European energy system model description

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1. General model overview

1.1.Simulation platform and system boundaries

The modelling of the European energy system in this study is based on a simulation platform developed by LBST to perform detailed techno-economic system analyses with a flexible technology focus and geographical scope at various scales. The **LENS model** (**L**BST **EN**ergy **S**ystem **model**) optimises the size and operation of different elements of a predefined system in a given location and for a given time frame. This is done in a top-down approach by taking several economic and technical constraints into account. It can be easily adapted to capture most important features of the underlying problem and is designed to perform multitude of calculations in short computational time in order to assess and compare different scenarios and sensitivities according to the individual study scope. This explorative character of the model-based analysis allows to test the impact of different assumptions and input parameters on the overall system results. In this way strategic decision making can be supported by a quantitative analysis in a flexible and efficient way within one overarching modelling platform.

In general, the LENS model is formulated as linear programming (LP) problem for the purposes of this study with the objective to minimize the overall system costs subject to a number of techno-economic constraints in each of the modelling steps. According to the categories presented in Michalski (2016) it can be characterized as a deterministic system equilibrium model under perfect competition with exogenous price representation (i.e. individual market players are considered as price takes). Depending on the modelling step it is based on both the single- and multi-node approach (see Chapter 1.2). Hence, the modelling exercise provides insights from the societal and macroeconomic perspective rather than from the business perspective of individual market participants.

The initial model formulation is related to the analyses on the role of energy storage technologies in energy systems with increasing share of renewable electricity from the microeconomic perspective and can be traced back to the work provided in Michalski (2016). Consequently, early LENS model applications focused more on single facilities such as Power-to-Gas (PtG) plants connected to a hydrogen (H_2) storage at one location but in greater technological detail from the business perspective[1]. More recent studies employed an extended model version with a larger scope but in smaller technological detail in order to analyse whole supply infrastructures, e.g. for hydrogen refuelling stations,[2] or integrated energy system at national[3] and pan-European level[4].

The boundaries of the European energy system assumed in this study are presented in Figure 1. In general, the model takes into account the infrastructures for power and hydrogen as two major energy carriers in the subsequent analyses. On the electricity side, power plants represent the major supply source of the underlying system. Typically, they can be subdivided

[1] See e.g. DLR et al. (2015), Michalski (2016), Bünger et al. (2016), Albrecht et al. (2016) or Michalski et al. (2017).

[2] See e.g. Bünger & Michalski (2018) or Michalski et al. (2019).

[3] See e.g. Michalski (2017), Michalski et al. (2019) or Bünger et al. (2019).

[4] See e.g. Trinomics/LBST/E3M (2019).

into intermittent renewable power plants (such as wind onshore and offshore as well as photovoltaics - PV) and flexible dispatchable power plants based on fossil (e.g. coal or natural gas), nuclear or renewable (i.e. biomass or biogas) fuels. The modelled power infrastructure consists on the one hand of power lines required to transport electricity between the different grid nodes and on the other hand of a number of flexibility elements including electricity storage (e.g. pumped-hydro storage or stationary batteries), curtailment of intermittent power plants and demand side management.

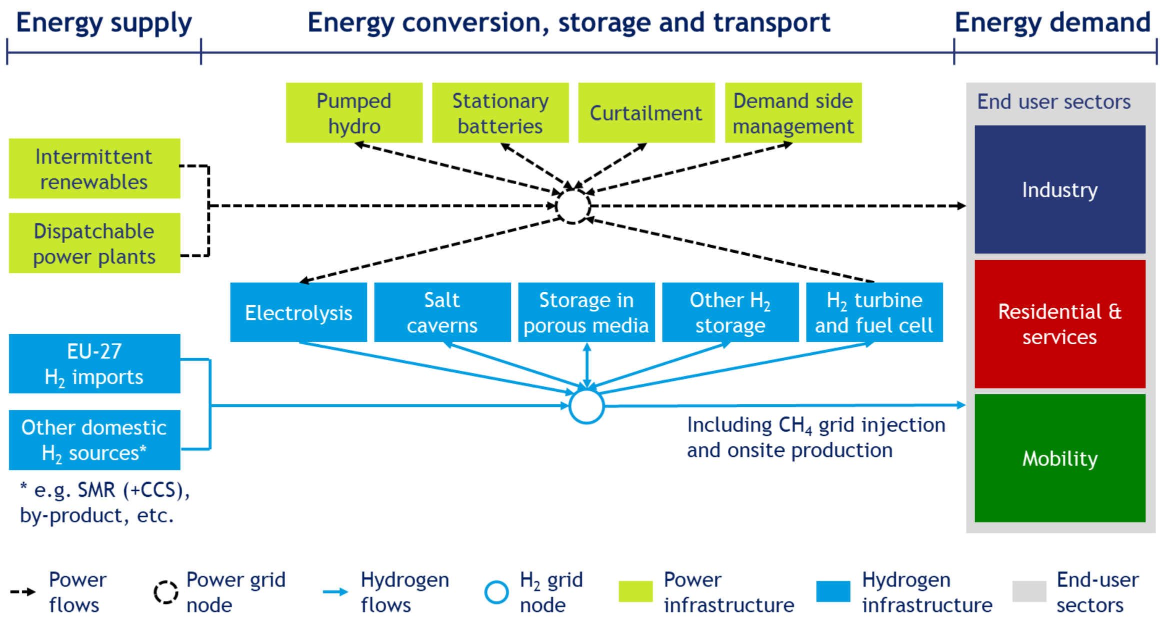

Figure 1: Boundaries for energy system within the LENS model adapted for this study

