity prices in those hours. It is visible that developments differ between countries due to different circumstances, strongly influencing potential business models for electrolysers.

In Spain and Portugal, net margins increase in 2024. Slightly higher margins in Portugal compared to Spain may be explained by the island position, because smoothing of volatile feed-in and prices are limited to the market area. In Portugal, net margins are increasing in 2034 as well. In Spain, with high shares of PV, an increase in net margins is observed between 2014 and 2024. In 2034, net margins decrease slightly in comparison. This may be explained by the simultaneity of solar feed-in. Generation peaks at noon lead to declines of prices during a few hours a day, but this effect is limited and may be exhausted already in 2024. Higher PV shares and low electricity prices during a few hours cannot compensate other effects of rising electricity prices. In Spain, less lignite is used for cheap electricity generation in the future and imports from France become more expensive because the French generation system is shifting away from cheap nuclear power generation.

In Germany, where continuously rising shares of RES are expected, net margins increase in 2024 as well as in 2034. The same effect is seen for the Netherlands. High shares of RES, especially wind turbines, produce electricity prices which come close to zero during many hours because marginal costs of RES electricity production are close to zero. Those low electricity prices are an advantage for the electrolyser, leading to a positive prospect for the future. An advantage of wind turbines is that the hours, where wind feed-in is high, are not as limited as for PV.

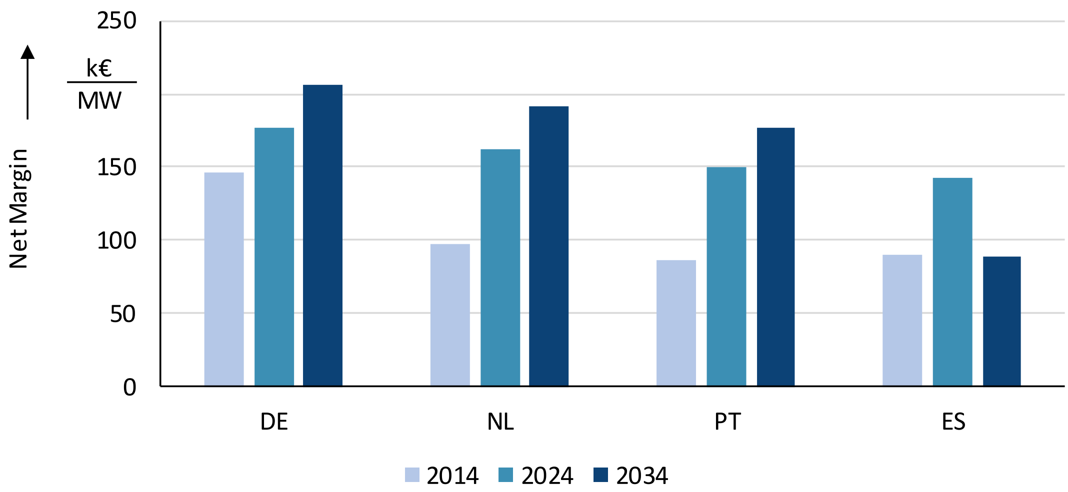


Figure 29: Net margins for a 10 MW electrolyser for cross-commodity arbitrage trading

In conclusion, rising net margins can be expected for the future when high shares of RES, especially wind power, characterize the market situation. This depends on lower electricity prices in hours with high RES feed-in but as well on exemptions from fees and taxes as well as on decreasing CAPEX as expected for the future.

Promising markets are those with large shares of wind turbines, because the fluctuating feed-in attributes for low market prices for electricity. Revenue increases at markets with high shares of PV may be limited at a certain level because the simultaneity of solar feed-in leads to a price reduction during only a few hours per day. Island positions of markets comprise dependencies of surrounding market areas, which have to be considered as well. Nevertheless, smoothing effects of feed-in curves should be less developed in market areas with island positions, which in turn produces peaks of low spot market prices, which may result in higher electrolyser revenues. High shares of conventional power plants that depend on primary energy prices and CO_2 emission certificate prices may lead to higher spot market prices, which do not promise a well-suited market environment for an electrolyser.

6.2 Reserve Market Participation

In the next step, additional revenues from the provision of control reserve are assessed. Net margins are calculated for business models 2-6, providing positive and negative aFRR and mFRR as well as FCR. The dispatch is optimized in the way that control reserve is only supplied when margins of the electrolyser unit are not negative within the single tenders and the dispatch of spare capacities are optimized against the spot market. In business model 7, net margins are determined for an optimal electrolyser dispatch where the unit is free to participate at the most profitable markets.

The German reserve market has some characteristics that need to be considered when interpreting the following calculation results. On the one hand, Germany is expected to have one of the highest shares of RES and decreasing shares of thermal power plants, thus fewer thermal plants are available for reserve provision. Because of that, revenues from the German control reserve market may be higher than in other European countries, giving an idea of an upper limit to possible reserve provision revenues. On the other hand, Germany's reserve markets are currently opening to a lot of new market participants. This is an advantage as well as a threat for electrolysers. The chance is that the electrolyser may be allowed for reserve provision in the future, but a risk is presented by decreasing reserve prices because of the rising competitions due to new market members. Thus, when transferring results to gain an idea of other European markets, specific market analyses are crucial for legitimate assumptions.

The power price for control reserve is paid without actual production of electricity or load respectively. For the electrolyser, this may be an opportunity to increase revenues compared to cross-commodity arbitrage trading.

Control Reserve Provision

At first, net margins from provision of FCR, positive and negative aFRR and mFRR are analysed. The unit dispatch for the specific business models is described in section 3.2. Net margins for a 10 MW electrolyser participating at the different reserve markets are shown in Figure 30 for years 2014, 2024 and 2034.

In 2014 as well as in 2024 and 2034, the higher net margins compared to cross-commodity arbitrage trading were achieved from participation in control reserve markets with positive aFRR and positive mFRR and with an optimized electrolyser dispatch. The optimized dispatch will be analysed in detail later on.

In future, net margins are increasing. The overall increase in net margins is due to higher RES penetration leading to more hours with low prices. This is true for spot prices but also for aFRR and mFRR prices, because price expectations of market participants towards the spot market influence their bidding behaviour at the control reserve markets. The trend is visible in 2024 as well as in the 2034 scenario. An exception is positive aFRR. Net margins from positive aFRR in 2024 are aligned net margins in 2014. A reason for that is the higher number of competitors from opening control reserve markets. For aFRR, tenders were reduced from one week in 2014 to 4 hours in 2024, following suggestions by ENTSO-E. This leads to more competition and declined prices in the aFRR market.

FCR presents the highest prices for reserve provision because available capacities which may serve as FCR control reserve units are scarce. Nevertheless, FCR is not the most profitable operation scheme for electrolysers which produce hydrogen for mobility purposes. FCR is required to be a symmetric bid, which means that capacity is reserve in the positive and negative direction. The units run between 1.5 MW and 6 MW. Then, the advantage of high prices for hydrogen cannot be taken efficiently.

Most profitable are positive aFRR and mFRR, less profitable is negative aFRR and mFRR. The required operation point accounts for higher full load hours and net margins for positive FRR. For the provision of positive FRR, the electrolyser runs between 6.5 MW and 10 MW in order to lower the load to minimal power when control power is called for, while it runs between 1.5 MW and 6.5 MW for providing negative FRR. The electrolyser does not exploit high spreads between the spot market and hydrogen market when running in the operation scheme for providing negative FRR. This overturns higher prices for negative FRR than for positive FRR.

