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«Optimising Investments and Strategic Operation of Hybrid Energy Hubs Under Uncertainty»

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From me – to myself:
"*. . . Congratulations, worked so hard forgot how to vacation . . .*" (*Austin Richard Post, 2017*).

Until next time,

Dimitrios Eleftheriou
Copenhagen, Denmark
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Abstract

As the world undergoes a profound energy crisis which is reshaping the latest known motivation but also interests of potential investors in energy projects, green transition is once again being challenged. The soar of electricity prices since the post COVID-19 recovery period not only derailed the status quo of future energy market outlooks, but also widened the gap between RES generators and PtX facilities' collaboration due to conflicts of interest under private economic perspectives. The relative new concept of green energy hubs is bibliographically able to provide an agile symbiosis network, where collaborative behaviour along flexibility can lead to optimised overall returns. Such investor interactions under an energy hub setup are being set under question in the present analysis, researching what the uncertain future has to look like in order to achieve flourishing coexistence of actors without show stopping conflicts of interest. A 20-year analysis of an energy hub is being set under the microscope through 4 representative years under full hourly resolution (8760 hours). An investment model is being developed under the uncertainty of day ahead electricity price scenarios in DK_1 bidding zone, which defines the necessary pricing levels of PtX fuels deeming them worthy of inspective elaboration in such a context. The competitive nature of co-existing PtX products in such an environment is also being examined. An optimised long term hourly dispatch under uncertainty is produced and analysed, providing insights for the required internal pricing that long term contracts would have to revolve around in order to satisfy all investor specific requirements. Green e-fuel prices of 0.79 $€_{21}$/MWh MeOH as well as 0.73 $€_{21}$/MWh NH_3 prove to be sufficient on balancing the opportunity costs but also risks that RES generators face by committing to long term EH contracts, while still allowing considerable profitability margins for the EH coalition.

Keywords
Energy hub, Green fuels, Electricity markets, Co-optimisation of investments, Bilateral contracts, Feasibility analysis, Decision making under uncertainty.

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Nomenclature

List of Acronyms and Abbreviations

Acronym / Abbreviation	Definition	Acronym / Abbreviation	Definition
CAPEX	Capital Expenditures	H_2O	Water
CF	Capacity Factor	IRR	Internal Rate of Return
CHP	Combined Heat and Power	LCOE	Levelised Cost of Electricity
CHS	Compressed Hydrogen Storage	Lt	Lifetime
CO_2	Carbon Dioxide	MeOH	Methanol
COD	Commercial Operation Date	NH_3	Ammonia
CRF	Capital Recovery Factor	NPV	Net Present Value
DA	Day Ahead	OPEX	Operational Expenditures
DCF	Discounted Cash Flow	PPA	Power Purchase Agreement
EBT	Earnings Before Taxes	PtX	Power to X
EBIT	Earnings Before Interest and Taxes	PV	Photovoltaics
EBITDA	Earnings Before Interest, Taxes, Depreciation and Amortisation	RES	Renewable Energy Systems
EC	Electrolyser	TAEC	Total Annual Economic Cost
EH	Energy Hub	UC	Unit Commitment
FLH	Full Load Hours	vO&M	Variable Operational & Maintenance Costs
fO&M	Fixed Operational & Maintenance Costs	VRE	Variable Renewable Energy
FV	Future Value	WACC	Weighted Average Cost of Capital
H_2	Hydrogen	WT	Wind Turbine

1. Introduction

As of 2022, with the up to date global primary energy consumption soaring to more than 2-folds in comparison to the 1980's recorded levels [Ref 1], running in parallel to constantly evolving efforts aiming to ensure sustainable and secure provision of energy to all, such as the UN's Sustainable Development Goals [Ref 2], the importance of energy as well as challenge magnitude that mankind faces in the current century is being stressed. Section 1 aims to present an overview of the major concepts revolving around the undertaken analysis, while also explore and discuss the state-of-the-art literature and research development around the field of Energy Hubs.

1.1. Energy Hub(s) Concept

The first well documented and elaborated mention on the as today known Energy Hub (EH) idea dates back to 2005 by the Power Systems and High Voltage Laboratory at ETH Zurich, within the boundaries of the project "A Vision of Future Energy Networks (VOFEN)" [Ref 3]. There, a depiction of a future energy system 20-30 years ahead has been presented, pointing out the tendency towards the formation of Multi-Energy Systems (MES), taking advantage of the synergetic abilities of co-existing energy carriers in an attempt to complement, or better shape, a new energy reality.

A formal and descriptive definition of an EH has been given by Geidl & Andersson in the same year as: *"EH is a unit that provides the functions of input, output, conversion and storage of multiple energy carriers"* [Ref 4]. Consequently, the interaction between various carriers could broaden the EH concept to the overall framework of "Hybrid Energy Hub(s)". The deployment of such kind of systems, reflects directly on the aforementioned SGGs, as such structures, aiming to meet more than one demand, can enjoy higher overall efficiencies, lower emissions and a directly reduction of the demand and corresponding costs of primary energy.

Mohammadi et al [Ref 5], have thoroughly examined the most important work carried out on the EH field across the years, pointing out the most frequently used resources as well as technologies. The most commonly encountered input sources are no others than natural gas and grid electricity, to respectively produce electricity and heat outputs, as seen in **Figure 1**. Of course, natural gas and part of the grid's energy is not a renewable source of energy. Nevertheless, under the global expansion of the usual renewable electricity producers (WT & PV) along with the constantly growing international Net-Zero pledges, a direct link with the overall EH concept is getting shaped.

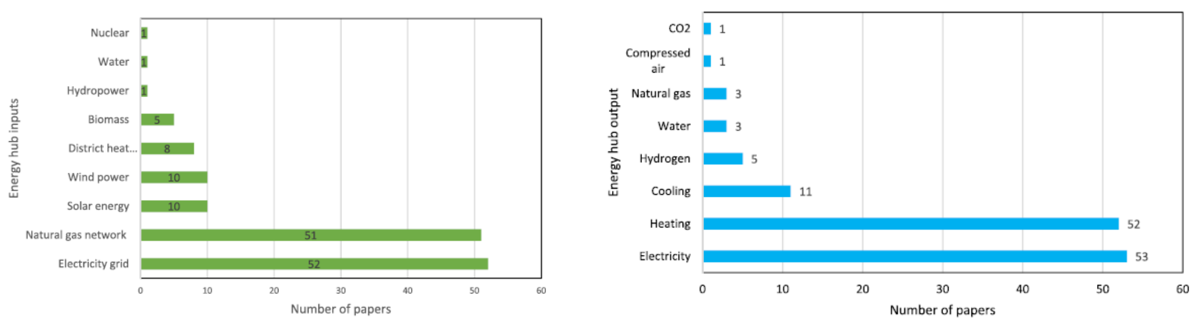


Figure 1. Usual inputs and outputs for energy hub models in the literature [Ref 5]

Especially in parts of the world, such as Denmark, where already in 2022 such technologies account for more than half of the already by ¾ renewable electricity mix [Ref 6], the scenery seems promising for such synergies. Bearing in mind that when zooming out to observe the Danish energy system as a whole and its breakdown of primary energy use mix, then the share of renewables drops dramatically to more than half (~34.5%) [Ref 6]. Decarbonizing the hard-to-abate sectors, such as industry and transport, imposes a major challenge worldwide. In other words, the simple expansion of the renewable electricity capacity won't solve the puzzle. The feasibility and cost efficiency of solely storing electricity proves to be doubtful at scale, thus more refined and combined solutions have to emerge. Interconnections between countries, e.g. the Nordic areas, could assist the situation via alternative storage means like pumped-hydro, but will still not solve the issue. The road to a secure and flexible Net-Zero is a one way street and entails the wholistic integration of various energy carriers. Such solutions have been examined and proven to be feasible on a European level by even using already existing technologies [Ref 8]. This flags the importance of pioneering projects such as Energy Hubs.

1.2. Optimisation of Energy Hubs

Even though the concept of EH has been publicly discussed for more than 20 years now, gaps and under development areas are being frequently found. Maroufmashat, A., et al has in 2019 undertaken an extensive research through more than 200 published papers on modeling and optimisation of EHs, concluding that a clear knowledge gap is evident [Ref 9]. On the whole the so far scientific research focuses on 3 main areas: planning & operation, economic & environmental impacts and applications of EHs.

Examining such aspects on the whole can lead to increased security of supply, while also to reduced O&M costs, fuel consumption as well as system emissions. However, the performance of an EH is far from fitting in a mould. A plethora of variables affect an operation that would prove optimal, and subsequently the overall capacity selection and investment. Commodity price correlations, technological maturity, demand load, production forecasts and also policy are namely some [Ref 10].