On the hydrogen side, electrolysis is the core supply unit converting electricity into hydrogen and thus being a major sector coupling element in the system. The model takes also into account other potential supply sources such as hydrogen imports from outside the EU and, at least in the transition phase, conventional hydrogen production via steam methane reforming (potentially with Carbon Capture and Storage (CCS) or as by-product H_2). In order to ensure the overall system flexibility H_2-based gas turbines and fuel cells allow for re-electrification of hydrogen as another means for electricity and gas infrastructure integration. The focus of the underlying analysis is, however, on underground hydrogen storage as major objective of the project. Therefore, the model explicitly distinguishes between salt caverns and hydrogen storage in porous media such as depleted gas fields or aquifers. Moreover, other aboveground H_2 storage such as pressurised gas tanks are included, yet to a limited extent. The transport infrastructure is mainly based on dedicated hydrogen pipelines, which can either be newly built or retrofitted from existing natural gas infrastructure. Where necessary, predefined relations between selected nodes can also be covered by other transportation means such as hydrogen shipping. In the context of infrastructure modelling, onsite electrolysis is defined as H_2 supply at the same grid node as consumption without the need for H_2 transport.

Finally, it is worth mentioning that all demand figures are considered as exogenous input parameters and are thus not subject to actual system optimization. This is due to the fact that in some sectors end-users‘ behaviour is not necessarily based on pure techno-economic conditions but might take into account also other soft factors and personal preferences such as convenience or environmental image (e.g. when choosing between conventional gasoline/diesel cars, Battery Electric Vehicles - BEVs and Fuel Cell Electric Vehicles - FCEVs). The demand for both energy carriers is subdivided into the following end-user sectors:

- **Industry:** direct power, process heat (electricity and H_2-based) as well as H_2 feedstock consumption in different sub-sectors.
- **Residential & services:** basic power consumption (e.g. by white appliances) and heating needs in buildings, both by electric heat pumps and H_2-based heating appliances.
- **Mobility:** fuel consumption by BEVs and FCEVs.

Note that hydrogen demand may also include potential H_2 injection into the existing natural gas (methane) infrastructure. The methane infrastructure itself is excluded from further analysis as it is not in the major scope of this study.[5]

The model adaptations for the purpose of this study in comparison to the previous versions of the model are threefold:

- **Distinction between different H_2 storage technologies:** in order to analyse the role of the large-scale underground hydrogen storage in porous media in the European energy system, the technological dimension was extended adequately. The model is now capable to make long-term investment and short-term operation decisions simultaneously for different H_2 storage technologies.
- **More detailed mathematical representation of storage technologies:** to model important technical issues of hydrogen underground storage, its mathematical representation has been enhanced in several ways (see also Chapter 3 for more details). First, the objective function includes the variable costs of storage input and output to examine the storage-related costs in more detail. Second, the investment decisions in input/output and storage volume capacities are now independent from each other. Hence, the model provides the optimal ratio between the flow rates and energy-related storage size.
- **Multi-nodal approach for investments in production, storage and transport capacities:** the geographical distribution of storage potential between various Member States is one of the major systematic differences between H_2 storage in porous media and salt caverns. In order to capture this important systemic feature, a fully new modelling step was introduced to optimise investments in H_2 production, storage and transport simultaneously for all grid nodes (see Chapter 1.2 for more details). This model adaptation required on the one hand some major assumptions and simplifications (see Chapter 2 for more details) and on the other hand also the development of new data exchange algorithms for each modelling step.

[5] However, the model is capable of analysing the methane infrastructure in parallel to the hydrogen infrastructure. This constellation has been successfully tested and applied in previous studies, e.g. in Bünger et al. (2018) or Trinomics/LBST/E3M (2019).

1.2. Three-step modelling approach

As depicted in Figure 2, the modelling exercise consists of three consecutive steps. After input data preparation the first step represents solving the capacity expansion problem in respect to energy supply units (e.g. intermittent and dispatchable power plants or electrolysis), energy storage (e.g. stationary batteries for electricity or salt caverns for hydrogen) and corresponding transport infrastructure (i.e. power lines and gas pipelines). In other words, the model makes optimal long-term investment and transport decisions for all elements of the system including energy import capacities given the predefined demand levels in each node and time step. This can be interpreted as optimal power and hydrogen sourcing and trading between e.g. markets, pricing zones or Member States, in case each grid node represents one such market, zone or country. A major constraint of the model is represented by a greenhouse gas (GHG) emission gap which limits the use of fossil fuels within the energy system.