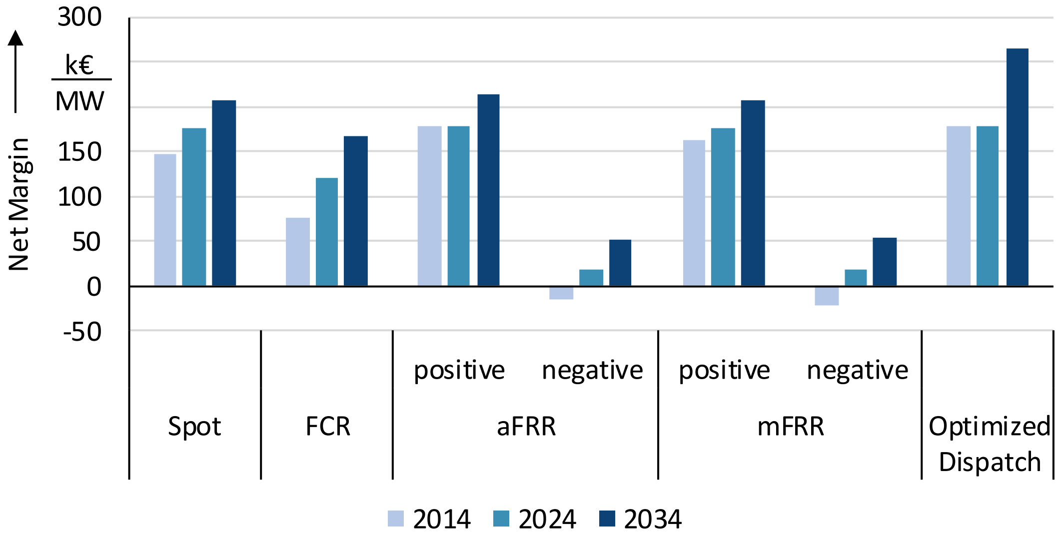
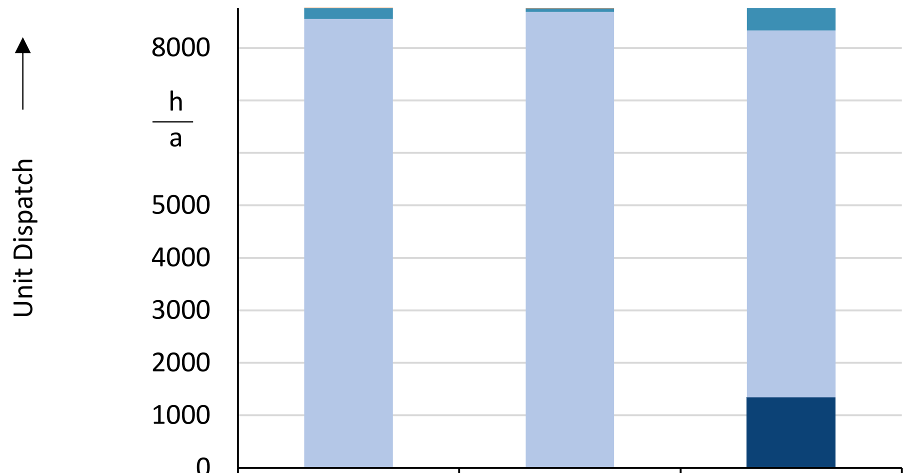


Figure 30: Net margins for a 10 MW electrolyser

The optimized dispatch returns the highest net margins compared to the other business models in all three simulated years. The optimized unit commitment of electrolysers takes not only one control reserve into account, but all reserve qualities under consideration of tender durations as well as cross-commodity arbitrage trading. In a first step, it is analysed whether it is more profitable to apply cross-commodity arbitrage trading or participate in the control reserve market during the time of the shortest tender, which is 4 hours, and the business model with the highest revenue is selected for the 4 hours. This is done for comparing the spot market and FRR. In the next step, revenues from FCR provision for the tender duration of one week are compared to revenues resulting from optimized dispatch between FRR and the spot market. This results in the selection of the most profitable market. The remaining available capacity, which differs between the business models, is optimized for cross-commodity arbitrage trading in every hour.

In the scenarios for 2014 and 2024, positive aFRR is most profitable and most frequently used for the optimized dispatch. In a few hours, positive mFRR and the spot market are selected. In 2034, FCR is selected besides positive aFRR and positive mFRR. Because of decreasing FRR prices in the scenario and higher mean electricity prices, it becomes more profitable to provide FCR and to run at 6 MW load than to participate at the spot market at full load. Overall, net margins are rising in the future. The highest net margins of 265 k€/MW can be seen in 2034 for the optimized dispatch.



	2014	2024	2034
Spot Market	4	8	0
Negative mFRR	0	0	0
Positive mFRR	204	64	428
Negative aFRR	0	0	0
Positive aFRR	8552	8688	6988
FCR	0	0	1344

Figure 31: Full Load Hours for Optimized Electrolyser Dispatch per Business Model

In conclusion, positive aFRR and mFRR are more profitable than negative aFRR and mFRR in all scenarios. A combination of participation at different markets shown promising increases of net margins. The electrolyser does not exploit high spreads between the spot market and hydrogen market when running in the operation scheme for providing negative FRR. This overturns higher prices for negative FRR than for positive FRR, as shown in section 5. However, it can also be seen that cross-commodity arbitrage trading is only slightly less profitable in the future when reserve and spot market prices are declining. Then, high spreads between the spot market and hydrogen market are harnessed most efficiently when capacities are fully available and not reserve for negative control reserve. Lost profits of non-produced hydrogen when production flexibility is bound to control reserve tenders cannot be compensated by profits from control reserve provision.

6.3 Provision of Transmission Grid Services

Based on the transmission grid simulation results presented in section 5 an estimation of electrolyser operation is undertaken evaluating the potential of electrolyser usage in order to absorb RES curtailment energy due to grid congestions that would otherwise be unused.

Therefore, it is assumed that the electrolyser as a load flexibility provider takes part in the congestion relieving process of transmission grid operators.

As discussed in section 3.1.4, the start-up of loads as part of the congestion relieving process in order to use RES curtailment energy is not yet part of the market based remedial measures of transmission grid operators. Consequently, it is uncertain how electricity prices or reimbursements for such a flexibility provision might be designed. A realistic estimation of potential net margins is therefore not possible. Hence, the evaluation of business models 8 and 9 is conducted through a calculation of full load hours based on the electrolyser operation schemes presented in section 3.2. Hereby, a general assessment of the theoretic potential for electrolysers to provide grid services can be made.

In order to effectively absorb RES feed-in that would otherwise be subjected to curtailment, the electrolyser needs to be located within the vicinity of RES power plants that are frequently curtailed. Figure 32 depicts the locations within the transmission grid that show a high amount of curtailment within the grid simulations for 2014 and 2024. For both years, mainly onshore wind power plants within the eastern part of Germany, especially Saxony-Anhalt, are subjected to curtailment. Since the simulations undertaken within this study are based on a fundamental approach and scenarios on future allocation of RES power plants within Germany, a definition of exact locations with high amounts of RES curtailment and therefore the identification of best suited locations for electrolyser placement is subjected to uncertainties. However, the fundamental approach enables to identify regions within the transmission grid that are most likely to show suitable locations for electrolyser provision of load flexibility for transmission grid services. Consequently, for electrolyser business models based on transmission grid services, suitable locations for electrolyser placement are expected to be within eastern Germany, especially within the area of Saxony-Anhalt.

