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Design of Large-Scale Hybrid, Hydrogen and Battery, and Energy Storage Systems for Grid Applications

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ABSTRACT Due to the energy transition, which involves phasing out base load power plants such as coal, there is a need to establish storage systems within the energy system to compensate for fluctuations of renewable energies. Batteries are suitable for day-night cycles and particularly for short-cycle applications. To address the problem of dark-doldrums, when neither wind nor solar energy is available, gas and, in the more distant future, hydrogen power plants are to be used. By combining batteries and hydrogen power plants in a hybrid energy storage system, further advantages and application possibilities arise regarding grid stability and system design. This work illustrates interrelationships between the subsystems, optimizes proportions, and demonstrates logical system sizes, technologies, and their costs. A central part of the work are the self-derived methods for system design and the justification of these. Storage pressure, running times, availability time, annual cycles and design of the subsystems are described. Systems of this scale are difficult to imagine. A program developed as part of this work to implement the methods, visualizes the system, displays the system parameters, and shows the best-case and worst-case capital expenditures. An optimized system design is presented. Different combinations in the system design show the effects on capital expenditures. Starting from 2 to 4 hours of availability time, the hybrid system becomes cheaper than a pure battery system in terms of capital expenditures.

INDEX TERMS Hybrid energy storage system, H2-gas-turbine, dark doldrums, ancillary services, system design.

I. INTRODUCTION

BATTERY energy storage systems (BESS) are increasingly being integrated into the grid infrastructure to deliver ancillary services and power control, which are traditionally provided by conventional energy sources such as coal-fired power plants. The challenge for these systems lies in the fact that the costs of BESS are closely linked to the amount of energy that can be stored [1]. One solution for this could be to extend these BESS with a hydrogen power loop, in combination called hybrid energy storage system (HESS). The system includes then a BESS, an Electrolyzer (EL), a hydrogen gas storage and a hydrogen gas turbine (GT). Figure 1 shows the schematic design of this system. The BESS is responsible for rapid grid feed-in, as can be seen in Figure 2. While the BESS provides energy immediately, the gas turbine requires time to start. The total power output, consisting of P_{gt} and P_{batt}, must always sum up to the required power, here referred as P_{target}. The hydrogen storage decouples costs from the energy quantity. Gas turbines are preferable for systems the size of a power plant. Due to the size of the overall system, the concept is integrated into the high-voltage system.

Here, we propose an integrative (holistic) optimization methodology that is implemented in the Hybrid Hydrogen and Battery Storage Levelized Design Application-Tool (HHyLDA-Tool).

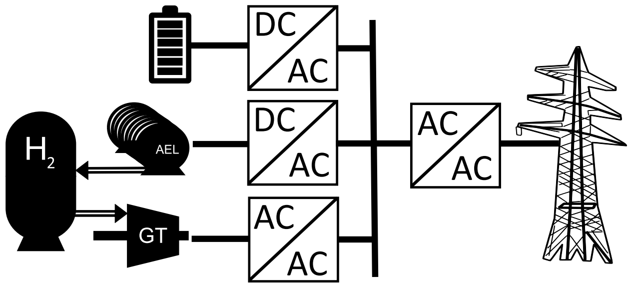

FIGURE 1. Schematic representation of a hybrid energy storage system combining large battery storage, electrolyzer, H_2 gas storage, and H_2 gas turbine integrated into the high-voltage grid.

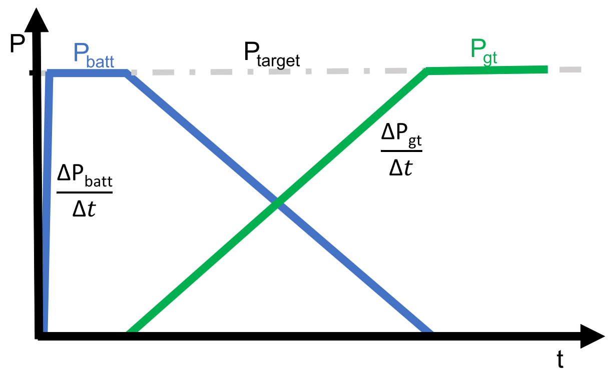

FIGURE 2. Schematic power-time diagram for the transition of BESS for short-term grid injection, which is replaced by the gas turbine, maintaining a constant total output power P_{target}.

The tool provides simple methods for describing an initial design of the system, initial costs, and the size or dimensions of the system. The methods serve to define parameters needed for system design. Natural and logical boundaries are defined and clarified, emphasizing the optimization potential of these elements. Specifically, system pressure, BESS, annual operating hours (cycles), availability (run time, t_{av}) and EL size are optimized or described. In particular, the relationships between these individual subsystems and parameters are highlighted. Availability is determined on the basis of the dark doldrums problem, while the required dynamics and the minimum electrolyzer size are derived from the Grid Code. An energy balance is established to determine the electrolyzer and BESS size. The HHyLDA-Tool calculate optimizations directly, providing information on capital expenditures (CAPEX) and then compare various business cases. Several design tools for hybrid hydrogen and battery storage systems can be found in the literature. Some of them develop complete models for each subsystem, requiring significant effort for system design, as seen in Ancona et al. [2]. Often, components such as batteries are simply determined by the available systems on the market [3]. Mostly, smaller systems are designed on a kW scale [2], [3]. In-depth optimization problems are described [4].

A significant focus in the literature is on systems designed purely for energy storage, where the fast response requirements dictated by grid codes are not a concern, and the battery is used primarily to shift the energy output over time [5].

Here, a completely different approach is used, as the point of view is from the Grid-side. A specific power output is defined, and all other parameters are then calculated using a few equations. The HHyLDA-Tool primarily provides an overall system design, including initial costs, land use, an overview of the appearance, and subsystem size on the scale of the power plant / grid.

This goes beyond the state-of-the-art as all the mentioned aspects are considered in the dimensioning of the power plant, in which the definitions of the Grid Code are also taken into account. The following presents a comprehensive review of the literature on various HESS, their design, and their application areas.