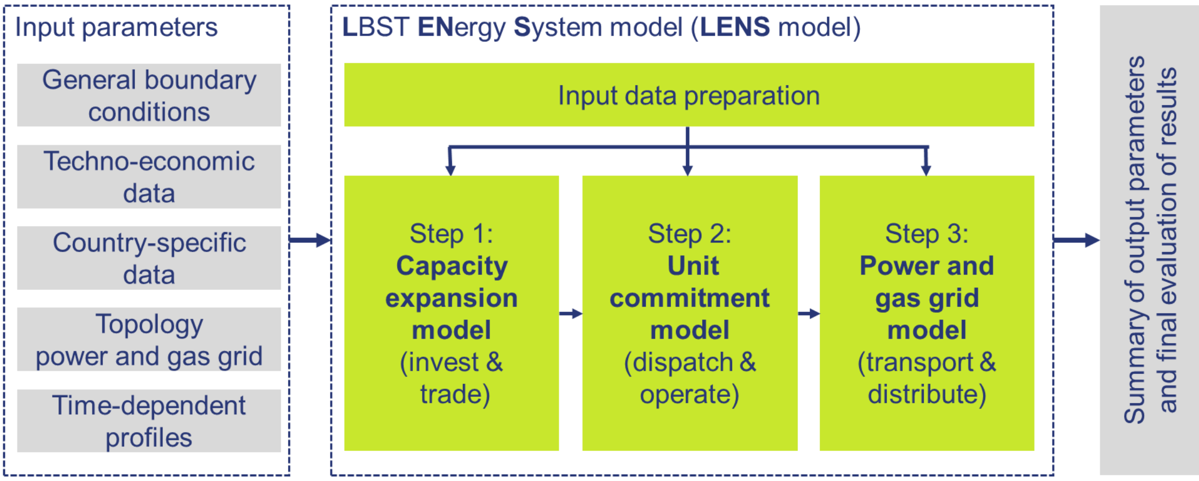

Figure 2: Three-step approach of the LENS model

In the second step the unit commitment model evaluates the optimal scheduling of different system elements in more detail based on the expected capacities from the first modelling step. Typically, the optimization in the second step has a higher temporal resolution (i.e. larger number of time steps) to better represent the variable profiles of power and hydrogen demand as well as of intermittent electricity feed-in. However, the spatial resolutions are usually reduced to a smaller number of nodes to limit the computational efforts. In this way, the simulation can provide more accurate results for short-term dispatching of intermittent and dispatchable power plants as well as for operation of electrolysis and storage technologies at acceptable solving time. Note that for the sake of consistency the modelling exercise in the second step also allows for investments in selected flexibility elements such as peak-load power plants or stationary batteries to balance out variable renewables feed-in and energy demand. The comparison of required capacities between the first and second modelling steps reveals the additional flexibility needs of a system with a high share of renewable energy when using more detailed time series.

In the third step the model focuses on the optimal energy flows and capacity investments in transport infrastructure between the different nodes based on the expected capacities and operations schedule of all other system elements from the previous modelling steps. In order to reduce computational burden, the temporal and spatial dimensions are mainly decoupled from each other in two ways. First, the installed production and storage capacities from the first and second modelling steps are fixed and distributed to the different nodes according to a predefined allocation key. Second, the optimal unit dispatching and operation from the second modelling step are combined together with the demand resulting in a residual load again allocated to each node as an exogenous input parameter. Hence, the underlying problem is simplified to decision making on optimal quantities and capacities for power and hydrogen transport between the grid nodes. Nevertheless, some flexibility to the system is provided by limited additional re-dispatching potential in each grid node in order to improve the utilisation of single lines and to ensure an economic operation of the infrastructure.

Finally, after the modelling exercise the output parameters from all steps are summarized and evaluated in an adequate way to provide the relevant findings in line with the individual study objective. As illustrated in Figure 2 the input parameters include:

- **General boundary conditions** such as fuel and carbon prices, discount rates, GHG emission and curtailment limits, etc.
- **Techno-economic data:** costs, efficiency, sizing ratios, lifetime, etc. for each technology.
- **Country-specific data:** power and hydrogen demand as well as installed capacities and investment limits for different technologies per country.
- **Topology of power and gas grid:** existing transport capacities, costs, efficiencies and investment limits for transport infrastructure between the selected grid nodes.
- **Time-dependent profiles:** normalised time series for country-specific power and hydrogen demand as well as technology-specific minimal and maximal production limits.

2. Major assumptions and limitations

2.1. Market structure assumptions

The approach of system cost minimization within the LENS modelling framework corresponds either to centralized system planning by a neutral regulator or to perfect competition between market participants under symmetric information and without any market power and additional transaction costs. The model implicitly assumes that there is only one wholesale energy market for all activities related to power and hydrogen supply, conversion, storage and transport.

In reality, there are multiple energy markets in terms of service provision (e.g. different wholesale markets with various time horizons or balancing markets for grid services) and in terms of geographical scope (i.e. different bidding zones for selected countries or regions). In this context, according to some authors such as e.g. Sioshansi (2011) or Teng & Strbac (2016) limiting storage use to only selected applications or markets might underestimate its overall value. In addition, the interlinkage between the electricity and gas markets and infrastructures is still weak and does not correspond to a fully integrated market. In fact, hydrogen market, mainly organised in a business-to-business manner within the industry sector[6], is strongly segmented without a common and transparent marketplace and publicly accessible transport infrastructure.

However, the major objective of this study is to compare different hydrogen underground storage technologies. Applying only one energy market as a common boundary condition will still provide a fair comparison of the selected technologies while reducing the modelling complexity. Moreover, from the more general perspective, separate power, hydrogen and natural gas markets hinder an effective energy system coordination. The need for interlinked energy system planning has been recognized in a number of studies, e.g. by Deane et al. (2017) or Illinois Institute of Technology (2015) as well as by the EU Regulation No 347/2013 on guidelines for trans-European energy infrastructure. As a consequence, both ENTSO-E and ENTSOG have developed a first common interlinked model (see ENTSOG and ENTSO-E 2016), to be further enhanced by the results from Artelys (2018). Hence, in the light of the attempt to develop common planning tools in the narrower sense and to establish an internal energy market within the Energy Union in the broader sense, modelling fully integrated, transparent and efficient power and hydrogen markets appears to be a realistic approach in the long-term.