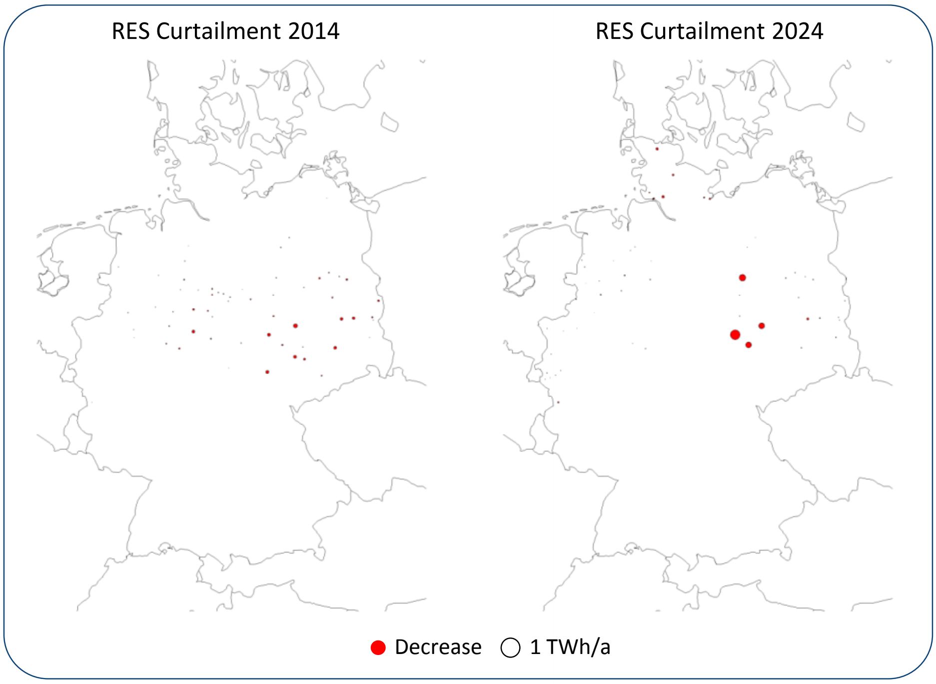


Figure 32: RES curtailment of transmission grid simulation for 2014 and 2024

For the evaluation of business model 8, it is assumed that in case an RES power plant would otherwise be curtailed, a 10 MW electrolyser installed at the same location is in operation in order to absorb the RES feed-in up to its maximum capacity of 10 MW. Within this investigation, it is neglected that an electrolyser could also be used to absorb RES curtailment energy from RES power plants that are positioned at neighbouring locations.

The corresponding full load hours for business model 8 are shown in Figure 33 for 2014 and 2024 for the 10 grid locations with the highest net margins identified by the fundamental model. These 10 locations are positioned within eastern Germany. The results show that the amount of full load hours is significantly dependent on the grid location. While in 2014 the full load hours for the best suited two locations are estimated to 447 and 399 hours, the full load hours rapidly decrease for other locations. The results also show that for 2024 the full load hours increase for the best suited locations even though the total amount of necessary redispatch and curtailment volumes decrease compared to 2014. This is due to the increase of wind power capacity especially in northern Germany in 2024. As a result, during situations with congestions on critical transmission lines, the potential of reducing the feed-in by conventional power plants is limited thus leading to a higher amount of wind power curtailment.

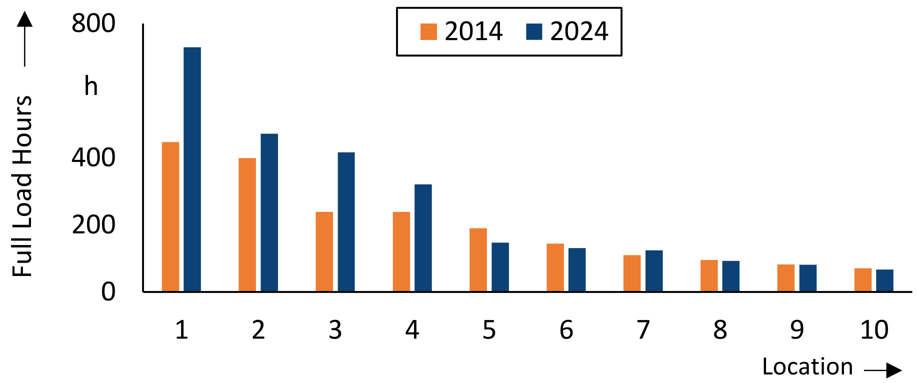


Figure 33: Full load hours for electrolyser providing grid services based on business model 8 for the 10 locations with highest full load hours

Figure 34 shows a comparison of electrolyser full load hours for 2014 and 2024 for the participation at the spot market for electricity (business model 1), the provision of transmission grid services (business model 8) and the participation at the spot market for electricity with additional provision of transmission grid services (business model 9). It can be seen that compared to spot market participation, the amount of full load hours of grid service provision is reduced by around 95 % in 2014 and 91 % in 2024.

Since for both scenarios due to the high hydrogen price the electrolyser is already in operation based on spot market participation throughout the year, a combination of both spot market participation and provision of grid services does not lead to additional full load hours. In case of lower electrolyser full load hours based on spot market participation, e.g. due to higher end-user prices of electricity or lower hydrogen prices, an increase of full load hours by business model 9 compared to business model 1 can be expected. However, it can be expected, that the increase of full load hours between business models 1 and 8 is diminished since the electrolyser cannot participate at the spot market and provide grid flexibility at the same time. Especially redispatch is often conducted during times of high wind power feed-in that result in grid congestions. At the same time, situations with a high RES feed-in are also one main cause of low prices on the spot market for electricity. Consequently, in times when the electrolyser could provide grid flexibility, it would often already be in operation due to spot market participation. This effect is clearly visible for the full load hours of business model 1 and 9 for 2024. This effect is investigated in the sensitivity analysis of deliverable 6.4 of the ELYntegration project [1].

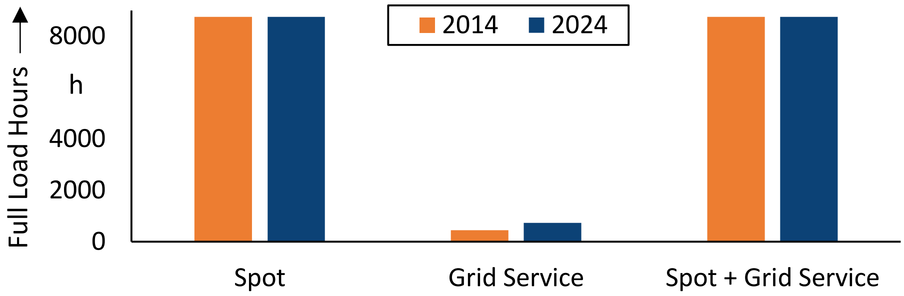


Figure 34: Full load hours for electrolyser based on business model 1 (spot), business model 8 (grid service) and business model 9 (spot + grid service)

It can be concluded, that the theoretical amount of full load hours of an electrolyser participating in the congestion relieving process of TSO in order to utilize RES feed-in that would otherwise be unused due to curtailment is highly dependent on the location of the electrolyser within the transmission grid. Consequently, it can be expected that the amount of full load hours is also highly dependent on the future allocation of RES power plants as well as the advance of transmission grid expansion planning. Since the expansion planning in Germany is directed towards a congestion free grid, it can be expected that the amount of curtailment will decrease in the long term. Consequently, the full load hours of the presented business models with electrolyser provision of grid services are expected to decrease in the long run compared to short or medium time frame. Additionally, it has to be emphasised that regulatory grounds for participation of electrolysers in grid services in terms of load increase are so far not provided. It is questionable whether the provided load flexibility of a single 10 MW electrolyser is practical for transmission grid operators in critical situations. An aggregation of several electrolysers would offer a more practical solution.