II. LITERATURE REVIEW

Numerous studies have already been published on hybrid systems and their potential benefits or impacts [6], [7] [8]. Many of them focus on island grid applications or microgrids [9], [10] [11], which significantly differs from this work, where network integration plays a crucial role. The consideration of small grid-connected HESS for households has been adequately described and documented [12], [13]. These cannot be directly compared in many aspects since participation in the control reserve market is only permitted for systems exceeding 1 MW, a capacity that household systems do not reach [14]. Often, directly renewable energies are integrated into these systems [6], [10], [11], [12]. This work focuses on a grid-friendly HESS that is not directly coupled to a renewable energy source to optimize its generation. Instead, it is considered from the perspective of the transmission system operator (TSO) as an element that complements the entire balancing group and is therefore described on the scale of a power plant. Specifically, the parameters in system design, individual component optimizations, and the required energy provision using the methods presented in this work could not be located. In a study, Colbertaldo et al. [15] discuss the impact of hydrogen on the electricity power system. The authors describe hydrogen as a promising technology for achieving a 100 % CO_2-neutral high-voltage power supply. They also, assume a wide expansion of renewable energy sources (RES) in the following years and use a Power-to-Power approach with EL, underground storage and fuel cells. Furthermore, it is shown in a preliminary economic analysis that the CAPEX of such systems are massively lower compared to a fully BESS-based grid supported system with 100 % RES [15]. The integration of large-scale storage into the high-voltage grid has significantly increased only in recent years [16], [17]. In Northeast China in recent years, the issue has arisen that surplus energy is generated through photovoltaics when loads are too low. In light of the current expansion rates and goals, this could also happen in Germany. Today, companies like EnBW AG are already starting to set up open-space photovoltaics exclusively with BESS [18], as midday peaks lower market prices and higher yields can be generated towards the evening. Storage systems are thus becoming increasingly integral elements of the energy transition, especially in Germany. Song et al. [19] conclude that HESS can increase the profitability of photovoltaic installations since PV systems do not need to be curtailed, and hydrogen can be produced. A promising EU-funded project is the H2FUTURE project at the Linz steelworks, where a 6 MW proton exchange membrane (PEM) EL was installed in partnership with Siemens Energy. As part of the project, this EL was tested for various operating modes. Among other uses, it was also employed to participate in the power control energy market [20], [21], [22]. In use case 3 of H2FUTURE the use of EL for automatic frequency restoration reserve (aFRR), manual Frequency Restoration Reserve (mFRR) and tertiary control is described. In summary, projects are emerging worldwide that implement HESS and hydrogen is becoming an increasingly important factor. As the share of RES increases, the proportion of storage capacity must also rise. The increasing scale, integration into the high-voltage grid, and combination within entire regions as producers or consumers pose new requirements. Utilizing hybrid systems for grid stabilization in countries, along with hydrogen-capable power plants, will require additional pioneering work in the future. The unique position of a hybrid booster system for short-term grid support to avoid grid expansion represents another potential application [23], [24].

III. METHODS—PARAMETER DETERMINATION

The following section describes the purpose of different parameters and how they can be derived for large scale hybrid hydrogen and battery storage systems for several use cases. Subsequently, an example is provided for a specific system design. The different self-derived methods use various databases for the design and determination of individual parameters [17], [25], [26]. For the examples, data from the German electricity market is used [25]. However, the methods can be applied to any regions to determine the parameters.

A. PARAMETER: LEVELIZED COSTS - CAPEX

For an estimation of the costs and the creation of a database for the HHyLDA-Tool, various studies are cited, and offers were obtained. This is necessary to represent the costs and different business cases. All sources are listed in Table 1 and Table 2 and the data can be found on [25].

Method: An overview of cost ranges between best-case and worst-case scenarios is first generated. The best-case scenarios are considered optimistic future prices, while the worst-case scenarios are more reflective of current prices. The authors decide to use € / kWh to calculate the costs of the BESS. This approach is chosen because levelized costs for batteries are typically higher when expressed per kWh rather than per kW [1]. As a result, the calculations are more conservative and more reference sources are available. Since most current battery projects tend to focus on C-Rates below 1, prices are given in €/kWh. The share of costs for power electronics, additional capacity due to higher losses from increased C-Rates, and thermal management rises proportionally with higher C-Rates. Therefore, this should always be considered within the scope of this study. For C-Rates significantly higher than 1, additional safety margins in terms of energy capacity may be included, even though the price decline in the battery market tends to move in the opposite direction. Additionally, the broad price range accounts for different C-Rates within realistic scenarios. At this point, it should be noted that actual project costs are likely higher as stated here, as planning, project development, construction, and property costs are not yet included. The CAPEX only includes the system costs of the subsystems.

TABLE 1. Estimated prices for hydrogen storage technologies, based on studies and quotations obtained from companies.

Storage Type	[€/m^3]	[€/kg]	Pressure [bar]
Salt caverns [27]	< 200	32-160	70-120
Large cylinder* [28]	2200-3100	400-585	45-150
Pipeline [29]*	2350	380	50-100
Underground pipeing [27]	4346	560	100
MEGC* [28]	11300-15625	493	350
Bottle bundle* [28]	7500-13333	375-500	300
Bottle bundle* [28]	12500-20000	400	500

*Cost estimation through offerings

TABLE 2. Summary of the CAPEX interpretation of the subsystems based on obtained offers and various studies.

Sub System	Lvl. Cost best case	Lvl. Cost worst case	Unit	Sources
BESS*	150	420	€/kWh	[30][31][32][33][15][34][35]
OCGT	450	600	€/kW	[36][37][33][38][39][35]
CCGT	900	1000	€/kW	[36][37][33][38][39][35]
CHP GT	1000	1211	€/kW	[33]
Retrofitting GT	25	89	%	[36][33][37]
Electrolyser (AEL)*	400	830	€/kW	[40][41][42][43]
Electrolyser (PEM)*	500	1300	€/kW	[40][41][42][43]
Electrolyser (AEM)*	436	1196	€/kW	[42][44]
Electrolyser (SOEC)*	1000	4800	€/kW	[45][46][43]
Fuel Cell*	900	1500	€/kW	[47][48][49]

*In Worst-case scenarios, the focus is more on current costs.
Best-case scenarios, on the other hand, are more projections for future scaled markets.

Classification: For a leveled cost estimation, Table 1 presents the results of the literature review and solicited quotes for hydrogen storage technologies. Table 2 shows the results for the remaining subsystems. The determination of the leveled CAPEX is necessary to create the MathWorks®-MATLAB (MATLAB®) application (HHyLDA-Tool) and economically determine the design parameters.

B. PARAMETER: ENERGY OF THE BATTERY STORAGE SYSTEM

The BESS is used in the HESS to provide power immediately, as the GT requires a certain start-up time to deliver power [24].