2.2. Limitations on temporal and spatial resolution

Another important model assumption and limitation is related to the time dimension in two ways. First, the simulation assumes perfect foresight for energy demand and renewable feed-in for all hours within a prototypical year for the entire time horizon. Hence, the investment

[6] According to Hydrogen Europe (2021) and Fuel Cell Hydrogen Observatory (2021), 60%-70% of H_2 supply can be categorised as “captive hydrogen production on-site used exclusively for own consumption within the same facility.”

and operation decisions are based on a specific weather year for all time steps. Second, the temporal and spatial resolution differs between the modelling steps leading to the loss of information and suboptimal results to some extent. In reality, optimal investments and operation decisions depend on a broad range of complex systemic circumstances and uncertainties such as weather conditions, planned and unplanned production outages, consumer behaviour, fuel prices as well as technology and policy developments, etc., which can be hardly predicted and implemented in one single model.

In fact, a number of publications recognise the computational burden and thus the need for simplification when dealing with investment and operation decisions of energy storage especially under increasing share of intermittent power feed-in (see e.g. Kannan & Turton 2013, Frew & Jacobson 2016, Pineda & Morales 2018 or Radu et al. 2021). Therefore, as reviewed by Hoffmann et al. (2020), different techniques such as down-sampling, averaging or clustering can be applied to reduce time resolution and thus model complexity in order to achieve a satisfactory trade-off between results accuracy and solving time.

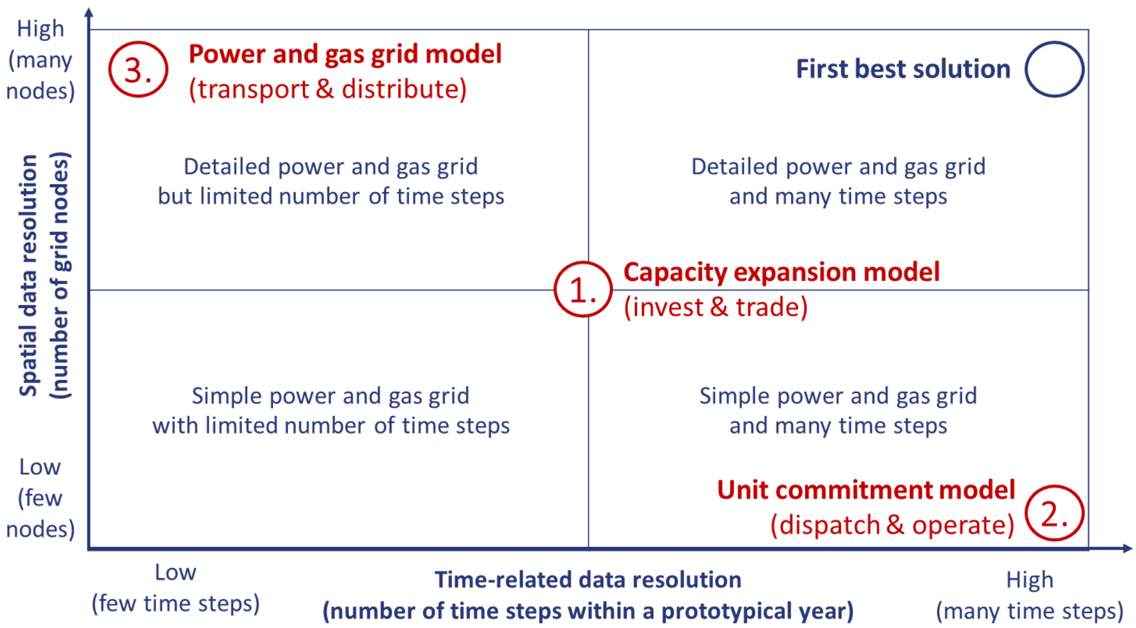

Figure 3: Trade-offs to reduce model complexity and computational load

The general approach of the LENS model in this context is illustrated in Figure 3. In order to solve the capacity expansion problem in the first modelling step, the number of time steps has to be reduced significantly (e.g. to 120 periods per year) while maintaining a sufficiently large spatial resolution (e.g. one node might represent one Member State). In this way the optimization routine allows for investment decisions in all technologies for every node (e.g. Member States) taking into account the daily, weekly, monthly and seasonal patterns. Such profiles can be considered as sufficient to describe major system characteristics relevant for large-scale underground hydrogen storage. However, this approach might underestimate the short-term flexibility needs of a system with increasing share of renewable generation. In contrast, the accuracy of the second modelling step is driven by detailed demand and feed-in profiles (e.g. on an hourly basis) but the spatial dimension is reduced to only one or few nodes representing one or few bidding zones or wholesale markets. Neglecting such grid constraints might lead to suboptimal requirements for grid extension and thus potential underutilisation of singe lines in the next modelling step.[7]

Finally, the third modelling step represents a more detailed power and hydrogen grid simulation with maximal number of nodes. Thanks to decoupling of the temporal and spatial dimensions (see Chapter 1.2) the grid analysis can be conducted for each time step (e.g. for each hour of the year) separately in an efficient way. Nevertheless, the distribution of production and storage capacities according to a predefined allocation key might be insufficient from the entire system perspective leading to undesirable energy flows and grid extensions.

In general, this approach follows the design of today's energy markets according to different horizons for decision making. First, the long-term investment decisions in different locations are based on expected market outcomes and network boundary conditions at a more aggregated level. Then the subsequent unit dispatching and operation relays on the short-term outcomes (in the power market typically on an hourly basis) on a spot market which in future might be represented by one internal discrimination-free marketplace in line with the principles of the Energy Union. Finally, the optimal grid operation and extension follows the needs of the spot market given predefined techno-economic constraints. In this way, the LENS model can reduce the computational load significantly while taking into account most important characteristics of the energy system from the storage perspective. The short solving time allows also to run a number of sensitivity analyses which can capture the uncertainties related to different weather years and short-term fluctuation of demand and renewable feed- in.