Optimisation of such applications are nowadays synonymous to mathematical modelling across the scientific community. Decision making under uncertainty is a widely researched field undergoing constant development up to date. Stochastic models aim to introduce multiple scenarios in an attempt to optimise in parallel to the potential uncertainties. A more thorough descriptive analysis will be presented on the case specific model, analysed in Section 2.

1.3. Investment Evaluation in Energy Hubs

Accounting for the uncertain costs of the EH's inputs while pricing its outputs is a primary concern across potential investors. Adding on top the overarching opportunity costs from committing to such a setting via potential bilateral agreements such as PPAs that investors may have to agree upon, creates a multi-layer optimisation issue that needs more sophisticated approaches and account for the perceived and acceptable investors' risks.

Consortiums are being frequently formed in EH settings, with interests of various directions. For such reasons, reaching a desirable agreement is a multi-variant objective. Energy models aim to account for the aforementioned elements, and even more, to define the best possible setup, while accounting for the possibility of changes in future energy prices. An overview of 36 optimisation studies across the years, which include economic considerations, was also presented by Maroufmashat, A., et al in 2019 [Ref 9]. Most of them, have been focusing on CHP settings aiming to produce electricity and heat while utilising natural gas and grid electricity, with less than half including RES or storing systems and less than a third examining the production of sustainable fuels.

Monte Carlo valuation methods are the usual literature approaches of uncertainty assimilation in a range of applications via the use of probability distributions. The flexibility of reacting to volatile market prices, as an example, is being brought to the forefront with such a method by Kienzle, F., et al [Ref 11], showcasing the additional value which is being brought by the incorporation of different EH configurations and the addition of storage means. Kienzle advocates that energy prices are in their essence casual, depending on the laws of supply and demand, however even if their characteristics can be forecasted, an exact estimate of prices in a year from now relies in pure luck. However, such simulations are usually limited to being utilised in settings with few assumptions and great complexity, and are frequently accompanied by set capacity assumptions while aiming to account for the addition or inclusion or a pre-determined technological capacity.

1.4. Incentives & Opportunities

Electricity market prices consist a determinant factor over the trajectory of future capacity investment types, the possibility of synergies and the operational focus within EHs, but also upcoming incentives towards the establishment of more renewable technologies.

IEA has recently analysed the justification between the observed up to date soar of energy prices [Ref 12]. The unexpected plunge in global energy demand in the beginning of the Covid-19 crisis dropped the prices of many fuels to their lowest point in decades. But the rebound effect due to the incentives of a rapid global recovery in parallel with climate effects and inadequate supply increase has made energy prices to jump and remain in high levels for many months now. Natural gas prices sky rocketed 10-folds in comparison to their 2019 levels, with coal following with a 5-times relative increase. These in combination with higher carbon prices due to increased emissions, while adding on top the crisis in Ukraine and its global knock-on effects, resulted to a new electricity price reality and concerns over the general European security of supply.

This electricity price soar is not a reaction to a single unexpected event, but rather a combination of supply and demand factors, with no clear pathways ahead. With prices expected to return to their pre Covid-19 levels around the end of 2022 [Ref 13] before the conflicts in Ukraine, it becomes apparent that such hopes will have to get pushed significantly farther in time.

Nevertheless, a return to the global energy price “normal” will ultimately take place under a free market. And this return along with the push of investments in renewable technologies while getting closer to the 2050 milestone, will sooner or later re-ignite the pre-covid tendencies of VRE self-cannibalisation effects observed in electricity markets. A recent publication by Prol et al in 2019 researched such tendencies in the Californian wholesale electricity market (CAISO), concluding that WT and PV generators are at risk if no additional mitigation measures such as storage, demand management and interconnections will be set in place [Ref 14]. This effect, in Layman’s Terms, is observed when high penetration of RES in the energy system ends up undermining their own value and possible returns. With the reason being that when RES generators are truthfully bidding in the electricity market according to their almost zero marginal cost, they cause a declination of wholesale electricity prices due to the merit-order effect, assuming that their generation suffice for covering the hourly demands.

It becomes apparent that creating high and long-term value for self-produced renewable electricity is subject of multi-carrier collaborations in EH synergies. Coupling renewable electricity generators with PtX assets can be a win-win for all actors, where the portfolio of RES investments gets diversified and backed up by flourishing long-term feasibility analyses, while the hard to abate sectors, such as transportation and industry, get greener and closer to a

Net-Zero. For these reasons, both international and national signals have been published towards such incentives, and even more are on the pipeline.

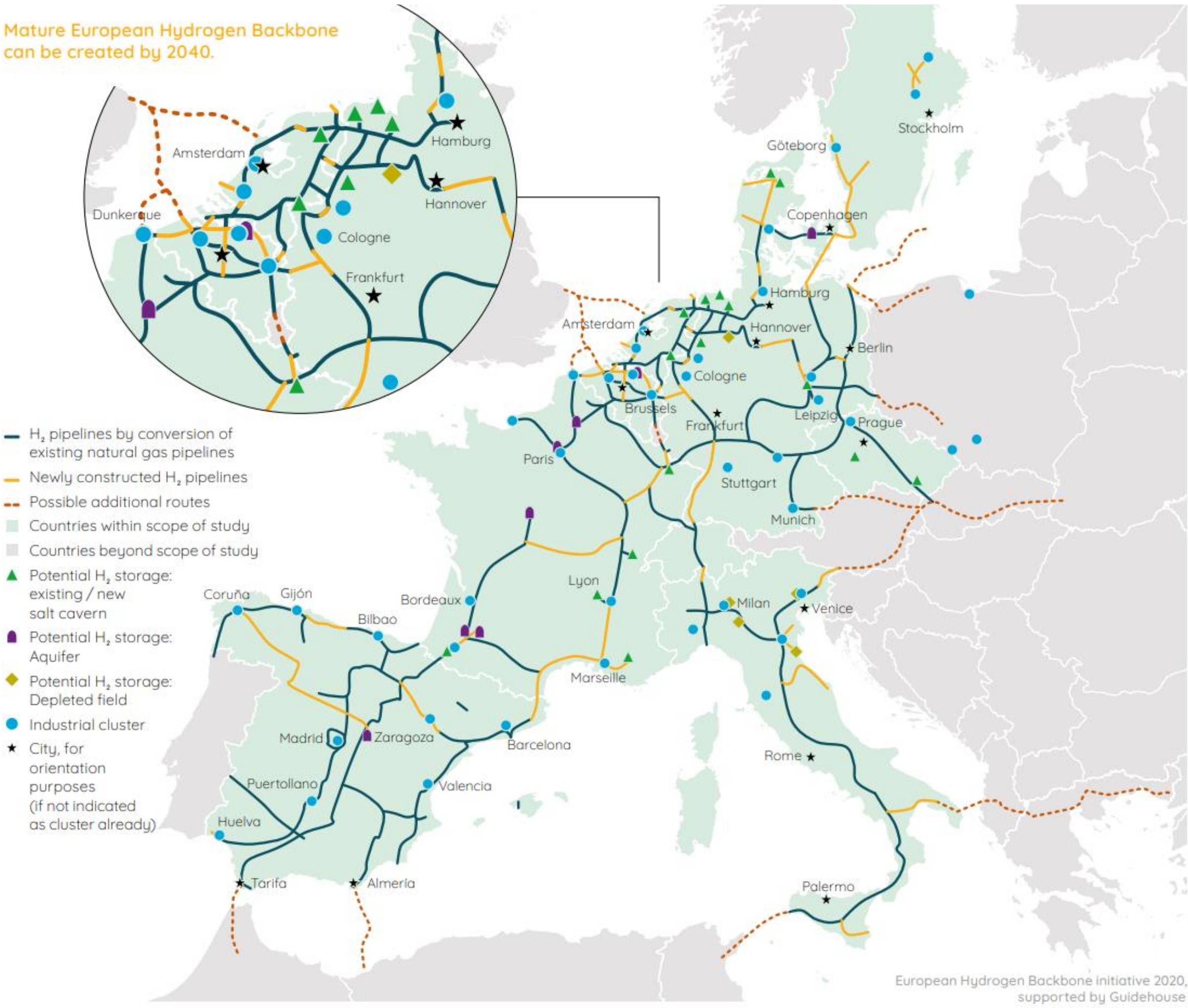


Figure 2. European Hydrogen Backbone map [Ref 15]

With the greater maturity of clean fuel generation techniques, transportation, distribution, storage and safety considerations come to the forefront. According to recent analyses, a wide-spread network of hydrogen transportation links via the re-purposing of exiting gas infrastructure and parallel strategic investments in new pipelines and compression units could achieve a well-established and cost-effective hydrogen economy deployment across a major share of Europe by 2040, as can be seen in **Figure *2***. External transportation of H_2 will also be feasible through this network. Existing gas pipelines will account for up to 60% of the network share, with the expected transportation cost of H_2 rising to figures between 0.17-0.32 €/kgH_2 per 1000km. The overall necessary investments would sum up to 80-143 billion € [Ref *15*].