7 CONCLUSIONS

The technological enhancements of electrolyser subsystems pursued by the ELYntegration project enable highly dynamic electrolyser operation schemes. This increased flexibility opens new business opportunities in terms of fluctuating power supplies as seen within power markets with a high share of renewable energy sources in the generation system. Therefore, within this study, new potential business models for future energy applications of electrolysers were analysed, developed and evaluated. These are directed towards electrolyser participation at the spot market for electric energy, control reserve markets as well as potential future flexibility markets for grid services. Nine specific business models were considered and evaluated:

- BM 1: Cross-Commodity Arbitrage Trading
- BM 2: Provision of frequency containment reserve (FCR)
- BM 3: Provision of positive automatic frequency restoration reserve (pos. aFRR)
- BM 4: Provision of negative automatic frequency restoration reserve (neg. aFRR)
- BM 5: Provision of positive manual frequency restoration reserve (pos. mFRR)
- BM 6: Provision of negative manual frequency restoration reserve (neg. mFRR)
- BM 7: Optimized electrolyser unit commitment taking into account the spot market for electric energy as well as all control reserve markets
- BM 8: Provision of grid services within the congestion relieving process on transmission level
- BM 9: Cross-commodity arbitrage trading with additional provision of transmission grid services

In order to evaluate these business models, a fundamental simulation approach was used in order to model the spot market for electric energy and an agent-based simulation method for the modelling of the control reserve markets. Transmission grid simulations were undertaken based on a fundament approach as well. Short, medium and long term opportunities were estimated based on simulations set up for years 2014, 2024 and 2034.

The evaluation of the 9 developed business models was done by the assessment of resulting net margins considering CAPEX and OPEX including costs for electricity and fees, taxes and other costs as well as revenues from providing control reserve and based on sales of hydrogen for the mobility sector.

In terms of cross-commodity arbitrage trading, the simulation results show that positive net margins can be seen in all countries and time frames considered. Rising net margins can be expected for the future, when high shares of RES are characterising the market situation. Promising markets are those with large shares of wind turbines due to the fluctuating feed-in attributing for low market prices for electricity. Revenues at markets with high shares of photovoltaic power (PV) plants may be limited to a certain level because the simultaneity of solar feed-in leads to a price reduction in only a few hours per day. Island positions of markets comprise dependencies of surrounding market areas, which have to be considered as well. Nevertheless, smoothing effects of feed-in curves are expected to be less developed in market areas with island positions, which in turn results in lower spot market prices when RES shares are high enough, leading to higher electrolyser revenues. High shares of conventional power plants that depend on primary energy prices and CO_2 emission certificate prices may lead to higher spot market prices depending on primary energy price developments. This does not necessarily promise a well-suited market environment for an electrolyser.

In terms of electrolyser participation at control reserve markets, the simulation results show that provision of positive aFRR and mFRR are most profitable. Negative aFRR and mFRR are less profitable because the electrolyser does not exploit high spreads between the spot market and hydrogen market when restraining capacity for providing negative FRR. This overturns higher prices for negative FRR than for positive FRR. FCR has the highest market prices for reserve provision but nevertheless it is not the most profitable business model. Units providing FCE are running below full load and opportunity costs of losing revenues from hydrogen sales are higher than gained revenues from FCR provision. The optimized dispatch returns the highest net margins compared to the other business models in all three simulated years. The optimized unit commitment of electrolysers takes not only one control reserve into account, but all reserve qualities under consideration of tender durations as well as cross-commodity arbitrage trading.

In terms of electrolyser business models directed towards provision of grid services, from an electrolyser point of view, the provision of load flexibility for grid services could offer future potential of additional revenues. However, this potential is subjected to a high amount of uncertainties due to the advance of grid expansion, future allocation of RES power plants and especially an unclear design of future regulation. Currently, within Europe there is no regulation defining a potential electrolyser operation in order to absorb RES power that would otherwise be curtailed due to grid congestions. Compared to spot market participation, especially for scenarios of grid congestions caused by high RES feed-in, a significant increase of additional operational hours based on provision of grid services is not expected. This is caused by low spot market prices for electricity during situations of high wind power feed-in, resulting in electrolyser operation at the spot market and thus preventing grid service provision within these situations.

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9 APPENDIX

9.1 Market Simulation Methodology

In order to evaluate the profitability of different business models in the future, future electricity and reserve market prices are required. Different approaches are in use for the estimation of those prices. In this chapter, the price modelling methodologies are explained. Sensitivities towards different scenarios variations such as different RES shares in future markets are input parameters to the simulations. Thus, sensitivity analyses are carried out regarding different input parameter setups. Methodology and results of these analyses are presented in deliverable 6.4 of the ELYntegration project [1].

Simulation approaches for electricity markets

Commonly applied methodologies for spot or reserve market price simulations are analytical, stochastic, agent-based and fundamental modelling approaches. Analytical models derive correlations between input factors and electricity prices based on historical data [50]. Analytical approaches are generally useful for short term predictions of trends such as price developments, but are not able to include changing system environments or new components which change the formation of electricity prices. For example, historic based electricity price simulations cannot take changing price dynamics due to high CO_2 certificate prices into account. Furthermore, the further the required price information is set in the future, the less valid historic information is for an accurate assessment. As this study investigates scenarios up to 20 years ahead, a simple analytical approach does not suffice.

Stochastic modelling also relies on historical data to model the influence of stochastic factors. Stochastic factors influencing electricity prices are e.g. RES feed-in or power plant outages. For this simulation approach, the assumption is that prices can be modelled using stochastic processes [51] [52]. Like with analytical models, valuable results may be produced for short-term uncertainty assessments and price impacts [53], but a long-term price prognosis, especially considering changing dynamics due to a changing market environment, cannot be made.

If market pricing mechanisms are not close enough to a perfect market and thus fundamental models cannot be used for realistic price calculations, agent-based models may be used in order to depict market power and strategic bidding behaviour of market participants. Those factors cause a derivation away from fundamental prices based on variable costs. Agent-based models simulate the behaviour of market participants on a microeconomic level considering interaction between agents' bidding decisions and market results [54].

Fundamental models are widely used in the context of electricity generation system modelling. They optimize the power generation system under the assumption of perfect foresight and a perfectly competitive market disregarding portfolio limitations and strategic bidding of market participants [53]. One advantage of fundamental models is that structural changes of the supply and demand side are only happening slowly and the underlying cost structure is for the most part transparent. Also, electricity pricing auction designs as well as market regulations lead to only limited market power in most markets and situations. With this observation, the assumption of a perfect market is approximately viable for spot markets in

Europe. In uniformly priced market, power plants have a strong incentive to bid according to their variable costs, generating contribution margins if a higher bid sets the uniform price. This enables a price calculation considering a variable cost based merit order. Results of fundamental simulations do not only include electricity prices, but also exchanges between bidding zones and detailed information about the dispatch of power plants. Those results may be used as input parameters for further investigations e.g. concerning the power flow. Because fundamental models derive prices considering the market surrounding such as shares of different types of plants, RES feed-ins or load developments, they are well suited for a price simulation for future scenarios with different set-ups. Therefore, a fundamental spot market simulation is conducted within this study.

9.1.1 Fundamental Spot Market Simulation

Spot market prices required for the assessment of future electrolyser business model developments are calculated using a fundamental approach. A detailed description of the simulation approach can be found in Drees (2016) [55]. The fundamental approach conducts a minimization of the total costs for power generation for an entire year in an hourly resolution for European countries considering exchanges between bidding zones. The optimization approach considers the following technical and economic parameters:

- detailed generation stack of all coupled market areas,
- demand for electrical energy and balancing reserves,
- technical parameters and limited availabilities due to power plant outages,
- the variable costs of power plants,
- primary energy and emission certificate prices,
- dispatch constraints.

The bids of power plants which determine the price of the day-ahead electricity depend on all cost components described before, because they determine the economic operation. Realistic prices are thus derived from the consideration of variable production costs, start-up costs and avoided costs of a new start-up when producing at minimum power during short periods of expected low prices. Therefore, detailed technical parameters have to be incorporated. Furthermore, availabilities and reserve provision have to be simulated as well as exchanges of the entire European generation stack.