2.3. Technology-related limitations

Additional model limitations are related to the representation of different technologies. The analysis typically only accounts for various technology types instead of detailed technical representation of single units. This means that for example hydrogen storage in porous media is represented by one technology type with average characteristics (cost, efficiency, etc.) instead of single units with site-specific techno-economic data. Moreover, some of engineering details such as ramping behaviour of power and hydrogen production or techno-economic constraints of sub-units (e.g. compressors attached to low pressure electrolysis) are neglected to improve computational tractability (see also mathematical representation of the model in Chapter 3). In reality, there might be site-specific engineering boundary conditions for each facility with individual technological specifications such as microbial activity for H_2 storage in porous media. Hence, the modelling results can be interpreted as average output for standard units in each grid node. Further sensitivity analyses might be useful to test the impact of different techno-economic assumptions on the overall modelling outcome.

[7] This could be avoided by separate flexibility planning for each individual node or by modelling the first best solution with maximal temporal and spatial resolution. However, both approaches would require large computational resources potentially becoming intractable especially for the latter case.

3. Mathematical representation

The mathematical representation of the adapted version of the LENS model for the analysis in this study is presented in Equations (1) - (32). Note that the general structure of the model remains unchanged for all modelling steps. The different scope of each modelling step is achieved by modifying the index elements (i.e. by changing the number of nodes and time steps) and relevant input parameters (i.e. excluding some non-negative decisions variables through putting maximal values to zero or by updating the demand parameters). Chapter 4 contains an overview of all indices, input parameters and decision variables.

As mentioned in Chapter 1.1 the model minimises the total system cost (*TSC*) under the LP framework as described by the objective function in Equation (1). The total system cost account for all cost associated with investments and operation of each production unit $p \in P$, storage technology $s \in S$ and power and hydrogen transport in each grid node $n \in N$ and time step $t \in T$. In particular it includes the following components:

- annuity-based cost of capacity increase and fixed cost for overall installed capacities (i.e. initial capacity plus investments) in line 1, 2, 4 and 6 of Equation (1) and
- variable cost for production, storage input (injection) and output (withdrawal), transport between different grid nodes as well as re-dispatch cost related to both energy carriers taking into account the constant load duration *ld* of each time period in line 1, 3, 5 and 7 of Equation (1).

$$
\begin{aligned}
\min TSC =& \sum_p \sum_n \left[a_p I_{p,n} + fc_p \left(K_{p,n} + I_{p,n} \right) + ld \cdot vc_p \sum_t q_{p,n,t}^{prod} \right] \\
&+ \sum_s \sum_n a_s^V I_{s,n}^V + a_s^F I_{s,n}^F + fc_s^V \left(K_{s,n}^V + I_{s,n}^V \right) + fc_s^F \left(K_{s,n}^F + I_{s,n}^F \right) \\
&+ ld \sum_s \sum_n \sum_t \left(vc_s^{in} q_{s,n,t}^{in} + vc_s^{out} q_{s,n,t}^{out} \right) \\
&+ \sum_n \sum_m a_{n,m}^{EL} I_{n,m}^{EL} + fc_{n,m}^{EL} \left(K_{n,m}^{EL} + I_{n,m}^{EL} \right) \\
&+ ld \sum_n \left[rc^{EL} \left(r_{n,t}^{EL\uparrow} + r_{n,t}^{EL\downarrow} \right) + \sum_m \sum_t vc_{n,m}^{EL} f_{n,m,t}^{EL} \right] \\
&+ \sum_n \sum_m a_{n,m}^{H2} I_{n,m}^{H2} + fc_{n,m}^{H2} \left(K_{n,m}^{H2} + I_{n,m}^{H2} \right) \\
&+ ld \sum_n \left[rc^{H2} \left(r_{n,t}^{H2\uparrow} + r_{n,t}^{H2\downarrow} \right) + \sum_m \sum_t vc_{n,m}^{H2} f_{n,m,t}^{H2} \right]
\end{aligned}
\tag{1}
$$

The minimization problem is subject to techno-economic constraints as described in Equations (2) to (32). The production quantities in Equation (2) and (3) are bounded by minimal and maximal profiles depended on the overall capacity. Moreover, the production is restricted by the overall CO_2 emission cap in Equation (4) and investments by the maximal capacity increase in Equation (5). In this way the model accounts for the availability of renewable feed-in and potential must-run capacities of the power plants while limiting the CO_2 emission and potential investment trajectories for selected technologies (e.g. trajectories for renewables increase or phase out of coal power plants).

$$q_{p,n,t}^{prod} \geq p_{p,n,t}^{min}\left(K_{p,n} + I_{p,n}\right) \qquad \forall\, p \in P, n \in N, t \in T \qquad (2)$$

$$q_{p,n,t}^{prod} \leq p_{p,n,t}^{max}\left(K_{p,n} + I_{p,n}\right) \qquad \forall\, p \in P, n \in N, t \in T \qquad (3)$$

$$ld \cdot \sum_p \sum_t \varepsilon_p q_{p,n,t}^{prod} \leq CAP_n^{CO2} \qquad \forall\, n \in N \qquad (4)$$

$$I_{p,n} \leq \bar{I}_{p,n} \qquad \forall\, p \in P, n \in N \qquad (5)$$

The constrains related to the energy storage are described in Equation (6) to (11). According to Equation (6) the storage level *L* of a specific storage technology *s* in a given period *t* of a given node *n* equals storage level from the previous period plus storage input (injection) reduced by storage output (withdrawal). Storage operation is restricted by both volume capacity and maximal capacities for flow rates in Equations (7) and (8), respectively. The investments in storage capacities are further constrained by maximal capacity increase representing the storage potential in the selected node as well as by the technology-specific volume to flow rate ratio as represented in Equations (9) to (11), respectively.