Green and blue hydrogen seem to be a promising and decisive solution towards climate neutrality, with the latter having to bear additional costs of capturing and storing its CO_2 by-products to be considered carbon-neutral. Such H_2 can serve as both an energy carrier and clean fuel for the hard to abate sectors but also as an energy storing means. Thus, driving down the cost of H_2 production while improving its maturity and its de-centralised production could be a key push towards Net-Zero.

Methanol (MeOH) could also play a key role in a greener future, acting as a fuel for the internal combustion engines but also in other uses like cooking [Ref 16]. A key advantage of methanol is its CO_2 utilisation for its formation, something increasingly useful in future pathways alongside all other carbon capture plans. MeOH also has more hydrogen by mass in 1L than in a litre of pure liquid hydrogen (98.8 g of H_2 in 1 L of MeOH at room temperature compared to 70.8 g in liquid H_2 at − 253°C) [Ref 17]. Cost-effective system flexibility via the utilisation of multiple energy carriers would be a major linking piece in the climate neutrality solutions puzzle.

Ammonia (NH_3) could also utilise H_2 production when combined with nitrogen, an abundant and easy to obtain element in the atmosphere via air separation units. Diesel-like engines could utilise NH_3 within the shipping sector at even retrofit ships, or also for the production of fertilisers and other chemicals [Ref 18].

Therefore, H_2 production upscaling rightfully enjoys a high attention, due to its as described key direct or indirect use, in even national planning. Denmark, a front runner in renewable electricity production and security of supply (99.99% [Ref 20]), has recently reached an agreement over an ambitious by 2030 PtX strategy aiming to accelerate the development of green fuels, via the investment of 1.25 billion DKK (~0.17 billion €), in the form of government tenders for electrolysis capacity summing up to 4-6GW, while also supporting the potential of PtX production export to third countries [Ref 19]. The utilisation overview of the produced H_2 includes its conversion into other PtX products such as ammonia, methanol or e-kerosene. More advanced PtX products requiring carbon in their formation can obtain it by a large option pool of biogas and biomass fuelled CHP plants producing biogenic CO_2 across Denmark. The 4 Danish objectives laying the foundation for the financing of such ambitious plans can be seen in **Figure 3**.

Figure 3. Danish PtX development objectives by 2030 [Ref 19]

1.5. Goals of The Master's Thesis Project – Research Gap

Since June 2020, Denmark has set solid foundations for pioneering the global green transition and becoming an example towards a greener energy sector and furthermore industry. The signed Climate Aggreement ("Klimaaftalen") providing the green light to the creation the world's first "energy islands", 3GW in the North Sea and 2GW on Bornholm via public-private partnerships [Ref 21]. The generated power will be directed to Denmark and neighbouring countries with the future outlook of enabling technology connections via storage and/or conversion of green power into green fuels, the so called PtX.

The encouragement of private participation in the green transition became evident via the signed Climate Agreement. Incentives such as the national PtX strategy [Ref 19] amplify the call for the acceleration of private investment within the green energy field, with various types of scopes. The latest confirmation of the competitiveness of RES technologies purely on market terms (no subsidies) is evident, by offshore project bids in northern Europe declining for the past years to around a level of 50-70 €/MWh [Ref 7]. The validity of those assumptions of course comes to be sealed with recent zero bid project tenders achieved in German, Dutch and one recent Danish project (Thor), where investors have reached as far as paying penalties to their state, under a 2-way CfD scheme, before actually making any revenues and still being profitable through the project's lifetime.

The future trajectory of electricity prices coupled with the global push for more secure energy supply amidst the aforementioned crises, present a pool of different aim opportunities for private investors. However, decisions ahead are far from simple. High recent electricity market prices would potentially act as a hindrance to the agreement of any viable PPAs between green electricity and PtX fuel producers within the context of an Energy Hub for the foreseeable future. On the other hand, the promising forecasted cost effectiveness potential of such fuels in the near and long term future versus fossil but also 1st and 2nd generation bio-fuels is heavily relying on such agreements (**Figure** *4*). Adding on top the inability of pure electrification for addressing the hard-to-abate sectors, an eye-catching area of research arises.

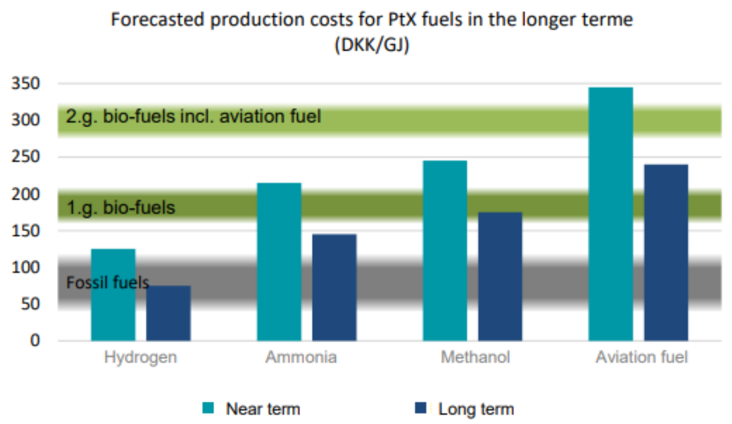


Figure 4. Forecast of PtX production costs [Ref 19]

Change is threatening people as the status quo is being challenged, by leaving people less well off. In periods of radical change as large as the green transition's magnitude, a wide range of opportunities evolves for various calibre's investors, and the approach around them is pivotal to preserve balances between sides and result in an optimal social welfare.

A conservative amount of focus has been up to date given on production of green fuels and consequently the synergies between RES electricity and PtX producers, according to existing literature. Most researchers have focused on a few limited models of EH concepts, focusing heavily on the production of electricity and heat through CHP plants along an evident reliance on natural gas and grid power.

In fact, regardless of energy hubs being a promising concept for years to come, only a limited amount of model and approaches exist in the literature, with no well-rounded one present, i.e. dynamically defining the capacity investments based on the uncertain future operation conditions and the potential agreements between consortium members. For these reasons the present analysis will focus on providing a comprehensive approach towards the derivation of informed decisions adjusted to the overall risk perception and acceptance levels, while ultimately showcasing the present opportunities but also shortcomings in state of the art EH coalitions.

1.6. Summary of Project's Research Questions

I. Which green PtX fuels and at what selling price can balance the opportunity costs that RES generators face from lower spot-market trading when participating in an EH?

II. Can those PtX fuels be competitive in the market in order to sustain a feasible operation of an energy hub for all participants?

III. What the optimal configuration and operation of the energy hub looks like under uncertainty of the day ahead electricity market across a 20 horizon?

IV. What level of internal commodity pricing could the energy hub operate under so it can host profitable investments for its participants?

V. Are the investment decisions made under uncertainty robust across different scenario realisations?

VI. Does the sensitivity of the optimised results prove to be promising for the future of green PtX products through energy hubs?