This problem results in a highly complex optimization problem with time-linking constraint in the management of storage power stations and minimum operating and downtimes of thermal power plants. Thus, a closed-loop formulation of the problem is not feasible in practicable computation times. Therefore, this market simulation method is based on a multi-stage Lagrangian Relaxation and Decomposition approach as depicted in Figure 2 [56].

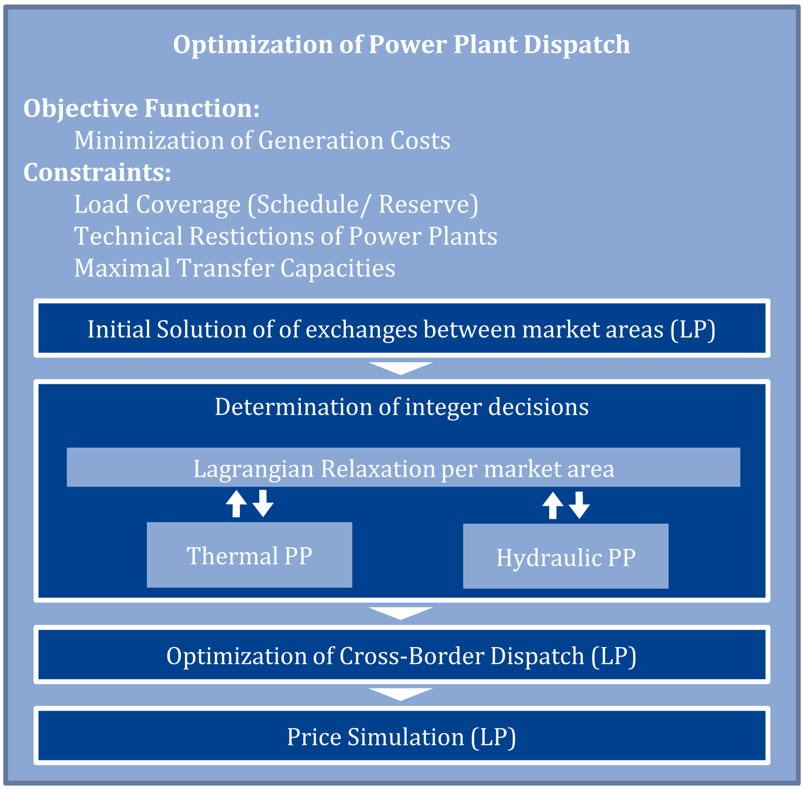

Figure 35: Overview of Fundamental Day-Ahead Market Simulation Approach

A linear approach using linear programming (LP) techniques is used for the first step of the optimization, which computes an initial solution for the exchanges between market areas. In a second step, a determination of integer decision is done for the optimization of the power output P and start-up decisions for the generation stack e in each market area with fixed exchanges between the areas. The optimization is solved by iteratively relaxing the load coverage μ, the reserve provision constraints λ and the Lagrangian function L. Due to the Lagrangian Relaxation, the dual function can be decomposed, separating it into thermal and hydraulic sub-problems [57] [58].

$$\max_{P} \min_{\lambda,\mu} L(P, e, t, \lambda, \mu)$$

The start-up and operating decisions for each flexible generation unit are determined considering all relevant technical restrictions. With the decomposition into thermal and hydraulic sub-problems, the different types of plants are optimized using different algorithms which adapt to the respective problems. Hydraulic power plants are optimized using linear programming while thermal power plants are modelled using dynamic programming considering start-up costs and minimum up- and downtimes.

Only integer decisions such as thermal unit commitment are adopted from the second stage to the third stage, because due to the relaxation the results may fail to comply with all load and reserve constraints. This is adjusted in the third stage, where remaining continuous optimization problems are solved in a closed loop approach in order to assure the compliance with time and system coupling constraints. The step is used to calculate the power exchange between the countries of the system in consideration of the technical constraints, resulting in the cost-minimal power plant dispatch of the European power plant fleet. Furthermore, cross-border power exchanges are main results of this optimization.

An additional linear approach is finally used for the simulation of electricity prices, which represent day-ahead spot prices. The dual variables of the load coverage constraints represent the bidding price of the last cost-optimal power plant in operation, thus providing the market clearing price of the spot market. In this context, the bid of a power plant is represented by the objective value in each hour. Additional positive and negative mark-ups for start-up and avoided start-ups are considered using the system costs for the respective hour. In hours with system costs below variable production costs, it is an opportunity for the plant to bid below its variable costs in order to avoid the costs of an additional start-up. Those avoided start-up costs are deducted from the variable costs.

9.1.2 Agent Based Control Reserve Price Simulation

As reserve market prices are highly dependent on strategic bids of the market participants, an agent-based reserve market price simulation is used for the derivation of future reserve prices. As mentioned, agent-based models simulate the behaviour of market participants on a microeconomic level considering interaction between agents' bidding decisions and market results [54].

This simulation is based on the fundamental simulation of the spot market. From there, long term restrictions for hydraulic power plants as well as exchanges to and from the German market area are taken. The prices of the fundamental market simulation serve as initial price expectations for the day-ahead (DA) market prices. The various auctions take place in a defined chronological order. This is also reflected in the simulation. The clearing of those markets is conducted sequentially in the order in which they are cleared in Germany. Figure 36 illustrates the developed approach and shows the relationships between bidding simulation, price expectations and auction results. For each market, price expectations and results of prior markets are considered as well as the limited planning horizon of market participants. In order to compute the market prices of the control reserve markets, the model simulates the bidding decisions of all market participants (agent) in the different auctions. The market prices result from a matching of a given demand for control reserve and the bids of the modelled agents. This matching is done according to the specific set of rules of each auction.