$$L_{s,n,t} = L_{s,n,t-1} + ld \cdot \left(q_{s,n,t}^{in} - q_{s,n,t}^{out}\right) \qquad \forall\, s \in S, n \in N, t \in T \qquad (6)$$

$$L_{s,n,t} \leq K_{s,n}^{V} + I_{s,n}^{V} \qquad \forall\, s \in S, n \in N, t \in T \qquad (7)$$

$$q_{s,n,t}^{in} + q_{s,n,t}^{out} \leq K_{s,n}^{F} + I_{s,n}^{F} \qquad \forall\, s \in S, n \in N, t \in T \qquad (8)$$

$$I_{s,n}^{F} \leq \bar{I}_{s,n}^{F} \qquad \forall\, s \in S, n \in N \qquad (9)$$

$$I_{s,n}^{V} \leq \bar{I}_{s,n}^{V} \qquad \forall\, s \in S, n \in N \qquad (10)$$

$$I_{s,n}^{V} \leq \theta_{s,n} \cdot I_{s,n}^{F} \qquad \forall\, s \in S, n \in N \qquad (11)$$

Demand side management (DSM) is modelled in a similar way as storage technologies. Additional constraints in Equations (12) and (13) ensure that shifting energy between the time steps remains within the predefined delay time δ_s.

$$L_{s,n,t} \leq \sum_{\tau=t-\delta_s}^{t} q_{s,n,\tau}^{in} \qquad \forall\, n \in N, t \in T, s = DSM \qquad (12)$$

$$L_{s,n,t} \leq \sum_{\tau=t+1}^{t+\delta_s} q_{s,n,\tau}^{out} \qquad \forall\, n \in N, t \in T, s = DSM \qquad (13)$$

Equations (14) and (15) describe power and hydrogen balance, respectively, in each grid node. The left side of Equation (14) and (15) represents energy input consisting of the overall energy production, storage output (withdrawal), energy transport flows from other grid nodes to the given node *n* and potential production increase or consumption decrease through re-dispatch.

Note that power consumption coefficients pf_p^{EL} and pf_p^{H2} allow to control the type of energy output of a production unit *p*. For all power plants both pf_p^{EL} and the electrical efficiency η_p^{EL} are set to 1 and each unit's energy input equals $q_{p,n,t}^{prod}$ in a given power grid node *n* at time step *t*. Only in case of hydrogen-based power plants (e.g. H_2 gas turbines) $pf_p^{H2} = -1$ and $\eta_p^{H2} \leq 1$ to ensure hydrogen consumption according to the corresponding efficiency while otherwise $pf_p^{H2} = 0$. In contrast, for electrolysis $pf_p^{EL} = -1$ and $\eta_p^{EL} \leq 1$ which corresponds to power consumption and $pf_p^{H2} = 1$ and $\eta_p^{H2} = 1$ indicating hydrogen production in the given hydrogen grid node *n*.

In case of energy storage technologies, the efficiency coefficients $\eta_s^{EL\,in}$, $\eta_s^{EL\,out}$ and $\eta_s^{H2\,in}$, $\eta_s^{H2\,in}$ can be used to define pure hydrogen and power storage, respectively, by setting the corresponding parameters to zero. Note that otherwise on the one hand $0 < \eta_s^{EL\,out} \leq 1$ and $0 < \eta_s^{H2\,out} \leq 1$ and on the other hand $\eta_s^{EL\,in} \geq 1$ and $\eta_s^{H2\,in} \geq 1$ to account for potential losses associated with storage withdrawal and injection, respectively, for most of the storage technologies. The only exception is represented by the DMS where storage injection corresponds to demand decrease and storage withdrawal to demand increase in a given time step *t*. Hence, all efficiency coefficients $\eta_s^{EL\,in}$, $\eta_s^{EL\,in}$, $\eta_s^{H2\,in}$, $\eta_s^{H2\,out}$ equal -1 for demand side management.

The right side of Equations (14) and (15) corresponds to power and hydrogen output, respectively, including the energy demand as described in Equation (24) and (25), storage input (injection), energy transport from the given node *n* to all other nodes as well as production decrease or consumption increase through re-dispatch.

$$ld\left(\sum_p\left(\frac{pf_p^{EL}}{\eta_p^{EL}}q_{p,n,t}^{prod}\right)+\sum_s\left(\eta_s^{EL\,out}q_{s,n,t}^{out}\right)+\sum_m\left(\eta_{m,n}^{EL}f_{m,n,t}^{EL}\right)+r_{n,t}^{EL\uparrow}\right)$$
$$=D_{n,t}^{EL}+ld\left(\sum_s\left(\eta_s^{EL\,in}q_{s,n,t}^{in}\right)+\sum_m\left(\eta_{n,m}^{EL}f_{n,m,t}^{EL}\right)+r_{n,t}^{EL\downarrow}\right)$$
$$\forall\, n \in N,\ t \in T \qquad (14)$$

$$ld\left(\sum_p\left(\frac{pf_p^{H2}}{\eta_p^{H2}}q_{p,n,t}^{prod}\right)+\sum_s\left(\eta_s^{H2\,out}q_{s,n,t}^{out}\right)+\sum_m\left(\eta_{m,n}^{H2}f_{m,n,t}^{H2}\right)+r_{n,t}^{H2\uparrow}\right)$$
$$=D_{n,t}^{H2}+ld\left(\sum_s\left(\eta_s^{H2\,in}q_{s,n,t}^{in}\right)+\sum_m\left(\eta_{n,m}^{H2}f_{n,m,t}^{H2}\right)+r_{n,t}^{H2\downarrow}\right)$$
$$\forall\, n \in N, t \in T \qquad (15)$$