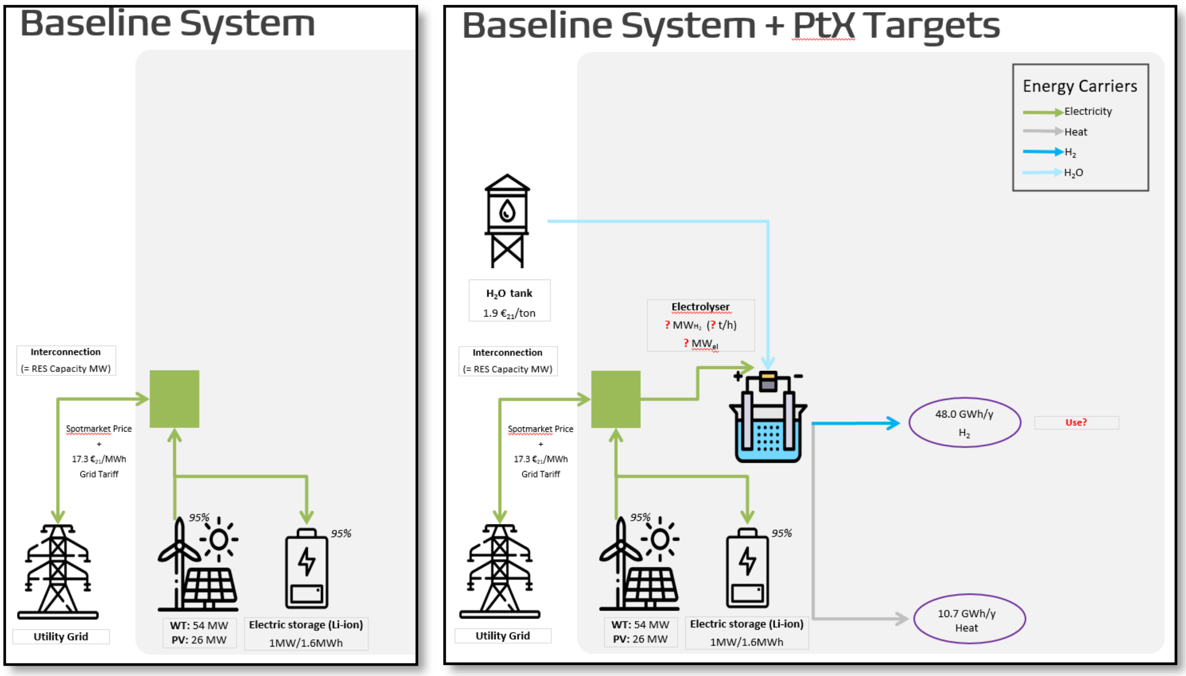
2. Methodology & Assumptions

The present section will illustrate the main assumptions behind the undertaken analysis alongside the key steps which will ultimately lead to a combination of results, feeding the overall analysis. The overarching idea, optimisation via mathematical modelling & supporting material, as well as the drivers of the analysis can be found in the following paragraphs.

2.1. Description of the Under Analysis Energy Hub

A Danish grid-connected version of an Energy Hub consisting of 80MW RES generators (54MW WT, 26MW PV) alongside a 1MW/1.6MWh Li-ion battery, is taken as the analysis basis, hereafter referred to as "Baseline System". From there, a "Baseline System + PtX Targets" case is being assumed [**Figure** *5*], where the EH would be interested to annually operate an Alkaline Electrolyser (AEC) at the annual range of 4000FLH [Ref *32*]. Taking again information from the future plans of the assumed baseline [Project 7: **Figure** *7*], leads to the assumption that at a first step, the electrolyser would rise to $12MW_{H_2}$. With such conditions, the final annual targets of 48GWh of H_2 are being shaped.

By taking those 48GWh of H_2 production, the present project aims to assess the optimal alternative system vs the "Baseline System" from the point of view of an external investor, who would be interested to propose a participation in an EH consortium. In other words, what use would those 48GWh of produced H_2 further have, what should the commodity pricing of the resulting product should in order to balance the opportunity cost of the EH's lessened spot-market trading and of course, what would the optimised capacities of the invested PtX assets be to match all technical synergies. The aforementioned $12MW_{H_2}$ capacity acted as a ruler for the annual production calculations and the actual final EC capacity will be subject to optimisation). A series of potential different investors will be researched and informed decisions will be drawn towards further investigation.



**The drawing's skeleton is courtesy of Ioannis Kountouris' MSc Thesis [Ref 39]*

Figure 5. Energy Hub's baseline and scope

Three PtX technologies (hereafter referred to as “Alternative H_2 User”) will be assessed for potential end-use of the annually produced H_2 targets:

- A methanol synthesis plant (MeOH)
- A compressed H_2 storage (CHS)
- An ammonia synthesis plant (NH_3)

2.2. Stochastic Optimisation

Risk assimilation is one of the most vital elements for investment decisions but also bilateral agreements. Deterministic models tend to consider unrealistically perfect information about a problem’s nature and structure, failing to account for unexpected turn of events which could have a detrimental effect on the examined business case(s).

The global green transition, as thoroughly discussed in Section 1, heavily relies on the observed electricity market prices but also sector coupling. High spot-market prices benefit investments or simple participation of existing assets purely on a grid-connected market, while on the contrary low prices would shift investments towards more profitable energy usage. Adding on top that the usual lifetime of an investment rises to approximately 20 years, it becomes evident that the more an analyst makes use of any quantifiable uncertainty, the more solid and optimised results will be generated.

The main general form principle of Stochastic Optimisation in conjunction with the field of Decision Making Under Uncertainty (DMUU) can be seen below (for a minimisation problem):

$$\min z = c^T x + E_\xi[\min q(\omega)^T y\,(\omega)]$$

(or in its equivalent extensive form: $\min z = c^T x + \sum_{\omega \in \Omega} phi(\omega)\, q(\omega)^T y\,(\omega)$)

Subject to:

$$Ax = b$$

$$T(\omega)x + W(\omega)y(\omega) = h(\omega) \quad \forall\, \omega \in \Omega$$

$$x \geq 0$$

$$y(\omega) \geq 0 \quad \forall\, \omega \in \Omega$$

Where: x and y are the first and second stage decision variables respectively (hereafter referred to as “Here-and-Now” (scenario independent) and “Wait-and-See” (scenario dependent) variables correspondingly), ξ being a random vector containing the uncertain data for T, W, h and q, and ω representing a random event/realization of uncertainty from ξ, with ω ∈ Ω, a finite set of scenarios of uncertainty with probability of realisation phi(ω). Of course the stochastic program can include more than two stages, with the scenario tree increasing accordingly.

Expectedly, the complexity as well as number of constraints and variables increase along the higher scenario inclusion, with the computational demand rising to considerable levels for bigger problems. Further actions usually need to be taken then to alleviate such pressure, like linearisation binary variables, time-aggregation or even decomposition techniques, however such procedures are out of the scope of the present analysis and will not be further explored.

More informed decisions as well as less volatile result realisation across scenarios are only some of the benefits of stochastic programming, as will be extensively explored within the following analysis. On the whole, the benefits of such stochastic models with increased number of scenarios, lies within the draw of one unanimous decision for Here-and-Now variables, in contrast to the process of solving a series of independent deterministic problems and assessing tediously a “good-enough” decision seemingly suitable for all possible scenario realisations.

2.3. Stepwise Optimisation

During the deployment of the present study, an interlinked 3-step optimisation procedure will be followed towards wholistically optimising the EH’s returns in parallel to the investors’ requirements. The full list of steps followed will be briefly introduced below and described thoroughly afterwards:

- **Step 1**: Definition of PtX technological capacities and their off-take pricing ($€_{21}$/MWh).
- **Step 2:** Planning of the optimal EH’s dispatch for the optimised capacities and off-take pricing, in an hourly resolution across the assessed horizon (4 representative years). Internal trading of commodities during the present step is being set to 0 €/MWh, due to aiming to an overall EH welfare. Distribution of profits will take place within the next step.
- **Step 3:** Definition of optimal internal pricing levels (€/MWh) for commodity trading within the EH’s boundaries, and ultimate profit distribution across the investors.

2.3.1. Step 1: Capacities and Off-taker Pricing

In an attempt to both define capacities and an adequate off-taker pricing which would return an equivalent overall monetary value to the EH as the simple RES+Grid setup would do, the “loss” in terms of the opportunity cost that the Baseline System EH experiences has to be quantified. For this reason, while the model would be optimising capacities for both EC and “Alternative H2 User” technologies to produce and utilise those 48GWh of H_2, there will be no monetary return to the system, or in other words the EH will be “selling” these PtX-fuels to 0 $€_{21}$/MWh.

As introduced in paragraph 2.2, the model will attempt to define the best unit investments across the given uncertainty set of DA electricity pricing, making informed decisions via assessing all possible probabilistic combinations and choosing capacities which would serve the model adequately well upon all realisations of scenarios without extremely fluctuating realisations. The balancing of the day-to-day EH operations has been set out of scope for this analysis, due to the fact that the cost-recovery of investment decisions within the Danish reality seem to primarily rely on the DA market, due to the considerably higher traded volumes on that stage of the market [Ref 40].