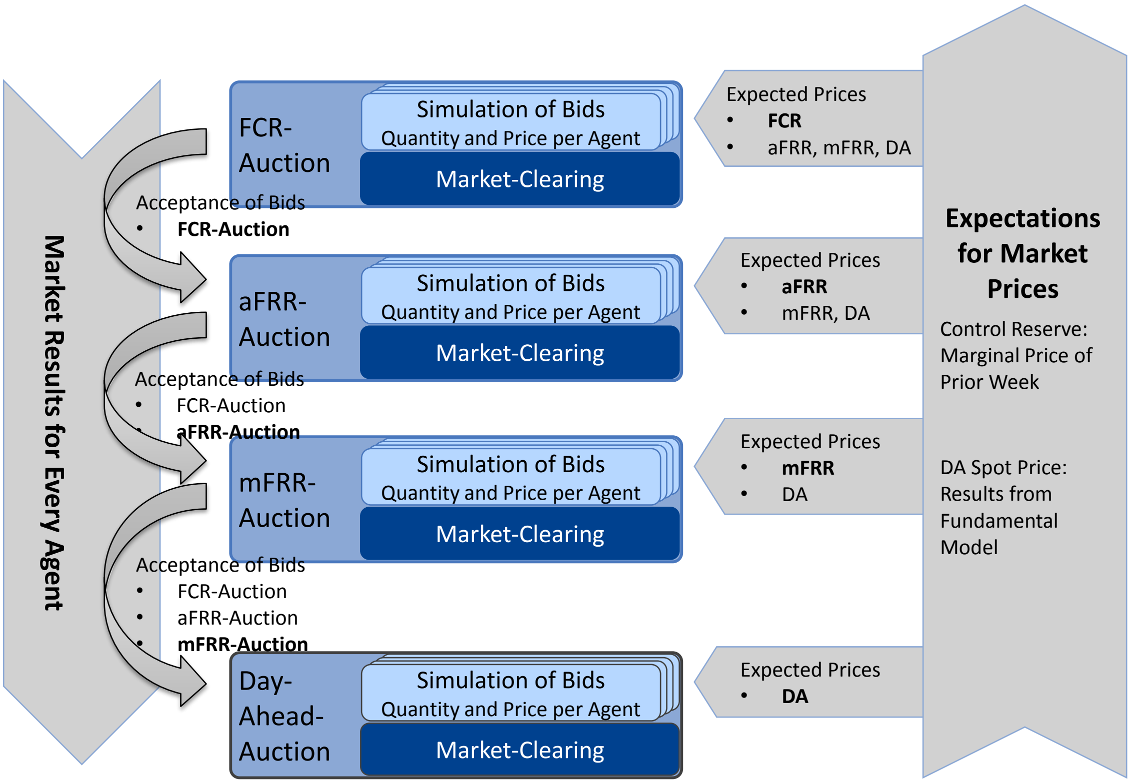

Figure 36: Overview of Agent-Based Reserve Market Simulation Approach

For each market step the bidding of the agents is simulated. Each storage or generation unit is modelled as one agent in the simulation. Firstly, a dispatch and trading optimization is performed taking into account the specific technical restriction of the modelled units. Aim of the optimization is to maximize the contribution margin generated by providing reserve and acting on the day-ahead spot market considering each agents price expectation. The price expectation for the day-ahead market is derived from the result of the fundamental market simulation. Since the prices at the reserve markets are depending more on the bidding situation than on fundamental input factors, the marginal prices of the last simulated reserve auction are used as the price expectations in the dispatch optimization. Based on the dispatch optimization and the expected market prices, the bidding volumes and prices are computed for each agent. The bid prices consist of fundamental cost components and opportunity costs from expected day-ahead revenues.

The product design of the reserve auctions is based on the current market situation in Germany including foreseeable changes of the aFRR auction design. Therefore 52 weekly auctions for FCR and 365 daily auctions for aFRR and mFRR are simulated concurrently. The result of each auction impacts the potential bidding of the agents in the coming auctions since the resources can only be allocated once for reserve provision or generation at the spot market.

9.2 Transmission Grid Simulation Methodology

In order to evaluate the business opportunities of water electrolysers for providing load flexibility towards transmission systems operators (TSO), estimations on future transmission grid congestions and the amount of redispatch for removing these congestions are necessary. In order achieve realistic results, the operational practices and regulatory constraints, described in section 3.1.4, have to be considered in an adequate way in a redispatch model. This includes the (n-1)-principle as well as the hierarchical activation of the most effective and economically efficient remedial actions. Regardless of the technical setup for the redispatch model, the (n-1)-principle is the applied security criterion in all calculations and must be considered by performing contingency simulations. The redispatch model used within this study uses a fundamental approach based on an optimization problem design [59]. It was developed in cooperation with European TSO and research facilities as part of a study for the European Union and determines optimized redispatch measures for a given grid parametrization [60]. The optimization problem is based on linear sensitivities. These are calculated for all remedial measures in order to identify their impact on the congested lines. Within the simulations presented in this deliverable, the following remedial measures are considered:

- Phase-Shifting Transformers (PST)
- Redispatch of conventional power plants
- Curtailment of RES
- Activation of reserve power plants

In order to minimize the socio-economic welfare loss generated by redispatch, the selection of redispatched power plants is based on the quotient of costs and effectiveness to resolve the congestions. Low-priced power plants are redispatched with a higher priority, unless more expensive power plants can resolve congestions more efficiently. This is ensured by considering marginal costs as an outcome of the market simulation described in section 4. Virtual volume costs are employed for all remedial measures in order to reduce the utilization of redispatch and to comply with regulatory constraints. For example, high volume costs penalize the curtailment of RES to ensure that the power decrease of conventional power plants is favoured. The volume costs are not considered within the calculation of total redispatch costs as they are virtual. The total costs for redispatch are based on marginal costs from the market simulation and correspond to the change of the market based electricity generation.

However, there is a need to distinguish between redispatch costs seen by the TSO and welfare effects due to redispatch utilization. TSO have to pay monetary compensation to operators of conventional power plants that are increased and for energy not served due to curtailment of RES power plants. On the other hand, TSO receive payments from operators of power plants that are decreased in their power output. The costs accrued from the compensation of RES curtailment correspond to a redistribution and thus have no effect on the social welfare.

The redispatch model is based on the result of the market simulation: the hourly dispatch of each generation unit and load. This dispatch is transferred onto the model of the European transmission grid. This enables the calculation of load flow and thus the application of the redispatch model. Formulated as a Security-Constrained-Optimal-Power Flow (SCOPF), this model is capable of determining an optimized set of remedial measures. This is done by minimizing the violations of operational constraints, especially overloading of lines in contingency situations according to the (n-1)-principle. The considered remedial measures in this study are the adjustment of power plant operating-points including start-up decisions of power plants as well as tapping of transformers such as phase-shifting transformers. The SCOPF is solved using a successive linear optimization process, which is shown in Figure 37.

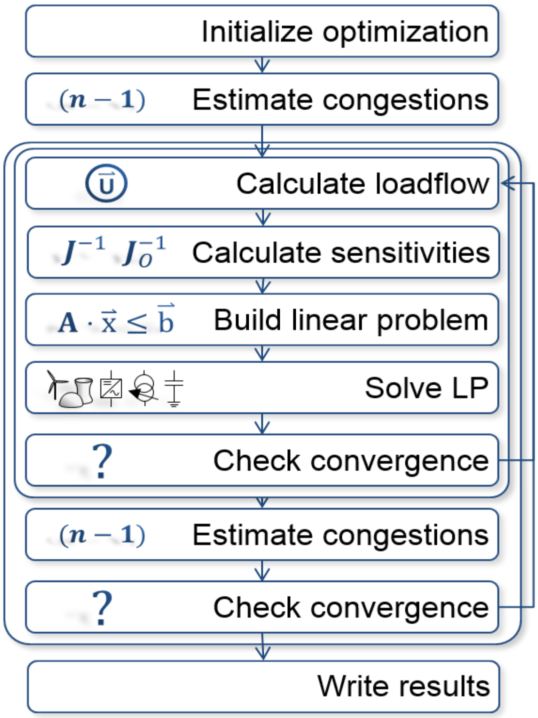

Figure 37: Optimization formulation of redispatch model

In a first step, the optimization is initialized and an estimation of congestions is performed. After that, the problem is linearized by calculating sensitivities. These sensitivities describe the impact of a change of feed-in into a specific grid node on the amount of line loading on a branch. These can be obtained indirectly from the Jacobian Matrix out of the Newton-Raphson load-flow calculation. The sensitivities are used to set up a linear optimization problem with all considered degrees of freedom and linear constraints, which is solved by use of a simplex algorithm. Being a simplification, this linearization is necessary in order to guarantee an efficient solution. Therefore, another complex load flow simulation verifies the optimization results. In case of remaining overloadings, this procedure is repeated iteratively until all overloadings have been mitigated. Remaining overloadings of lines in the intermediate as well as the final results are possible but penalized. Thus, solvability is ensured and conclusions about operational grid security become possible if no measures for eliminating a congestion exist. [59]

This approach does not model the reality in an exact way, since the congestion handling process by the TSO is a stepwise approach to determine remedial actions. However, this fundamental approach is the most reasonable method to compare redispatch volumes and costs for future transmission grid and generation system scenarios, even though deviations from historic redispatch volumes and costs can occur.

Hence, this model can be used in order to identify not only suitable locations within a transmission grid where flexibility provision of electrolysers can be used within a business model of shiftable loads based on the assumption of a potential new flexibility market, but also to estimate the operational hours of the electrolyser within such a scenario. Additionally, due to the direct interrelation of the market simulation and the redispatch simulation, a electrolyser business model can be evaluated, in which the electrolyser has the possibility of participating both at the spot market for electric energy and within redispatch.