Furthermore, the Equations (16) to (19) describe maximal power and hydrogen transport flows and investments in transport capacities between different grid nodes *n* and *m*. Re-dispatch is constrained by available capacities as indicated in Equations (20) to (23).

$$f_{n,m,t}^{EL} \leq K_{n,m}^{EL} + I_{n,m}^{EL} \qquad \forall\, n \in N, t \in T \qquad (16)$$

$$f_{n,m,t}^{H2} \leq K_{n,m}^{H2} + I_{n,m}^{H2} \qquad \forall\, n \in N, t \in T \qquad (17)$$

$$I_{n,m}^{EL} \leq \bar{I}_{n,m}^{EL} \qquad \forall\, n \in N \qquad (18)$$

$$I_{n,m}^{H2} \leq \bar{I}_{n,m}^{H2} \qquad \forall\, n \in N \qquad (19)$$

$$r_{n,t}^{EL\uparrow} \leq K_{n,t}^{EL\uparrow} \qquad \forall\, n \in N, t \in T \qquad (20)$$

$$r_{n,t}^{EL\downarrow} \leq K_{n,t}^{EL\downarrow} \qquad \forall\, n \in N, t \in T \qquad (21)$$

$$r_{n,t}^{H2\uparrow} \leq K_{n,t}^{H2\uparrow} \qquad \forall\, n \in N, t \in T \qquad (22)$$

$$r_{n,t}^{H2\downarrow} \leq K_{n,t}^{H2\downarrow} \qquad \forall\, n \in N, t \in T \qquad (23)$$

The total power and hydrogen demand D in Equations (24) and (25), respectively, include the actual node-specific demand per relevant sector multiplied by the corresponding normalised time profiles.

$$D_{n,t}^{EL} = d_{n,t}^{Basic} p_{n,t}^{Basic} + d_{n,t}^{BEV} p_{n,t}^{BEV} + d_{n,t}^{HP} p_{n,t}^{HP} \qquad \forall\, n \in N,\; t \in T \qquad (24)$$

$$D_{n,t}^{H2} = d_{n,t}^{Ind} p_{n,t}^{Ind} + d_{n,t}^{FCEV} p_{n,t}^{FCEV} + d_{n,t}^{Heat} p_{n,t}^{Heat} \;\forall\, n \in N, t \in T \qquad (25)$$

Finally, all decision variables are non-negative as postulated in Equations (26) to (32).

$$q_{p,n,t}^{prod} \geq 0 \qquad \forall\, p \in P, n \in N, t \in T \qquad (26)$$

$$q_{s,n,t}^{in} \geq 0; \quad q_{s,n,t}^{out} \geq 0\,; \; L_{s,n,t} \geq 0 \qquad \forall\, s \in S, n \in N, t \in T \qquad (27)$$

$$f_{n,m,t}^{EL} \geq 0\,; \; f_{n,m,t}^{H2} \geq 0 \qquad \forall\, n \in N, t \in T \qquad (28)$$

$$r_{n,t}^{EL\uparrow} \geq 0\,; \quad r_{n,t}^{EL\downarrow} \geq 0\,; \; r_{n,t}^{H2\uparrow} \geq 0\,; \; r_{n,t}^{H2\downarrow} \geq 0 \quad \forall\, n \in N, t \in T \qquad (29)$$

$$I_{p,n} \geq 0 \qquad \forall\, p \in P, n \in N \qquad (30)$$

$$I_{s,n}^{F} \geq 0\,; \; I_{s,n}^{V} \geq 0\,; \qquad \forall\, s \in S, n \in N \qquad (31)$$

$$I_{n,m}^{EL} \geq 0\,; \; I_{n,m}^{H2} \geq 0 \qquad \forall\, n \in N \qquad (32)$$

4. Nomenclature of the LENS model

4.1. Sets and indices

T, t, τ Set and indices of time periods in a prototypical year

P, p Set and index of production technologies

S, s Set and index of storage technologies

N, n, m Set and index of grid nodes

4.2. Input parameters

4.2.1. Demand related parameters

Parameter	Description
$D_{n,t}^{EL}$	Total power demand
$d_{n,t}^{Basic}$	Basic power demand (white appliances, industry, etc.)
$d_{n,t}^{BEV}$	Power demand in the mobility sectors
$d_{n,t}^{HP}$	Power demand in buildings sector (heat pumps)
$D_{n,t}^{H2}$	Total hydrogen demand
$d_{n,t}^{Ind}$	Hydrogen demand in industry sector
$d_{n,t}^{FCEV}$	Hydrogen demand in mobility sector
$d_{n,t}^{Heat}$	Hydrogen demand in buildings sector (H_2 heating)
CAP_{n}^{CO2}	CO_2 emission cap