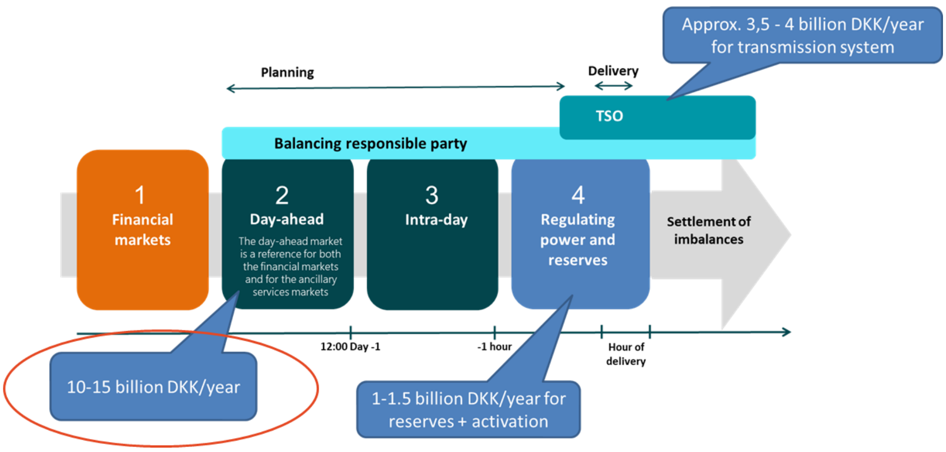


Figure 6. Trading statistics for the Danish electricity market [Ref 40]

2.3.2. Step 2: Dispatch Planning

Due to both Danish but also European-wide tendencies towards ramping up the creation of a solid hydrogen economy by 2030 via rapid installation of electrolysis facilities and subsequently their PtX links [Ref *19* & Ref *15*], the present analysis will cumulatively utilise the capacity results from Step 1 and explore the synergies but also competitive nature of EH's by planning an optimised future dispatch pathway, according to exogenous but also investor-specific constraints. The validity of the assumption of cumulatively defining the final existing unit sizing through Step 1, as will be thoroughly discussed in Section 4, is being confirmed by researching the future plans of the Baseline System's origin [Ref *56*], which entail the installation of a 12MW Electrolysis plant by 2022 and a quick scaling to 24MW soon after, with long term goals of scaling up to 250MW. In parallel, an ambitious EU-funded project will also be developed for a further addition of a 100MW unit by 2024 [Ref *41*].

The force of the analysis will be cost-driven, attempting to minimise the EH's overall costs while also accounting for any revenues resulting from external commodity-trading during the optimal resulting dispatch expectation. The absence of internal pricing on the current step does not affect the overall optimisation's targets of the EH due to the fixed external commodity pricing. Internal pricing is a cost pass-through cashflow from investor to investor and will ultimately simply affect the profit distribution within the EH.

Step 2, practically, does not make any use of the given uncertainty space towards a "Here-and-Now" decision, other than showcasing the best reaction of the EH to the realisation of each DA price signals within each scenario, based on decisions taken already (investments). The resulting from this step "Wait-and-See" variables will be passed on and fixed within step 3 in order to set up the scene for the definition of the internal commodity pricing, which will remain the same across scenarios. **Equation 1** to **Equation 43** will define the acceptable solution space for each scenario and determine the best possible dispatch within scenarios for maximised final returns for the EH as a whole.

2.3.3. Step 3: Internal Pricing and Profit Distribution

The final step of the analysis, Step 3, attempts to define relationships between the coalition members and ultimately distribute the overall profits while respecting all the investor-specific requirements. The definition of an internal commodity pricing will be a product of investor specific constraints, each trying to maximise their final returns.

Such internal pricing relationships are frequently used nowadays between renewable generators and off-takers, with an example being the sourcing of "green" electricity to specific retailers, which will then be claimed by the retailers' end users. Such contracts have frequently the structure of a PPA, usually locking onto a fixed pricing across a range of years while promising a minimum annual level of product delivery [Ref 42]. The specifics of the best-possible definition and structure of such bilateral contracts is out of the scope of the present analysis, however the model will showcase the approximate ideal space of satisfactory for all investors pricing in regards to each internally traded commodity, prior to any minimum deliverable commodity amount to the receiving end of the agreement.

Based on the structure of such principles, the internal pricing will be set at a real level ($€_{21}$/MWh), in contrast to all residual operational costs and external revenues which will be subject to the annual imposed inflation ($€_{nom}$/MWh). Of course, while compiling and evaluating the total cashflows across steps, all values will be brought to their respective nominal level (if applicable) and later get discounted back to the defined evaluation year for more tangible comparisons. Equations **Equation 44** to **Equation 54** will build on top of the previously declared constraints and will define the acceptable solution space for the model by respecting all technical but also economic considerations, with heavy focus on the clause that each investor will have to across scenarios achieve an expected value of NPV≥0. Of course, upon scenario realisation some actors may not achieve to hit their break-even point, nevertheless, the stochastic solution will try to best serve the fed expectation of uncertainty as a whole, and avoid significant fluctuations across the extreme scenario cases.

2.4. Financial Assumptions

A common approach for any given project appraisal is the calculated Net Present Value (NPV) of the project's lifetime cashflows (CF) at a chosen evaluation year. Thus, the current analysis will first calculate the FV equivalent of all cashflows across representative years, and then discount them all to the proposed project evaluation date based on the utilised Weighted Average Cost of Capital. WACC is a metric of an investor's cost of capital, with each source of capital provision being proportionately weighted. Nominal pre-tax WACC values have been utilised throughout the following analysis.

$$\boldsymbol{NPV} = -CF_0 + \sum_{t=1}^{T} \frac{CF_t}{(1+WACC)^t} \qquad \boldsymbol{WACC} = \frac{E}{E+D} * R_e + \frac{D}{E+D} * R_d * (1-T)$$

Where: t signalises each assessed year, E and D are the total Equity and Debt values, Re and Rd the return on equity and debt respectively and T the assumed tax rate.

2.5. Mathematical Model

The present section will aim to give an overview of the development and functionalities of the final model version, alongside the fed sets, parameters as well as utilised variables and occurring relationships (constraints). A brief explanation of each section will be presented, showcasing the main rationale behind the depicted functionalities. The model's development and optimisation take place within the General Algebraic Modelling System (GAMS v30.3.0 [Ref 43]), via CPLEX solver (v20.1.0.1 [Ref 44]), with the resulting program characterised as a Mixed Integer Problem (MIP).

2.5.1. Sets

The sets within which each parameter and variable will be operating, shaping ultimately the feasible solution space can be found **Table 1** and **Table 2**.

Table 1. Modelled sets

Set ID	Set Name	Set Entities
A	Areas	2
T	Technologies	6
E	Energy carriers	11
S	Scenarios	5
Y	Years	4
H	Hours	8760
D	Directions	2

Table 2. Modelled subsets

Subset ID	Subset Information
$A^{in}_{a^{in},a^{out},e} \subset$ A	Energy carriers possible to flow from third areas (out) towards each examined area (in).
$A^{out}_{a^{in},a^{out},e} \subset$ A	Energy carriers possible to flow towards third areas (out) from each examined area (in).
$E^{in}_{t,e} \subset$ E	Used energy by modelled units as fuel
$E^{out}_{t,e} \subset$ E	Produced energy by modelled units
$E^{imp}_{a,e} \subset$ E	Imported energy from third areas
$E^{exp}_{a,e} \subset$ E	Exported energy to third areas
$E^{NP}_{t,e} \subset$ E	Nameplate energy for each technology
$E^{int}_{a,e} \subset$ E	Internally traded energy commodities within each area
$G^{uc}_{t} \subset$ T	Technologies with unit commitment requirements
$G^{st}_{t} \subset$ T	Storing technologies
$G^{gen}_{t} \subset$ T	Generating technologies
$T^{from}_{t} \subset$ T	Origin technology
$T^{to}_{t} \subset$ T	Target Technology

2.5.2. Parameters

Table 3 lists the main entities which consist the data fed to the model, along a short description related to each parameter's details as well as definition dimensions.

Table 3. Model related parameters

Parameter	Description
Energy Related	
$p_{a,e,d,s,y,h}$	Hourly commodity pricing for each modelled energy carrier $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$ according to the direction of flow $d \in D$ from area $a \in A$
$tf_{a,e,s,y,h}$	Tariff liability per unit of imported energy carrier $e \in E$ within area $a \in A$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$
$fu^{bound}_{a,e,d,s,y,h}$	Upper bound of energy carrier $e \in E$ availability in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$ according to the direction of flow $d \in D$ from area $a \in A$
$x_{a,e,s,y,h}$	Total interconnector capacity in respect to each energy carrier $e \in E$ within area $a \in A$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$
Unit Related	
$cm_{t,d,e}$	Carrier mix parameter, indicating the balance equation for each modelled unit $t \in T$, incorporating all modelled energy carriers $e \in E$ based on their direction of use d ∈ D (use: in, production: out)
fe_t	"Effectiveness" of each assessed unit $t \in T$ taking into account the ratio of total units of output(s) divided by the total units of input(s) (unitless)
$GC^{ex}_{a,t}$	Overall existing input-based capacity in unit tG^{gen}_t activity level within area $a \in A$
$SC^{ex}_{a,t}$	Overall existing input-based storage capacity in unit $t \in G^{st}_t$ within area $a \in A$
$SR^{ex}_{a,t}$	Overall existing hourly storage power rating for each unit $t \in G^{st}_t$ within area $a \in A$
$cf_{t,s,y,h}$	Hourly profiles for each modelled technology $t \in T$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$
$cap^{up,NP}_{a,t}$	Total capacity restrictions in respect to the nameplate energy carrier for each modelled technology $t \in T$ within each area $a \in A$
$cap^{lo,NP}_{a,t}$	Total capacity restrictions in respect to the minimum levels of nameplate capacity for each modelled technology $t \in T$ within each area $a \in A$
ml_t	Minimum operating load requirements as a percentage of the operating capacity for each assessed unit $t \in T$ taking
rr_t	Ramping rate as a percentage of the operating capacity for each assessed unit $t \in T$ taking
$G^{\%}_{a,t,e,s,y,h}$	Generation contribution of each $t \in T$ within area $a \in A$ of energy carrier $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$ from internal commodity sourcing
$FU^{\%}_{a,t,e,s,y,h}$	Fuel use contribution each unit $t \in T$ within area $a \in A$ of energy carrier $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$ from internal commodity sourcing
sq^{NP}_t	Spacing requirements per nameplate capacity for each modelled technology t ∈ T