Method: The transition from BESS supply to GT supply is intended to sustain the grid with consistent power throughout the entire duration. This leads to (1).

$$P_{gt} \equiv P_{batt} \tag{1}$$

Through the general definition of electrical energy, (2) can be described.

$$E_{batt} = P_{batt} \cdot t_{total} \tag{2}$$

Including the ramp rate ($\Delta P/\Delta t$) of the GT, (3) results.

$$E_{batt} = \frac{P_{gt}^2}{\frac{\Delta P}{\Delta t}} \tag{3}$$

By adding the net synchronization time t_{syn} (about 10 min) and a 25 % safety margin for degradation and efficiency to (3), we obtain (4).

$$E_{batt} = \left(P_{gt} \cdot t_{syn} + \frac{P_{gt}^2}{\frac{\Delta P}{\Delta t}}\right) \cdot 1.25 \tag{4}$$

Classification: In contrast to current developments in the BESS market where battery capacities are continually expanding while the power remains constant [32], resulting in a lower C-Rate (≤ 1), the HESS would require a BESS with high power but low capacity. This is because modern GT require a startup time of way less than one hour [50]. The benefit lies in having a smaller capacity, meaning less active material in the cells, thus saving raw materials. Depending on the GT's startup time (e.g 30-60 MW/min [50]), the ideal C-Rate for the system can be calculated. Currently, no BESS with a C-Rate of ≥ 3 in the range of ≥ 100 MW is available. ElectraNet demonstrates in its Dalrymple project in South Australia with a 30 MW and 8 MWh system that systems with a C-Rate of nearly 4 in the MW range are feasible [51]. Larger systems by a factor of 10 with potential higher rates will raise new challenges and need to be developed first.

C. PARAMETER: AVAILABILITY TIME - HYDROGEN STORAGE CAPACITY

A crucial parameter for system design is availability time, which refers to how long the system needs to provide positive power control energy. This minimum quantity is proportional to the operating time of the GT. Firstly, it is important to clarify whether a pipeline connection exists. The GT can operate using either natural gas or pure hydrogen [36]. The EL can feed overproduction into both the gas grid and a H_2 network [52]. Therefore, a gas connection provides flexibility and is recommended. If it is now assumed that a certain storage capacity is required, for example, because there is no pipeline on-site, or it needs to be ensured that the system must guarantee a certain capacity, the question arises of how this size can be derived.

Method: One approach to determining a minimum runtime would be to consider periods of low RES output, known as "dark doldrums", as during these times electricity from RES becomes scarce. The threshold that must be undershot

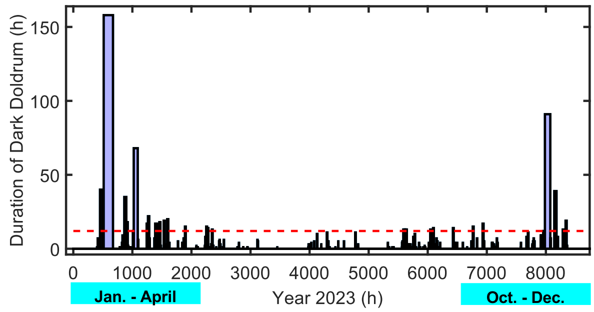

FIGURE 3. **Visualization of the duration of Dark Doldrums from the year 2023 when the generation of RES is below 35 % in germany.**

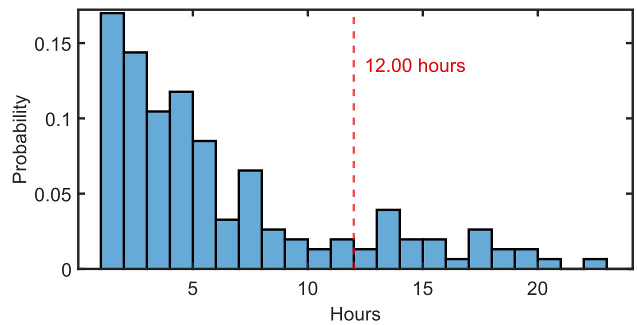

FIGURE 4. **Distribution of the duration of the accumulated hours under 35 % RES for the year 2023.**

can be freely chosen and depends on what the HESS is intended to be used for. When these periods are summed up until RES reaches a higher share in the grid again, the durations of the dark doldrums are obtained. For a more economic system design, a combination with the Pareto principle [53] is used, where 80 % of the durations can be covered using an HESS.

Classification: Due to RES such as biogas or hydroelectric power, the German electricity mix in 2023 contained at least 16.6 % of renewable energy [25]. If the dark doldrums are now defined as a scenario where only 35 % or less of the electricity mix comes from RES, then this condition can be identified for 2023. When times are summed up until the 35 % threshold is exceeded again, time spans (Dark Doldrums) emerge as shown in Figure 3. Applying a distribution function to these drops, as seen in Figure 4, it becomes evident that with approximately $\mathbf{t}_{av} = \mathbf{12}$ **hours** of system availability time, the majority (80 % Pareto) of the periods with low RES, can be covered.

If this calculation method is applied to the years 2019 to 2023, it results in a duration of 15 hours, which could cover 80 % of the periods of low wind and solar power production. Compared to this Öberg et al. [33] describe a duration time of 20 hours in their publication.

D. PARAMETER: POWER OF THE EL

The size of the EL can be specified by the power input P_{el}. This depends on the available time and the required

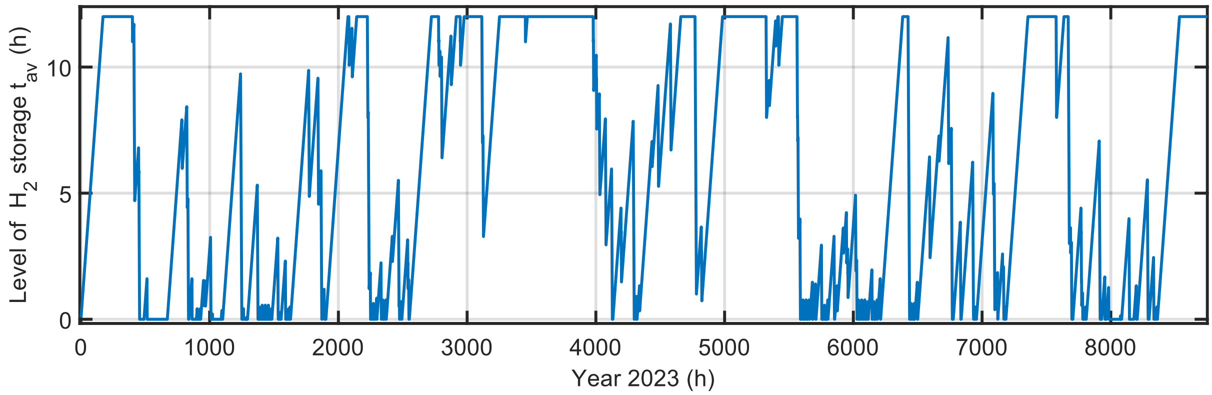

FIGURE 5. Gas storage level over the year 2023. Unloading at a RES share of less than 35 % with a relations factor of 5.

energy. It indicates the possible amount of hydrogen that can be produced and is therefore an important parameter in the overall system.