4.2.2. Time series parameters

Parameter	Description
$p_{n,t}^{Basic}$	Normalised time series for basic power demand
$p_{n,t}^{BEV}$	Normalised time series for power demand in the mobility sector
$p_{n,t}^{HP}$	Normalised time series for power demand for heat pumps
$p_{n,t}^{Ind}$	Normalised time series for H_2 demand in industry sector
$p_{n,t}^{FCEV}$	Normalised time series for H_2 demand in mobility sector
$p_{n,t}^{Heat}$	Normalised time series for H_2 heating demand
$p_{p,n,t}^{min}$	Normalised minimal production profile
$p_{p,n,t}^{max}$	Normalised maximal production profile
ld	Load duration for each time period

4.2.3. Technical parameters

Parameter	Description
pf_p^{EL}	Power consumption coefficient of a production unit
η_p^{EL}	Efficiency related to power output of a production unit
pf_p^{H2}	Hydrogen consumption coefficient of a production unit
η_p^{H2}	Efficiency related to hydrogen output of a production unit
ε_p	Specific CO_2 emissions from power or H_2 production
$\eta_s^{EL\ in}$	Efficiency coefficient for power storage input (injection)
$\eta_s^{EL\ out}$	Efficiency coefficient for power storage output (withdrawal)
$\eta_s^{H2\ out}$	Efficiency coefficient for hydrogen storage input (injection)
$\eta_s^{H2\ in}$	Efficiency coefficient for hydrogen storage output (withdrawal)
$\theta_{s,n}$	Maximal ratio between storage volume and flow rate
δ_s	Delay time for demand side management
$\eta_{n,m}^{EL}$	Power transport efficiency between two nodes
$\eta_{n,m}^{H2}$	Hydrogen transport efficiency between two nodes

4.2.4. Economic parameters

Parameter	Description
a_p	Annuity for increase of production capacity
a_s^V	Annuity for increase of storage volume capacity
a_s^F	Annuity for increase of storage input/output capacity
$a_{n,m}^{EL}$	Annuity for increase of power transport capacity
$a_{n,m}^{H2}$	Annuity for increase of hydrogen transport capacity
fc_p	Fixed costs per production capacity
fc_s^V	Fixed costs per storage volume capacity
fc_s^F	Fixed costs per storage input/output capacity
$fc_{n,m}^{EL}$	Fixed costs per power transport capacity
$fc_{n,m}^{H2}$	Fixed costs per hydrogen transport capacity
vc_p	Variable production cost
vc_s^{in}	Variable storage input (injection) cost
vc_s^{out}	Variable storage output (withdrawal) cost
$vc_{n,m}^{EL}$	Variable power transport cost
$vc_{n,m}^{H2}$	Variable hydrogen transport cost
$rc_{n,m}^{EL}$	Variable cost for power supply changes through re-dispatch
$rc_{n,m}^{H2}$	Variable cost for H_2 supply changes through re-dispatch

4.2.5. Capacity related parameters

Parameter	Description
$K_{p,n}$	Installed production capacity
$K_{s,n}^{V}$	Installed storage volume capacity
$K_{s,n}^{F}$	Installed storage input/output (injection/withdrawal) capacity
$K_{n,m}^{EL}$	Installed power transport capacity between two nodes
$K_{n,m}^{H2}$	Installed hydrogen transport capacity between two nodes
$K_{n,t}^{EL\uparrow}$	Max. capacity for power supply increase through re-dispatch
$K_{n,t}^{EL\downarrow}$	Max. capacity for power supply decrease through re-dispatch
$K_{n,t}^{H2\uparrow}$	Max. capacity for H_2 supply increase through re-dispatch
$K_{n,t}^{H2\downarrow}$	Max. capacity for H_2 supply decrease through re-dispatch
$\bar{I}_{p,n}$	Maximal investment in production capacity
$\bar{I}_{s,n}^{V}$	Maximal investment in storage volume capacity
$\bar{I}_{s,n}^{F}$	Maximal investment in storage input/output capacity
$\bar{I}_{n,m}^{EL}$	Maximal investment in power transport capacity
$\bar{I}_{n,m}^{H2}$	Maximal investment in hydrogen transport capacity

4.3. Decision variables

Variable	Description
$q_{p,n,t}^{prod}$	Production quantity
$q_{s,n,t}^{in}$	Storage input (injection) quantity
$q_{s,n,t}^{out}$	Storage output (withdrawal) quantity
$L_{s,n,t}$	Storage level
$f_{n,m,t}^{EL}$	Power flow (transport) quantity between two nodes
$f_{n,m,t}^{H2}$	Hydrogen flow (transport) quantity between two nodes
$r_{n,t}^{EL\uparrow}$	Power supply increase through re-dispatch
$r_{n,t}^{EL\downarrow}$	Power supply decrease through re-dispatch
$r_{n,t}^{H2\uparrow}$	Hydrogen supply increase through re-dispatch
$r_{n,t}^{H2\downarrow}$	Hydrogen supply decrease through re-dispatch
$I_{p,n}$	Investment in production capacity
$I_{s,n}^{V}$	Investment in volume capacity of a storage
$I_{s,n}^{F}$	Investment in input/output capacity of a storage (flow rate)
$I_{n,m}^{EL}$	Investment in power transport capacity between two nodes
$I_{n,m}^{H2}$	Investment in hydrogen transport capacity between two nodes

5. Abbreviations

BEVs	Battery electric vehicles
CCS	Carbon Capture and Storage
CO_2	Carbon dioxide
DSM	Demand side management
EU	European Union
FCEVs	Fuel cell electric vehicles
GHG	Greenhouse gas
H_2	Hydrogen
LENS	LBST ENergy System (model)
LP	Linear programming
PtG	Power-to-Gas
PV	Photovoltaics

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