Parameter	Description
sq_a	Total areal availability within each area $a \in A$
$c_t^{CAPEX,NM}$	Capital expenditure per MW of nameplate capacity for each modelled technology $t \in T$
$c_t^{fO\&M,NM}$	Fixed annual O&M costs per MW of nameplate capacity for each modelled technology $t \in T$
$c_t^{vO\&M,NM}$	Variable O&M costs per MWh of nameplate energy production for each modelled technology $t \in T$
c_t^{start}	Start-up costs for each modelled technology $t \in T$
$FLH_{t,e}$	Annual FLH targets per technology $t \in T$ and energy carrier $e \in E$
Financially Related	
$WACC_t$	Weighted Average Cost of Capital for each modelled technology $t \in T$
CRF	Capital Recovery Factor (assisting the annuitisation of each unit's CAPEX)
DF_y	Discounting factor from each future year's cashflow to the evaluation year
DR	Annual depreciation rate of assets (straight line)
CTR	Corporate tax rate
i_y	Inflation index of each respective year against the model's base year
Uncertainty Related	
phi_s	Scenario probability of realisation for each modelled scenario $s \in S$

2.5.3. Variables

Lastly, the variables which will act as the main vehicles of each problem's optimised solution are listed in **Table 4**.

Table 4. Model related variables

Variable	Description	Type
Financially Related		
Obj	Expectation of the system's monetary balance	Free ($\in$ R)
TR	Expectation of the system's total revenues	Free ($\in$ R)
TC	Expectation of the system's total costs	Free ($\in$ R)
$Z_{s,y}$	System's monetary balance per scenario $s \in S$ and year $y \in Y$	Free ($\in$ R)
$R_{s,y}$	System's revenues per scenario $s \in S$ and year $y \in Y$	Free ($\in$ R)
$C_{s,y}$	System's costs per scenario $s \in S$ and year $y \in Y$	Free ($\in$ R)

Variable	Description	Type
$EBITDA_{a,t,s,y}$	Earnings Before Taxes for each unit $t \in T$ within area $a \in A$ in each scenario $s \in S$ and year $y \in Y$	Free (∈ R)
$Tax_{a,t,s,y}$	Taxes for each unit $t \in T$ within area $a \in A$ in each scenario $s \in S$ and year $y \in Y$	Free (∈ R$^+$)
$AD_{a,t,s,y}$	Annual depreciation for each unit $t \in T$ within area $a \in A$ in each scenario $s \in S$ and year $y \in Y$	Free (∈ R$^+$)
$Cash_{a,t,s,y}^{FV}$	Annual cashflow for each unit $t \in T$ within area $a \in A$ in each scenario $s \in S$ and year $y \in Y$ (future value - nominal)	Free (∈ R)
$Cash_{a,t,s,y}^{PV}$	Annual cashflow for each unit $t \in T$ within area $a \in A$ in each scenario $s \in S$ and year $y \in Y$ (present value – discounted to evaluation date)	Free (∈ R)
$NPV_{a,t,s}$	Net Present Value for each unit $t \in T$ within area $a \in A$ in each scenario $s \in S$	Free (∈ R)
$TR_{a,t,e,s,y,h}^{unit}$	Total unit specific revenues for each unit $t \in T$ within area $a \in A$ from energy carrier $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative (∈ R$^+$)
$R_{a,t,e,s,y,h}^{unit,int}$	Unit specific revenues for each unit $t \in T$ within area $a \in A$ from energy carrier $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$ from internal commodity trading	Non-negative (∈ R$^+$)
$R_{a,t,e,s,y,h}^{unit,ext}$	Unit specific revenues for each unit $t \in T$ within area $a \in A$ from energy carrier $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$ from external commodity trading	Non-negative (∈ R$^+$)
$TC_{a,t,e,s,y,h}^{unit}$	Total unit specific costs for each unit $t \in T$ within area $a \in A$ from energy carrier $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative (∈ R$^+$)
$C_{a,t,e,s,y,h}^{unit,int}$	Unit specific costs for each unit $t \in T$ within area $a \in A$ from energy carrier $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$ from internal commodity sourcing	Non-negative (∈ R$^+$)
$C_{a,t,e,s,y,h}^{unit,ext}$	Unit specific costs for each unit $t \in T$ within area $a \in A$ from energy carrier $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$ from external commodity sourcing	Non-negative (∈ R$^+$)
$C_{a,t,s,y,h}^{unit,start}$	Unit specific start-up costs for each unit $t \in T$ within area $a \in A$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative (∈ R+)
$P_{a,t,t,e}^{int}$	Internal commodity pricing from each unit $t \in T$ to another within area $a \in A$ for energy carrier $e \in E$	Non-negative (∈ R$^+$)
$P_{a,t,e}^{comp}$	Slack variable acting as the necessary compensation of each unit $t \in T$ in area $a \in A$ for its nameplate energy carrier $e \in E_{t,e}^{NP}$, in order to bring the unit's EBT expectation across scenarios and years to ≥ 0	Non-negative (∈ R$^+$)

Variable	Description	Type
Energy Related		
$TA_{a,t,s,y,h}$	Total unit specific level of energy activity for each unit $t \in T$ within area $a \in A$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$ f (unitless)	Non-negative ($\in R^+$)
$FL^{ext}_{a,a,e,s,y,h}$	Area to area energy flows for areas $a \in A$ of energy carriers $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative ($\in R^+$)
$B^{ext}_{a,e,s,y,h}$	Externally purchased energy levels from area $a \in A$ of energy carriers $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative ($\in R^+$)
$S^{ext}_{a,e,s,y,h}$	Externally sold energy levels from area $a \in A$ of energy carriers $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative ($\in R^+$)
$C^{tar}_{a,e,s,y,h}$	Tariff liability attributed to inflows of energy carriers in area $a \in A$ of energy carriers $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative ($\in R^+$)
$B^{int}_{a,e,s,y,h}$	Internally purchased energy levels within area $a \in A$ of energy carriers $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative ($\in R^+$)
$S^{int}_{a,e,s,y,h}$	Internally sold energy levels within area $a \in A$ of energy carriers $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative ($\in R^+$)
Unit Related		
$G_{a,t,e,s,y,h}$	Unit specific generation levels for each unit $t \in T$ within area $a \in A$ of energy carrier $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$ from internal commodity sourcing	Non-negative ($\in R^+$)
$FU_{a,t,e,s,y,h}$	Unit specific energy use levels for each unit $t \in T$ within area $a \in A$ of energy carrier $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$ from internal commodity sourcing	Non-negative ($\in R^+$)
$V_{a,t,e,s,y,h}$	Storage specific volume levels for each unit $t \in G^{st}$ within area $a \in A$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative ($\in R^+$)
$B^{unit,int}_{a,t,e,s,y,h}$	Internally purchased energy levels from each unit $t \in T$ within area $a \in A$ of energy carriers $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative ($\in R^+$)
$S^{unit,int}_{a,t,e,s,y,h}$	Internally sold energy levels from each unit $t \in T$ within area $a \in A$ of energy carriers $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative ($\in R^+$)
$FL^{unit,int}_{a,t,t,e,s,y,h}$	Internal energy flows from technology $t \in T$ to technology $t \in T$ within areas $a \in A$ of energy carriers $e \in E$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative ($\in R^+$)
$GC^{inv}_{a,t}$	Overall invested output-based capacity in unit $t \in G^{gen}_t$ activity level within area $a \in A$	Non-negative ($\in R^+$)
$SC^{inv}_{a,t}$	Overall invested output-based storage capacity in unit $t \in G^{st}_t$	Non-negative