9.3 Control Reserve Specification in European Countries

Table 3. Demand response and activation time for control reserve in European countries [61] [62] [63] [64]

Country	Notation	Participation	Participation by agg. loads	Activation time	Tenders
Austria, Germany, Switzerland	FCR	✓	✓	30 s	weekly
	aFRR	✓	✓	5 min	weekly
	mFRR	✓	✓	15 min	4 hours
	RR	-	-	-	-
Belgium	FCR	✓*	✓*	15 - 30 s	annual
	aFRR	×	×	-	
	mFRR	✓*	✓*	3 - 15 min	
	RR	×	×	-	
Denmark	FCR	✓	✓	30 - 150 s	N/A
	aFRR	✓	✓	15 min	N/A
	mFRR	✓	✓	N/A	N/A
	RR	✓	✓	N/A	N/A
Finland	FCR	✓	✓	inst. - 3 min	annual
	aFRR	✓	✓	2 min	annual
	mFRR	✓	✓	15 min	N/A
	RR	✓	✓	15 min	N/A
France	FCR	✓	✓	< 30 s	flexible
	aFRR	✓	✓	< 15 min	
	mFRR	✓	✓	13 min	
	RR	✓	✓	30 min - 2 hrs	
Great Britain	FCR	✓	✓	2 s	flexible but long-term (e.g. daily weekday participation)
	aFRR	✓	✓	2 min	
	mFRR	-	-	-	
	RR	✓	✓	2- 4 hours	
Ireland, Italy, Poland, Spain	FCR	×	×	-	-
	aFRR	×	×	-	
	mFRR	×	×	-	
	RR	×	×	-	
Netherlands	FCR	×	×	-	
	aFRR	✓	×	N/A	annual
	mFRR	✓	×	N/A	voluntary bids
	RR	-	-	-	-
Norway	FCR	✓	✓	5 - 30 s	hourly, weekly
	aFRR	✓	✓	2 min	weekly
	mFRR	✓	✓	15 min	weekly, seasonal
	RR	×	×	-	-
Slovenia	FCR	✓	×	N/A	annual
	aFRR	✓	×	N/A	
	mFRR	✓	✓	15 min	
	RR	-	-	-	
Sweden	FCR	✓	✓	5 s - 3 min	daily
	aFRR	✓	✓	2 min	weekly
	mFRR	✓	✓	15 min	hourly
	RR	✓	✓	15 min	yearly

* partially accepted

✓	Demand Response accepted	×	Demand response not accepted
-	Reserve does not apply	N/A	Information not available

9.4 Electrolyser Key Performance Indicators

Table 4: Development of alkaline water electrolyser efficiency [33]

Power Consumption [kWh_{el}/kg_{H2}]	2015	2020	2025	2030
Medium	53	52	51	50
Range	50 - 73	49 - 67	48 - 65	48 - 63

Table 5: Development of electrolyser system costs for alkaline water electrolysers [33]

$CAPEX_{ely}$ [€/kW]	2015	2020	2025	2030
Medium	930	630	610	580
Range	760 - 1,100	370 - 900	370 - 850	370 - 800

Table 6: OPEX of electrolyser system for different plant sizes [33]

Plant Size [MW]	$OPEX_{ely}$ [% of electrolyser system $CAPEX_{ely}$ per year]
1	5,0
5	2,2
10	2,2
20	1,85

Table 7: Approximation of CAPEX and OPEX for "other costs" (civil works, engineering, control system, interconnection, commissioning, start-up) [21]

Plant Size [MW]	$CAPEX_{other\ costs}$ [% of equipment costs]	OPEX [% of $CAPEX_{other\ costs}$]
1	60,0	4,0
5	40,0	4,0
10	37,5	4,0
20	36,0	4,0

Table 8: Development of CAPEX of stationary hydrogen storage systems [21]

$CAPEX_{H2\ storage}$ [€/kg]	2017	2025
50 bar (tank)	470	470
200 bar (bundle)	470	470
350 bar (bundle)	470	470

Table 9: Estimated cost for filling centre [21]

$CAPEX_{filling\ centre}$ [k€]		Estimated value
30 bar → 200 bar	20 kg/h	467
30 bar → 200 bar	100 kg/h	1351
30 bar → 200 bar	400 kg/h	3373