Method: In a first step, an energy balance must be done. For calculating the energy of the hydrogen storage, the efficiencies must be taken into account. In this context, the efficiency needs to be differentiated between producers and consumers. Equation (5) shows the energy balance.

$$E_{H2} = \frac{P_{gt} \cdot t_{gt}}{\eta_{gt}} = P_{el} \cdot t_{el} \cdot \eta_{el} \tag{5}$$

To determine the EL power, the formula is rearranged to (6).

$$P_{el} = \frac{P_{gt} \cdot t_{gt}}{t_{el} \cdot \eta_{el} \cdot \eta_{gt}} \tag{6}$$

For comparability and understanding, it is therefore advisable to introduce a relation factor R between GT power and EL power with (7).

$$R = \frac{P_{gt}}{P_{el}} = \frac{t_{el} \cdot \eta_{el} \cdot \eta_{gt}}{t_{gt}} \tag{7}$$

The Grid integrated HESS participates in the energy market and can therefore be controlled by different parameters. To achieve the goal of a high share of RES, the limit of RES is used to control the EL and the GT. Thus, the annual hours are divided into the runtime of the turbine and the runtime of the EL.

Classification: If there is a gas network connection on site where hydrogen can be fed in and drawn from, the EL capacity can be freely chosen. However, if there is a limitation due to storage, the relation factor R is between 2 and 10, depending on how often and how quickly the EL needs to be ready for use. Relation factors outside this range result in the storage being either mostly full or empty (a detailed analysis in Section III-E).

E. PARAMETER: DURATION TIMES THROUGH THE YEAR

The division of time throughout the year represents important factors for system design as well as economic considerations. t_{el} is the time during which the EL operates. t_{gt} is the time during which the gas turbine operates and feeds electricity into the grid. Limiting the amount of energy to be stored adds additional times: periods when the storage is empty, but the turbine could be running ($t_{standstill,gt}$), and periods when the storage is full but the EL could be operating ($t_{standstill,el}$).

Method: By combining Section III-C and Section III-D, and calculating energy quantities using historical data, the storage fill level can be determined based on the relation factor R. The threshold approach, as described in Section III-C, is used for decision-making.

Classification: For Germany in the year 2023, with a relation factor of R = 5 and a threshold of 35 %, Figure 5 is derived. From this, the following times can be determined: t_{el} = 5141 h, t_{gt} = 303 h, $t_{standstill,el}$ = 2347 h, and $t_{standstill,gt}$ = 969 h. These times also correlate with electricity market prices, as prices tend to rise when renewable energy source are less available in the grid. The various parameters describe an optimization problem that is briefly mentioned in this work to avoid exceeding the scope, but could be explored further in future research. This method was also applied to other historical data, with similar results when the threshold and R were adjusted accordingly.

F. PARAMETER: MAXIMUM FULL CYCLES PER YEAR

An estimation of the full load cycles per year is necessary to optimize the energy consumption of hydrogen compression. Additionally, this estimation can be helpful for categorizing the system.

Method: As a first approximation to estimate the maximum cycles, the previously determined t_{av} is used. Based on the overall system efficiency of the HESS η_{tot}, a cycle time t_{cyc} can be calculated using (8).

$$t_{cyc} = t_{av} + \frac{t_{av}}{\eta_{tot}} \tag{8}$$

By dividing the hours of a year by t_{cyc}, one obtains C_{max}, the maximum cycles per year, assuming that the EL power is equal to the turbine power. If the EL power is smaller, fewer cycles can accordingly be operated. If it is larger, more cycles can be operated per year.

Classification: To achieve the maximum system efficiency $\eta_{tot,max}$, combined cycle gas turbine (CCGT) (61 % [54] and solid oxide EL cell (SOEC) (84 % [55]) must be combined. This allows the system to theoretically reach an efficiency of $\eta_{tot,max} = 0.51$. When the values $t_{av} = 12$ hours and $\eta_{tot} = 0.51$ are substituted into the equation, a cycle time of 35.53 hours is obtained. This means that a **maximum of 246.5 cycles per year** (8,760 hours) can be operated. A more probable efficiency results from combining an open cycle gas turbine (OCGT) with a PEM or Alkaline electrolysis (AEL), at approximately $\eta_{tot} = 0.28$ and thus with just under 160 cycles per year.

G. PARAMETER: STORAGE PRESSURE

The storage system is located between the EL and GT, being fed from the EL through a compressor. The compressor raises the pressure to a desired storage level.

Current projects storing large quantities ($\geq$ 6 t = 200 MWh) of hydrogen operate at relatively low pressures, for example, 60 bar [56]. This can be justified by the fact that after the 30 bar EL [57], only one compression stage is necessary, thus minimizing energy consumption at high annual operating hours. Additionally, the project "HyExperts Hydrogen Model Region Chemnitz" [28] demonstrated that large cylindrical pressure vessels are the most cost-effective storage method when salt caverns are not available (Table: 1). Therefore, this work focuses on large cylindrical pressure vessels (20 - 150 bar). However, a primary factor could also be space requirements, mobility, or another influencing factor, which might lead to an alternative storage solution.

Method: For a pressure optimization that reflects both energy costs and storage costs, calculations can be simplified by scaling them to 1 MWh and a granularity of 0.1 cubic meter per pressure vessel.

By increasing the pressure, more energy can be stored per cubic meter of the vessel. This results in a decreasing curve with increasing pressure, where the optimum is at the maximum pressure (Figure 6 red curve). Beyond a certain pressure level, one tank can be saved to store one megawatt-hour, resulting in a step function.