Variable	**Description**	**Type**
	within area $a \in A$	($\in \mathbb{R}^{+}$)
$SR_{a,t}^{inv}$	Overall invested hourly storage power rating for each unit $t \in G_t^{st}$ within area $a \in A$	Non-negative ($\in \mathbb{R}^{+}$)
$GC_{a,t}^{NP}$	Total capacity in respect to each technology's $t \in T$ nameplate energy carrier within area $a \in A$	Non-negative ($\in \mathbb{R}^{+}$)
$GC_{a,t}^{NP,ex}$	Existing capacity in respect to each technology's $t \in T$ nameplate energy carrier within area $a \in A$	Non-negative ($\in \mathbb{R}^{+}$)
$GC_{a,t}^{NP,inv}$	Invested capacity in respect to each technology's $t \in T$ nameplate energy carrier within area $a \in A$	Non-negative ($\in \mathbb{R}^{+}$)
$TAEC_{a,t,s,y}$	Total Annual Economic Cost for each unit $t \in T$ within area $a \in A$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative ($\in \mathbb{R}^{+}$)
$LCOE_{a,t,s,y}^{NP}$	Levelised Cost of nameplate Energy for each unit $t \in T$ within area $a \in A$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative ($\in \mathbb{R}^{+}$)
$FLH_{a,t,s,y}^{NP}$	Full Load Hours operation equivalent for each unit $t \in T$ within area $a \in A$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Non-negative ($\in \mathbb{R}^{+}$)
$SQ_{a,t}$	Occupied space from each technology's $t \in T$ within area $a \in A$	Non-negative ($\in \mathbb{R}^{+}$)
$On_{a,t,s,y,h}$	Status variable indicating the activity or inactivity for each unit $t \in T$ within area $a \in A$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Binary ($\in \{0,1\}$)
$Ch_{a,t,s,y,h}$	Status variable indicating the charging activity for each unit $t \in G^{St}$ within area $a \in A$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Binary ($\in \{0,1\}$)
$Dis_{a,t,s,y,h}$	Status variable indicating the discharging activity for each unit $t \in G^{St}$ within area $a \in A$ in each scenario $s \in S$, year $y \in Y$ and hour $h \in H$	Binary ($\in \{0,1\}$)

2.5.4. Mathematical Formulation

Following the step-wise approach presented in paragraph 2.3, the present paragraph illustrates all mathematical relationships shaping the feasible solution space(s) for each model run. Any pre-existing and unchanged part of the model [Ref *39*] will be highlighted by **blue font**, while all modifications and additions will be listed in the common black font utilised across the report. It has to be noted that not all parts of the model are utilised in each model run, with specific variables being fixed to pre-determined values (ultimately acting as parameters) according to the undertaken optimisation step, preserving the linear character of the optimisation at all points.

Objective function

The goal of the present model is the minimisation of the expected value of the EH's total costs across years and scenarios, while also accounting for all revenue streams. In other words, the objective of the model is to maximise the revenue of the EH as a whole, while satisfying all applied constraints and requirements. $R_{s,y}$ accounts for the realisation of both external and internal revenue streams for all modelled units across years in each scenario, while $C_{s,y}$ on the contrary takes into consideration all annual expenses and liabilities, but also the annuitisation of the CAPEX in equal distinct "instalments" across all of the EH's lifetime.

It is of course worth mentioning that the present analysis reflects the results of 4 milestone years (2025, 2030, 2035, 2040), with the assumption that the evaluation year matches the end of the year before COD. It becomes apparent then that the modelled results incorporate representative cashflows for those years only, while practically assuming a total of 20y horizon for the present investment.

$$\min_{\Omega} \quad Obj = \sum_{s \in S} phi_s \cdot \left(\sum_{y \in Y} DF_y \cdot (C_{s,y} - R_{s,y}) \right) \qquad \text{Equation 1}$$

where: $\Omega = \{ R_{s,y}, C_{s,y}, C^{unit,start}_{a,t,s,y,h}, TA_{a,t,s,y,h}, FL^{ext}_{a,a,e,s,y,h}, B^{ext}_{a,e,s,y,h}, S^{ext}_{a,e,s,y,h}, C^{tar}_{a,e,s,y,h}, G_{a,t,e,s,y,h}, FU_{a,t,e,s,y,h}, V_{a,t,e,s,y,h}, GC^{inv}_{a,t}, SC^{inv}_{a,t}, GC^{NP}_{a,t}, SQ_{a,t}, On_{a,t,s,y,h}, Ch_{a,t,s,y,h}, Dis_{a,t,s,y,h} \}$.

Subject to: Equation 2 to Equation 54.

$$R_{s,y} = \sum_{a,e \in E^{exp}_a, h} p_{a,e,d,s,y,h} \cdot S^{ext}_{a,e,s,y,h} \cdot i_y + \sum_{a,t,e \in E^{int}_a, h} \sum_{t^{to}} (S^{unit,int}_{a,e,s,y,h} \cdot P^{int}_{a,t,t^{to},e}) \qquad \forall s,y,\ d = exp \qquad \text{Equation 2}$$

$$\begin{aligned} C_{s,y} = & \sum_{a,t} CRF \cdot GC^{NP}_{a,t} \cdot c^{CAPEX,NM}_t \\ & + \sum_{a,e \in E^{imp}_a, h} p_{a,e,d,s,y,h} \cdot S^{ext}_{a,e,s,y,h} \cdot i_y + \sum_{a,t,e \in E^{int}_a, h} \sum_{t^{to}} (S^{unit,int}_{a,e,s,y,h} \cdot P^{int}_{a,t,t^{to},e}) \\ & + \sum_{a,t} GC^{NP}_{a,t} \cdot c^{fO\&M,NM}_t \cdot i_y + \sum_{a,t,e \in E^{NM}_t} G_{a,t,e,s,y,h} \cdot c^{vO\&M,NM}_t \cdot i_y \\ & + \sum_{a,e,h} C^{tar}_{a,e,s,y,h} + \sum_{a,t,h} C^{unit,start}_{a,t,s,y,h} + \sum_{a,t,e \in E^{NP}_t, h} G_{a,t,e,s,y,h} \cdot P^{comp}_{a,t,e} \end{aligned} \qquad \forall s,y,\ d = imp \qquad \text{Equation 3}$$

Main model-operating principle

The rationale behind the energy specific model operation is based on the calculation of the total energy carrier consumption of each unit in any given hour (hereafter referred to as "Total Activity ($TA_{a,t,s,y,h}$)"). The composition of each unit's "fuels" and "products" is reflected within the "CarrierMix" parameter ($cm_{t,d=in,e} = \frac{cm_{t,d=in,e}}{\sum_{e \in E^{in}_t} cm_{t,d=in,e}}$ and $cm_{t,d=out,e} = \frac{cm_{t,d=out,e}}{\sum_{e \in E^{out}_t} cm_{t,d=out,e}}$) which simply showcases the unitless consistency of all inputs and outputs for any unit in a manner of percentages. On top of that, the parameter "Effectiveness" ($fe_t = \frac{\sum_{e \in E^{out}_t} cm_{t,d=out,e}}{\sum_{e \in E^{in}_t} cm_{t,d=in,e}}$) reflects the modelled unitless "efficiency" of any given reaction, accounting for transformation losses as well as energy carriers not accounted within the present analysis, for the chosen unit specific reaction shown in **Table 5**. Based on those values the CarrierMix value regarding the outflow of H_2 from the electrolyser rises to $cm_{EC,d=out,H_2} = \frac{33.36}{33.36+7.46} = 0.817$, while the unitless modelled "efficiency" Effeciveness to $fe_{EC} = \frac{33.36+7.46}{51+9} = 0.68$.