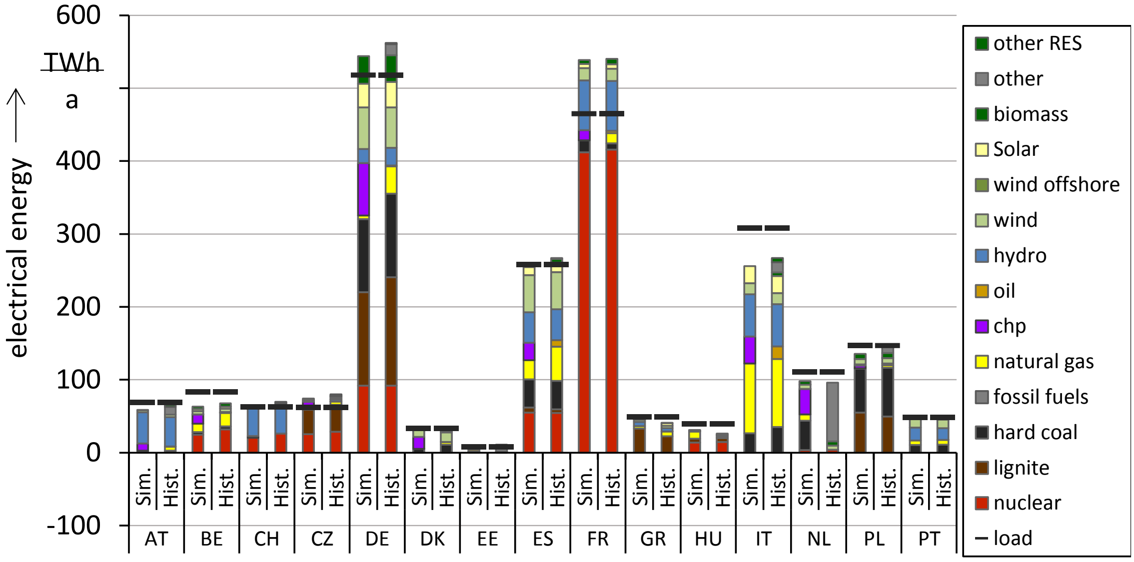

Figure 38: Simulated and historic annual energy generation in 2024 in Europe

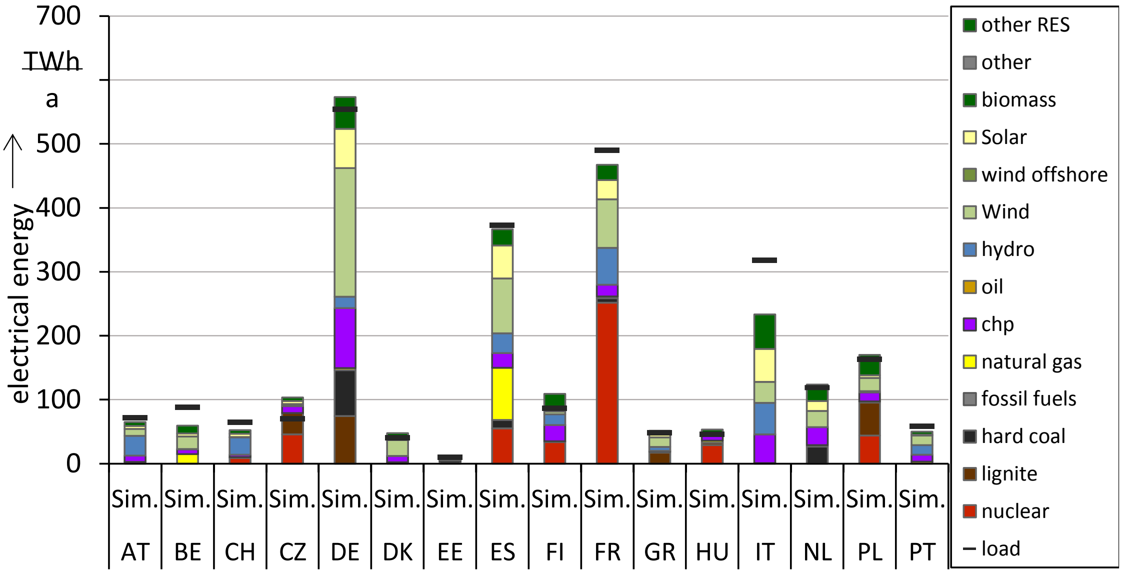

Figure 39: Simulated annual energy generation in 2024 in Europe

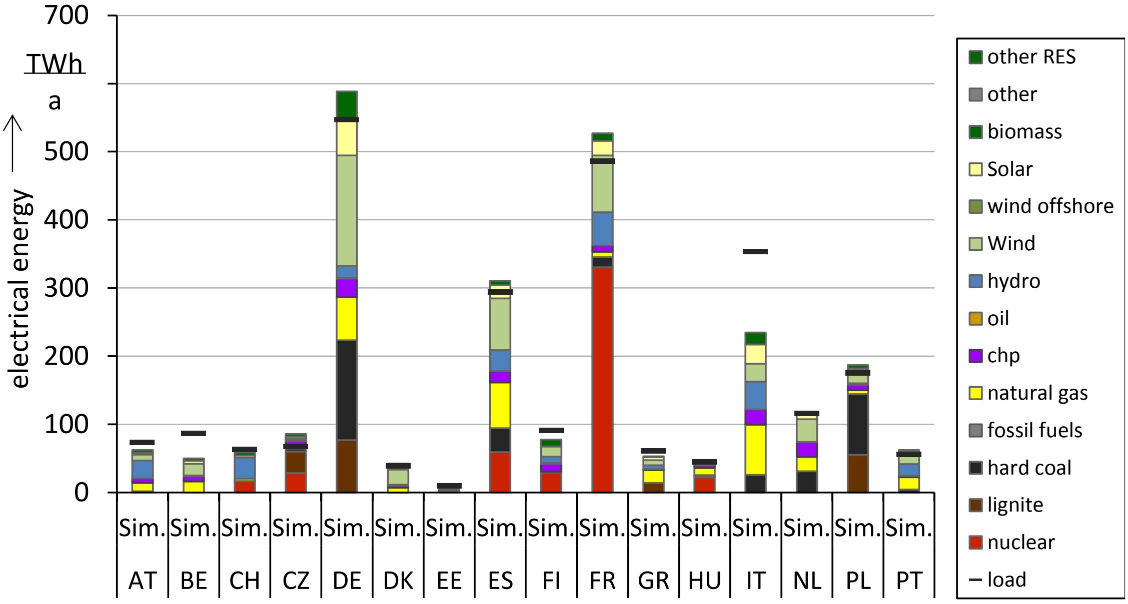

Figure 40: Simulated annual energy generation in 2034 in Europe

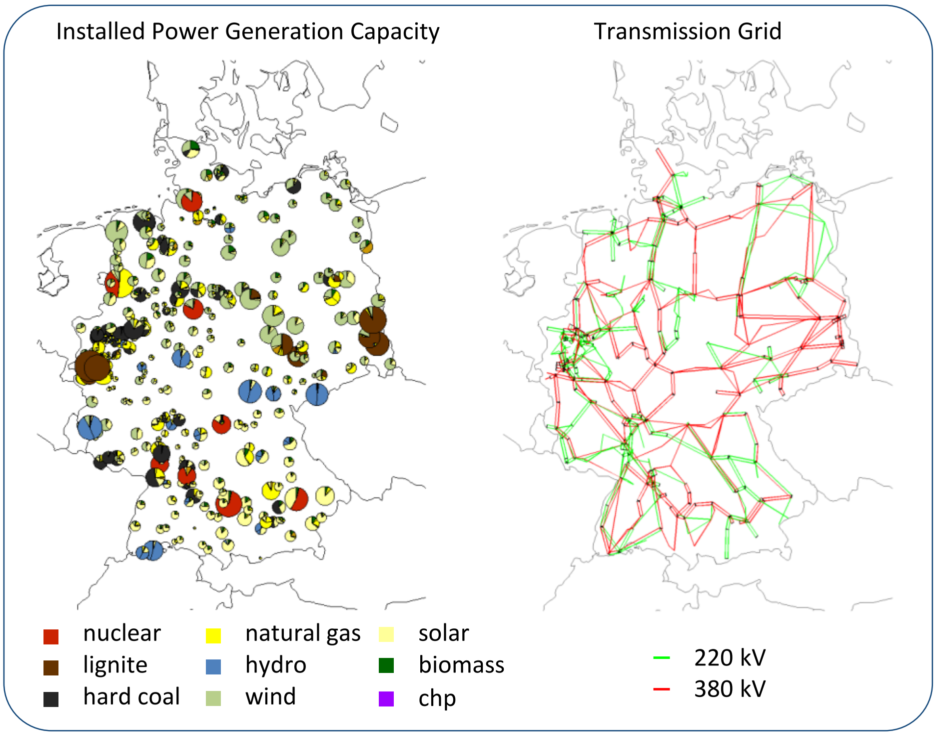

Figure 41: Installed power generation capacity and transmission grid model in Germany for year 2014

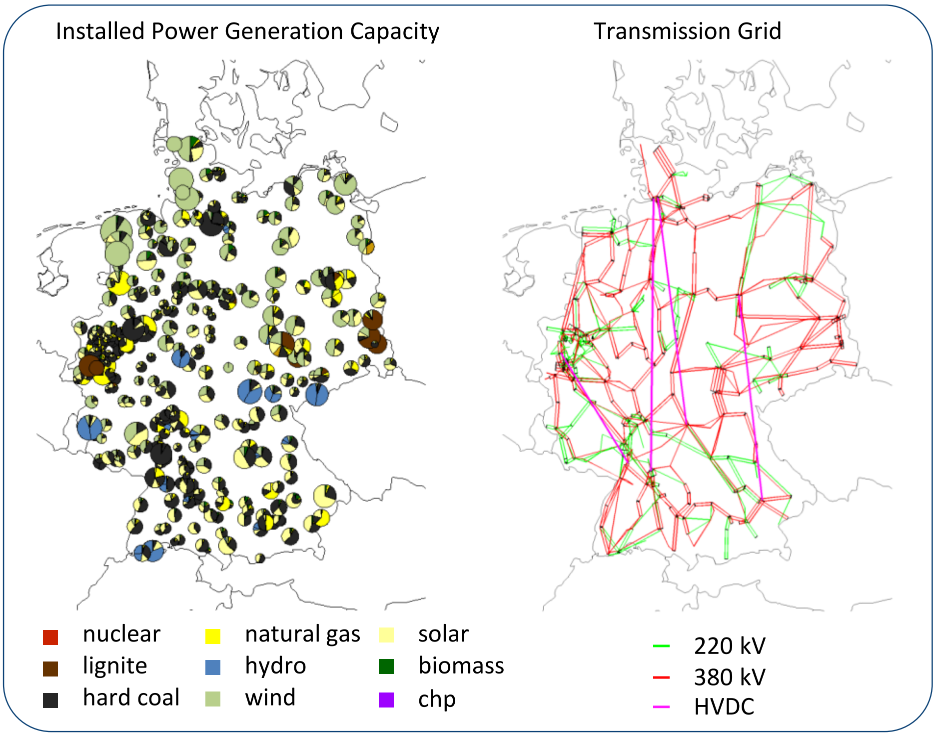

Figure 42: Installed power generation capacity and transmission grid model in Germany for year 2024