However, energy costs for compression increase with rising pressure (Figure 6 blue curve). To estimate the maximum power consumption, the maximum full cycles from Section III-F are used. This means that the ideal pressure of the real system is at or above the optimized pressure, but not below it.

Equation (9) is used for the approximation of the work demand for hydrogen compressing to a certain pressure level [58]. Equation (9) was adjusted by Boyle's law with $p_1 \cdot V_1 = p_2 \cdot V_2$, additionally, the efficiency η_{comp} of the compressor is included [59]. With the efficiency, a real system is approximated. Finally, the annual cycles $C_{an,max}$ and the years Y were integrated into the equation as multipliers. The compression factor Z varies for different pressures. $\mathcal{R}$ is the universal gas constant. T the absolute temperature and n represents the number of moles.

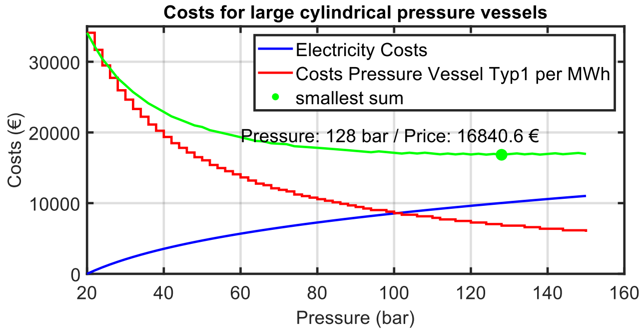

FIGURE 6. **Pressure optimization for 20 years and costs of 2200 €/m^3 for 150 bar large cyl. pressure tanks for storing 1 MWh$_{LHV}$ of H_2. With a maximum electricity price of 112 €/MWh (av. Price of 72 €/MWh for 2023), with 5810 hours runtime. Blue indicates the increasing compression costs. Red: decreasing CAPEX costs. Green: Sum of the curves, green point marks the minimum sum of the curves.**

$$W_{comp} = C_{an} \cdot Y \cdot Z \cdot n \cdot \mathcal{R} \cdot T \cdot \ln\left(\frac{p_2}{p_1}\right) \cdot \frac{1}{\eta_{comp}} \tag{9}$$

Both decreasing and increasing costs are calculated for each bar of pressure and graphically compared. The lowest sum thus results in the lowest costs.

Classification: The efficiency η_{comp} for hydrogen compression can reach different values depending on the specific use case and application. In their comprehensive study, G. Sdanghi et al. [60] highlight various approaches, techniques and applications. For the here presented, HESS a three-stage linear compressor system for hydrogen applications could be used. One of the referenced compressors can increase pressure levels from 20 up to 950 bars, with an efficiency of 73 % ($\eta_{comp} = 0.73$).

For the calculation, a period of 20 years is also assumed, as it is expected that the plant will be depreciated by then. A maximum electricity price from 2023 of 112 €/MWh is used for the calculated electricity price, as this achieves the maximum annual runtime of the EL at 5800 hours per year, resulting in an average electricity price of 72 €/MWh. This corresponds to the maximum 246.5 cycles from Section III-F. A minimum pressure of $p_1 = 20$ bar is assumed, as large gas turbines require a certain pressure. The calculation shows an optimum at 128 bar. The green curve in Figure 6 shows that the cost optimum does not change significantly beyond approximately 80 bar. It is therefore conceivable that large cylindrical storage vessels can be operated at maximum pressure, allowing them to store larger quantities of hydrogen.

H. PARAMETER: DYNAMIC OF EL

The dynamic response of the EL is an important factor for participating in grid services. The grid operator sets a minimum time response that must be met in order to participate in the ancillary services. The gradient $\frac{\Delta P}{\Delta t}$ describes the possible

TABLE 3. **Different power control mechanisms [14].**

Power Control	min. Size [MW]	Availa. [sec.]	Symmetry	Dur. [h]	Gradient [kW/s]
FCR/PCR	1	30	sym.	4	33.34
aFRR	1	300	asym.	4	3.34
mFRR	1	750	asym.	4	1.34

rate of change of the EL and must be fast enough to comply with the grid code.

Method: The change in power, $\frac{\Delta P}{\Delta t}$, can be determined using the specifications provided in the data sheet. For this, the electrical power P_{el} of the EL, the lower limit of the operating window u, and the dynamics of the EL Δ_{el} are required. Additionally, it is necessary to know the trade sizes (P_{ts}) in which power is traded in the ancillary service market and the amount of balancing power P_{anc} to be offered. This results in (10), which determines the power change gradient of the EL. This gradient must be greater than the required gradient set by the TSO.

$$\frac{\Delta P}{\Delta t} = \frac{P_{el} \cdot (1-u) \cdot \Delta_{el}}{\frac{P_{anc}}{P_{ts}}} \tag{10}$$

Often, data sheets only specify the operating window and the ramp-up time t_{ru}. Using (11), Δ_{el} can be calculated from this information.

$$\Delta_{el} = \frac{(1-u)}{t_{ru}} \tag{11}$$

Classification: The European TSOs issue the required amounts of reserve power in the ancillary service market [14]. Participation in this ancillary service market is possible if the necessary conditions are met. The aFRR is allocated to bidders one day in advance. Balancing longer or higher power deviations is done through the mFRR in a manner analogous to the aFRR. To participate in the Frequency Containment Reserve/Primary Control Reserve (FCR/PCR), a minimum of $P_{ts} = 1$ MW of symmetrical power must be available within 30 seconds and capable of being regulated with a gradient of 33.34 kW/s. Table 3 summarizes the requirements for the various ancillary services.

As an example, the MCLyzer3200 from McPhy can be used, for which all necessary data are available [61].

- $P_{el} = 16$ MW
- $\Delta_{el} = \geq 5\,\% = 0.05$
- $u = 10\,\% = 0.1$

For this EL, P_{anc} can be selected up to a maximum of 14 MW of offered balancing power, as otherwise the minimum load requirement would not be met. This results in a $\frac{\Delta P}{\Delta t}$ of 51.42 kW/s. Here, an AEL is deliberately used because PEM systems can achieve higher gradients (103 kW/s) [62]. Anion exchange membrane (AEM) and SOEC technologies still need to demonstrate the dynamics they can achieve in the power range of several megawatts.

Based on (10), it can be seen that even if a certain gradient cannot be achieved, the offered power P_{anc} can be reduced to reach the required gradient. For example, if only 7 MW is offered instead of 14 MW, the system can achieve a gradient of 102 kW/s, which is twice the initial gradient. As long as the gradient of the EL exceeds that of the FCR/PCR, it can be utilized for this purpose [63].

I. PARAMETER: MINIMUM SIZE OF THE EL

In principle, the power of the EL can be chosen like in section III-D. A minimum size $P_{min.}$ for a grid-friendly application must be described for participation in the ancillary service market.

Method: The method for determining the minimum power of the EL can be described using the defined rules of the grid operators and the manufacturer's specification for the lowest power, as described in (12). It must be determined in what trading unit P_{ts} the control power is traded and whether it is asynchronous or synchronous. P_{ts} represents the requested package size of the tradable control power. The symmetry parameter s is introduced here and can only take on the values 1 (asymmetric) or 2 (symmetric). If symmetric control power is offered, the EL must be operated in partial load mode to be able to reduce the load to a minimum as well as to draw more energy from the grid.

$$P_{min.\ el.} = s \cdot P_{ts} \cdot (1+u) \tag{12}$$

Classification: To participate in the European FCR/PCR ancillary service market, there must be a minimum size of $s \cdot P_{ts} = 2$ MW available above the minimum capacity of the EL, allowing for a symmetrical minimum offer of 1 MW (Table 3). As an example, the data of the McLyzer800 ($P_{min.\ el.} = 2.4$ MW for McPhy [61]) can be used, which is offered with a power of 4 MW and specified with a minimum load u of 20 %. According to (12), this model could thus offer 1 MW of synchronous FCR/PCR by operating at 3 MW during the offered period, allowing for 1 MW to be regulated up and down while remaining above the specified minimum load. ELs have already been successfully used for the second-fastest form of regulation, FCR/PCR, as seen in the Energiepark-Mainz [63]. Furthermore, it has been demonstrated that participating in the ancillary service market can lead to significant cost savings for hydrogen production (Discussion in section V-A).

IV. HHyLDA-TOOL

To determine the optimal parameters, the proposed methodology has been implemented in a MATLAB® application.

The software tool can, therefore, determine the design of the subsystems directly based on the previously described methods and provide information about the overall hybrid battery and hydrogen energy storage system. The software tool can also make statements about space requirements, sizes, and construction based on the equations. To achieve this, databases of commercially available systems are integrated into the software.

In Figure 7, the different options are marked with numbers and letters. With (7), it can be shown from what availability

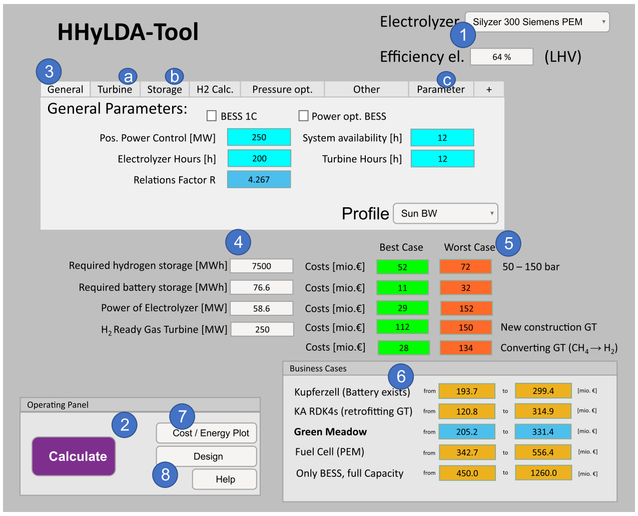

FIGURE 7. **Interface of HHyLDA-Tool. (1) Electrolyzer Database, (2) Calculates all values, (3)(a–c) Fig. 8, 9: Parameter definition, (4) and (5) Calculated values, (6) Business Cases, (7) Creates Fig. 13, (8) Creates Figs. 10, 11, 12.**

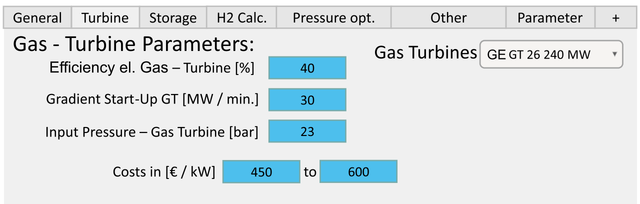

FIGURE 8. **Turbine parameters in HHyLDA-Tool. With dropdown for Gas turbine database and different parameters.**

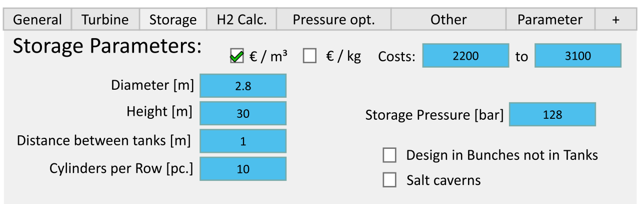

FIGURE 9. **Storage parameters in HHyLDA-Tool. Dimensions of the pressure vessels. Different storage possibilities.**

time onwards the system becomes cheaper in terms of CAPEX as a HESS compared to a pure BESS (Figure 13). (8) estimates the land requirements for BESS, EL, and H_2 storage (Figure 10,11,12).

V. RESULTS AND DISCUSSION

With the proposed methodology implemented in the HHyLDA-Tool, the cost estimation of the entire system is possible. The individual business cases can be compared directly. Additionally, a function is implemented, (7) in Figure 7, to vary the availability time and generate a graph accordingly. Figure 13 illustrates the behavior of CAPEX for HESS as the stored energy amount increases, place side

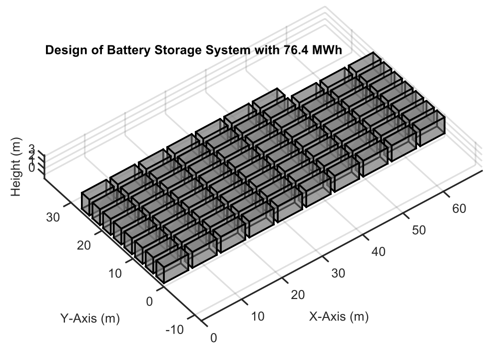

FIGURE 10. **Design of a BESS with P = 250 MW and 76.4 MWh.**

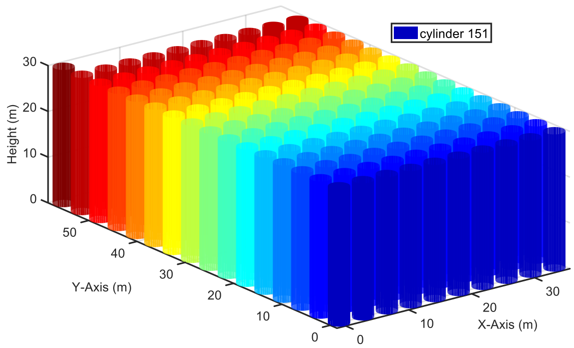

FIGURE 11. **Design of H_2 pressure vessels (128 bar, 2.8 m Diameter, 30 m Height, P = 250 MW and 12 hours availability time.**

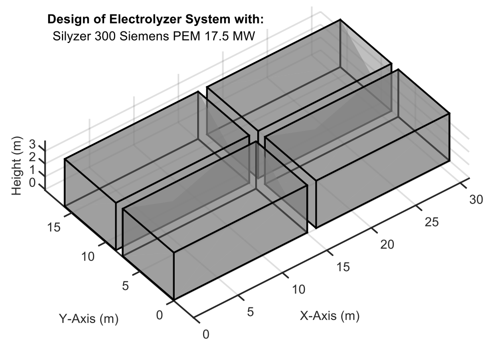

FIGURE 12. **Design of the footprint of 58.6 MW EL Power. Siemens energy specifies the Silyzer 300 with a 15.0 x 7.5 x 3.5 m footprint and P = 17.5 MW [62].**

by side with CAPEX for pure BESS. This can be easily conducted for different capacities.

The time of the four intersections increases slightly when the power of the system is increased. However, up to a power plant capacity of 2 GW, the statement remains roughly the same as in Figure 13. The HESS becomes cheaper in terms of CAPEX somewhere between an availability of 1.3 and 7.3 hours (more likely in the range of 2-4 hours), depending on which of the four points in Figure 13 is considered. Such power plants are likely subject to economies of scale, and

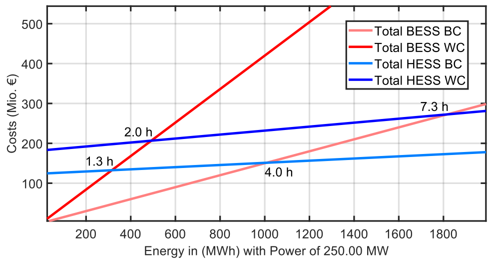

FIGURE 13. Comparison of the costs for business cases between greenfield and pure BESS over the stored energy amount.

therefore, the worst case cost variation of the HESS may not be probable.

A. OFFERING PARTIAL LOAD OF ELECTROLYZERS FOR ANCILLARY SERVICES

Equation (10) shows that P_{anc} appears in the numerator, and thus can influence the gradient. More specifically, this means that even an electrolyzer with a small rate of change, for example 1 %, can offer part of its load as balancing power and can adjust this smaller amount quickly enough to comply with grid regulations. For instance, this means that a 100 MW electrolyzer can provide 10 MW of both positive and negative balancing power, and thus operates at 90 MW of normal power. This allows it to regulate up by 10 MW and down by 10 MW. When the values (u = 0.25, P_{ts} = 2 MW) are inserted into (10), the following calculation results:

$$\frac{\Delta P}{\Delta t} = \frac{100MW \cdot (1-0.25) \cdot 0.01\frac{1}{s}}{\frac{10MW}{2MW}} = 0.15\frac{MW}{s} = 150\frac{kW}{s}$$

This means that the SOEC could potentially also be used to provide grid services. It is also conceivable that, due to the smaller part-load range, the electrolyzer may experience less degradation and could have a slightly higher efficiency.

B. PARAMETER VARIATION - RELATIONS FACTOR R

When the value of the factor R (7), the ratio between GT and EL, is fixed, it can be observed that despite higher costs per kW (Tab.: 2) of the different EL technologies, the overall system costs differ only slightly. When different R factors are chosen, as shown in Table 4, it is apparent that with a higher R, EL accounts for an increasingly smaller proportion of the total system costs. When these costs are compared, it can be seen that AEL or PEM ultimately differ by a maximum of 16 %, but typically in the range of 1-5 %. Therefore, it is preferable to use the system with higher efficiency. On the other hand, SOEC can lead to a cost increase of 1.26 to 2.04 with a factor of 2. However, if R is at 10, additional costs of only 7 to 30 % are expected. It should be noted, however, that SOEC is considered less dynamic.

C. EFFICIENCY ANALYSIS RELATED TO CAPEX

When the various subsystems of EL and turbine technology are varied and the resulting price is related to the overall efficiencies, one obtains the price in million euros per efficiency point in percent, as can be seen in Table 5. It should be noted that the efficiencies of EL technologies vary significantly between manufacturers. Both PEM and AEL technologies have varying degrees of efficiency. However, SOEC typically offers a higher efficiency compared to AEL and PEM. All efficiency values are based on the Lower Heating Value (LHV). The two main conclusions that can be drawn from Table 5 are that systems which are intended to have the highest possible annual utilization should have relatively low costs per efficiency point and therefore exhibit high overall efficiency. However, if such a system is used only as a backup system with few cycles per year, as per the federal government's power plant strategy, then the most cost-effective system based on CAPEX may be preferable, even if it means accepting lower efficiency.

TABLE 4. Variation of the factor R for different EL technologies. P = 250 MW, t_{av} = 12 h. All values are based on Table 1 and 2.

R	2	2	5	5	10	10
Case	**Best**	**Worst**	**BC**	**WC**	**BC**	**WC**
	mio. €	mio. €	mio. €	mio. €	mio. €	mio. €
AEL	225	358	195	297	186	276
PEM	238	416	201	320	188	288
SOEC	300	851	226	493	201	374
Additional costs factor between AEL and PEM						
Factor	1.0578	1.1620	1.0308	1.0774	1.0108	1.0435
Additional costs factor between PEM and SOEC						
Factor	1.2605	2.0457	1.1244	1.5406	1.0691	1.2986

TABLE 5. Representation of the costs per efficiency point of the overall system with variation of the EL and gas turbine subsystems. P = 250 MW, t_{av} = 12 h. η_{el} in LHV.

EL	GT	EL	GT	Total	BC	WC	BC	WC
		%	%	%	M€	M€	M€/%	M€/%
AEL1	OC	60	41	24.6	196	297	8.0	12.1
AEL2	OC	64	41	26.2	195	294	7.4	11.2
PEM	OC	64	41	26.2	201	321	7.7	12.2
SOEC	OC	84	41	34.4	215	455	6.2	13.2
AEL1	CC	60	61	36.6	284	355	7.8	9.7
PEM	CC	64	61	39.0	287	371	7.4	9.5
SOEC	CC	84	61	51.2	297	462	5.8	9.0

AEL1[64], AEL2[65], PEM[66], SOEC[55], OC[67], CC[54]

D. SYSTEM DESIGN-EXAMPLE RDK4s KARLSRUHE

At this point, an optimized system approach should be described, for demonstration purposes only. Any other location can be used for this as well. Since it has been shown based on the footprint that large areas are required to implement such a system, an existing power plant site should always be preferred as the location. This has many advantages, such as utilizing existing infrastructure, acceptance in the population, or sufficient land availability. Power plants that are already connected to a district heating or steam network are particularly suitable, as EL also generates heat for many hours a year. In regions with abundant solar power, heat could be stored in large-scale storage for winter use. Additionally, existing steam power plants should be utilized, because they have a higher efficiency compared to regular GT. Karlsruhe meets all of these criteria and simultaneously offers the largest CCGT in Southern Germany with 363 MW of power, making it predestined as a location for retrofitting to hydrogen. Additionally, MiRO (Mineraloelraffinerie Oberrhein GmbH & Co. KG [68]) and the Daimler truck plant, with the hydrogen truck (in Wörth am Rhein [69]), are nearby, where hydrogen demands are already present or will probably emerge. In Daxlanden, one of the largest grid nodes is located, where the HESS can participate in the highest voltage grid. Possibly, additional energy in the form of hydrogen or its derivatives could be delivered via the Rhine through inland shipping and used within the system to cover dark doldrums.

A future connection to the Hydrogen Backbone would be desirable [29]. Currently, the GT can still be operated with natural gas, allowing blending and backup through a natural gas connection. Injecting hydrogen into the natural gas network is also permissible up to 10 % content if no hydrogen network is available yet [52]. Finally, when all parameters are entered into HHyLDA-Tool, a 363 MW GT yields a 163 MW AEL (Sunfire AEL [65]). A 134 MWh BESS with a 7.5 GWh_{LHV} (225 t) H_2 storage results in 12 hours of availability time (t_{el} = 200 h, t_{gt} = 12 h, R = 6.2). A complete system with retrofitting the CCGT would cost between 183.1 million € and 487.7 million € . This significant price range for retrofitting arises from the varying estimates of different studies. However, if only blending (25 % H_2) is initially applied, the system costs are more likely to be in the range of 100 million € or below [36]. Based on this, it can be shown that existing CCGT should initially be converted. The addition of the HESS offers many advantages (power control, grid stability, peak shaving and booster function), such as high flexibility and various methods for revenue generation. The same HESS as a greenfield site would cost between 428.1 and 527.6 million €.

VI. CONCLUSION

In the course of this study, it is demonstrated how subsystems in a HESS should be sensibly designed so that they are energetically coordinated. If the HESS is composed of EL, H_2 Storage, BESS, and GT, many advantages can be achieved. For one, the BESS can be chosen to be smaller, and the decoupling between energy storage and resource consumption can be ensured. It is shown that starting from just a few hours (2–4 hours) of availability time, the HESS becomes significantly more cost-effective than a pure BESS, in terms of CAPEX of the sub systems. Such a HESS is capable of black starting, can participate in the balancing energy market, and in the energy-only market. The greatest advantage, however, lies in the cost-effective scaling to large amounts of energy, in combination with the fast response time. It is demonstrated that grid-friendly EL must have a minimum size and that the hydrogen storage should be of a sensible scale. Also, the ratio between EL and GT should not be freely chosen in the absence of a pipeline connection, as this would otherwise lead to extreme downtime for either GT or EL. Salt caverns, if available, should be preferred as they are more cost-effective and can store large amounts of energy. However, if these are not available, large cylindrical vessels should be chosen for maximum pressure. Bundle cylinders and other storage concepts are more expensive for the energy amounts to be stored and are primarily recommended when other factors, such as space requirements, predominate. All in all, depending on the use case, a different HESS concept is advisable. If the system is to be operated continuously, a high overall efficiency should be aimed for. If the system serves as a backup or booster, with few cycles per year, low CAPEX should be preferred.

The authors are aware that more in-depth system designs are necessary to describe such systems. For example, the increase in capacity required in the BESS due to higher losses from higher C-rates is simply accounted for by an additional margin. In-depth physical models are necessary to bridge this gap. The HHyLDA-Tool is only intended to provide initial insights into costs, conceptualization, and subsystem sizing, as well as the footprint, based on simple formulas and estimations.

In the HHyLDA-Tool, various parameters can be adjusted, as shown in Fig.7 (c). This includes the levelized costs for individual parts. For example, lower battery prices can be incorporated, or regional differences can be factored into the calculations. Due to the declining cost of batteries, the "beyond 4-hours" discussion [70] has already shifted towards 8 or even 12 hours, during which pure BESS represent the more cost-effective storage method, when operational expenditures (OPEX) is included. The media already writes about battery prices around or below 100 €/ kWh [71], [72], [73]. This raises the question of whether HESS, as presented in this study, will find any application at all, given the issue of round-trip efficiency. On the other hand, there are currently few answers on how to cover long-lasting dark doldrums with 100 % RES.

VII. OUTLOOK

The HHyLDA-Tool provides an initial interpretation based on the methods presented and the defined parameters. Based on the system design, future studies can build models from this point onward that simulate the individual subsystems, their dynamics and their interactions. As part of this work, a CAPEX analysis is performed, which summarizes the individual system costs of the subsystems. The actual project costs for a HESS are higher because expenses such as land acquisition, project planning, or buildings are not included. This aspect can also be addressed in a follow-up study. Further in-depth investigations can include a comprehensive cost analysis. This could examine revenues and expenditures related to the energy market, ancillary services, black start capability, or OPEX. Additionally, the overall utilization of waste heat should be included in the calculations, as this can be over 60 % in systems with low efficiency. These studies could ultimately be consolidated into a comprehensive final analysis.

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