Table 5. Unit specific balances

Technology	*MWh* Wind	*MWh* Solar	*MWh* Electricity	*MWh* H_2	*Tons* CO_2	*Tons* N_2	*Tons* H_2O	Source
Inflows								
Electric Storage			1.00					*Ref 22*
Electrolysis			51.00				9.00	*Ref 22* *Ref 25* *Ref 26*
Hydrogen Storage			3.00	33.36				*Ref 23*
Methanol Synthesis			0.17	6.67	1.46			*Ref 23* *Ref 27* *Ref 28*
Solar PV		1.00						*Ref 22*
Wind Turbine	1.00							*Ref 22*
Ammonia Synthesis			0.32	6.08		0.84		*Ref 23*

Technology	*MWh* Electricity	*MWh* H_2[1]	*MWh* Compressed H_2	*MWh* MeOH[2]	*MWh* NH_3[3]	*MWh* Heat	Source
Outflows							
Electric Storage	0.95						*Ref 22*
Electrolysis		33.36				7.46	*Ref 22* *Ref 25* *Ref 26*
Hydrogen Storage			30.36				*Ref 23*
Methanol Synthesis				5.54		2.07	*Ref 23* *Ref 27* *Ref 28*
Solar PV	0.95						*Ref 22*
Wind Turbine	0.95						*Ref 22*
Ammonia Synthesis					5.25	0.26	*Ref 23*

[1,2,3]*Assumed LHVs: 120.1MJ/kg$_{H_2}$, 19.93MJ/kg$_{MeOH}$, 18.90MJ/kg$_{NH_3}$*

The same principle applies to also each unit's capacity value. Existing unit capacities are inserted as their overall output-based capacity equivalent ($GC^{ex}_{a,t}$ *and* $SC^{ex}_{a,t}$ / $SR^{ex}_{a,t}$) matching an overall hourly production of their key-representative output energy carrier (nameplate energy) after any occurred losses. In an attempt of simplicity, the more tangible term "NamePlate" ($GC^{NP,ex}_{a,t} = GC^{ex}_{a,t} \cdot cm_{t,d=out,e\in E^{NP}_t}$) will also be calculated/utilised within the present analysis, expressing the unit's capacity in respect to its nameplate energy carrier. The assumed unit specific nameplate capacities are expressed in terms of the energy carriers shown in **Table 6**. Indicatively, for the showcased Electrolyser in **Table 5**, $GC^{ex}_{a,t} = 33.36 + 7.46 = 40.82$ and $GC^{NP,ex}_{a,t} = GC^{ex}_{a,t} \cdot 0.817 = 33.36$.

Table 6. Unit specific nameplate energy carriers

Technology	Energy Carrier^{NP}
Electric Storage	Electricity
Electrolysis	Hydrogen (H_2)
Hydrogen Storage	Hydrogen (H_2)
Methanol Synthesis	Methanol (MeOH)
Solar PV	Electricity
Wind Turbine	Electricity
Ammonia Synthesis	Ammonia (NH_3)

Capacity constraints

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Generation technologies' technical constraints

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Storage technologies' technical constraints

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Energy constraints

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Unit commitment constraints

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Internal trading

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Economics

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Investment Evaluation

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2.6. Model limitations

It becomes evident that approaching such a complicated aspect as an EH from both investment but also operational aspects, while later aiming to also evaluate its financial feasibility and create an attractive environment for all investors, comes with many caveats. As presented, one size doesn't fit all, and the model has to be split in a stepwise optimisation to preserve its linearity and keep its operationality. Additionally, computational issues exponentially rise with such highly detailed hourly runs, but also with the inclusion of binary variables during investment optimisations. On top, probabilistic approaches and the inclusion of uncertainty spike the computational burden even further. For such reasons, the model has to operate and present results based on the operation of only representative years, in order to alleviate the pressure and speed up the analysis but also be practical for future use. Interpolation of the resulting cashflow results can shape more tangible final monetary outcomes.

Furthermore, with an MSc Thesis span rising to only 6 months, it is to be expected that assumptions had to be drawn, as presented across the report, and that specific elements will be diodes to future research enrichening the approach over such analyses. Due to the aforementioned computational hindrances, the range of the desired sensitivity analyses testing the model's robustness against apparent drivers had to remain limited, with examinations just listed for future reference. Nevertheless, the final results will more than certainly consist a solid base, able to bring potential investors on the same table and initiate discussions.

Last but not least, such a wide model utilises a big range of data, with many of them being derived from up-to-date literature. It is to be expected that case specific results may vary based on the best available financial, economic and technical conditions.

3. Data

Accompanying the previously described methodology and assumptions, some main parameters and their use will be presented in the upcoming paragraphs. All included data has been derived by credible sources, with any parallel assumptions and corresponding reasoning pinpointed throughout the respective sections. With the rapid fluctuations over the shape and level of the observed spot-market electricity prices since the Covid-19 recovery period, no other data would be more important to evaluate and present insights for. Thus the present study will revolve around the importance of such DA data and the effects on future investment decisions.

3.1. Day Ahead Electricity Market Prices

Structuring an evidently price driven model, while aiming to account for any uncertain price volatility, calls for the utilisation of probabilistic price forecasts. In the present case, the western Danish day-ahead bidding zone (DK_1/DK_{West}) is being considered the target key dataset, primarily due to the considerably higher number of planned PtX plants [**Figure** *7*] which could find immediate use of the developed methodology and insights.

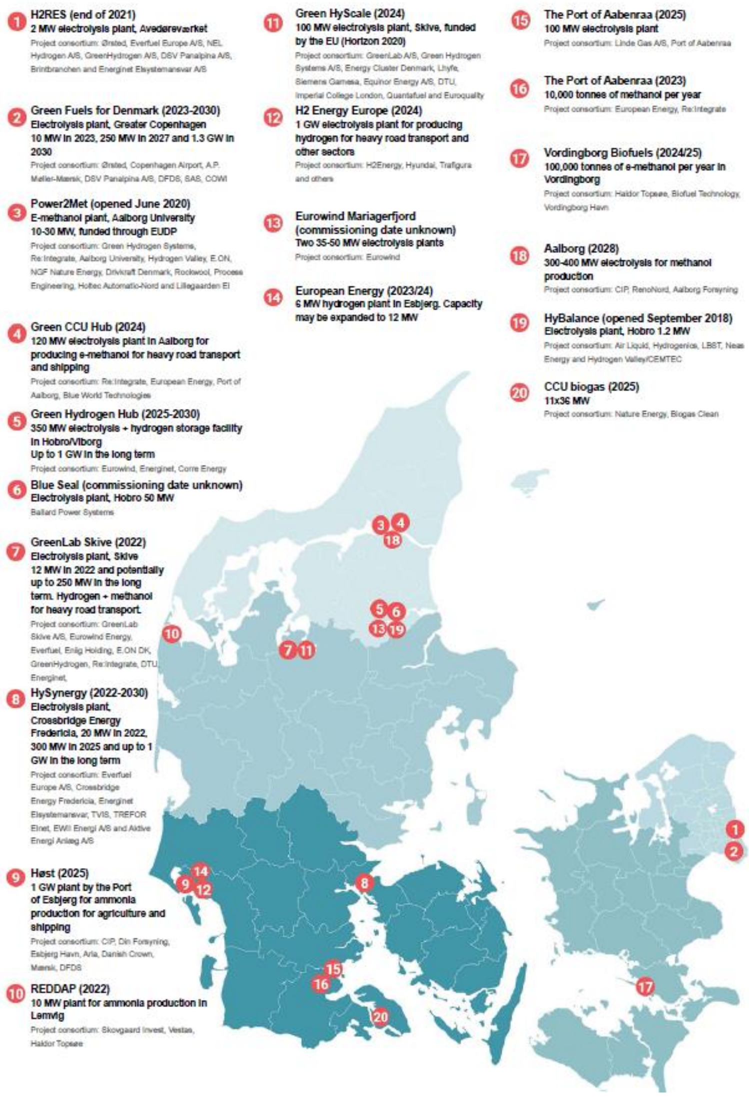

Figure 7. Planned Danish PtX plants by 2030 [Ref 19]

Following the methodology presented in paragraph 2.2, DA electricity market pricing is being set as the carrier of stochasticity, on quite a detailed manner through an hourly resolution. In an attempt to reduce the computational load of the optimisation model, 4 milestone/representative years (2025, 2030, 2035, 2040) are getting placed under the microscope, via which the EH's lifetime operation will be represented. Conclusions for the whole length of the 20-year period will be drawn via interpolating results around those milestone years.

5 distinctive scenarios, reflecting future electricity market tendencies according to the corresponding scenario assumptions vs the determined baseline are utilised, prepared by Ea Energy Analyses [Ref *46*], the company that the present project is being developed in collaboration with. Those scenarios have been prepared in July 2022, utilising as a baseline the most recent electricity market conditions in Denmark. Current price surges are expected to have significant effects in 2025, with their future outlook depending on commodity prices and options for the increased roll-out of RE buildout. The assumed 2022 baseline reflects a

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The impact of such assumptions on the shape of each scenario's price duration curve (PDC) and furthermore the duration of high market prices is illustrated in **Figure *8***. Due to the time-value of money, years closer to the chosen evaluation date (end of 2024) more significantly impact the whole business case due to discounting effects. Thus, even though all scenarios are noticeably converging from 2035 and on towards lower prices, the eye-catching differences between them in previous years will ultimately have a decisive role on final decisions. Of course, lower prices towards the back end of the assessment period will undeniable also shape the derived optimised choices and Wait-and-See decisions (dispatch).

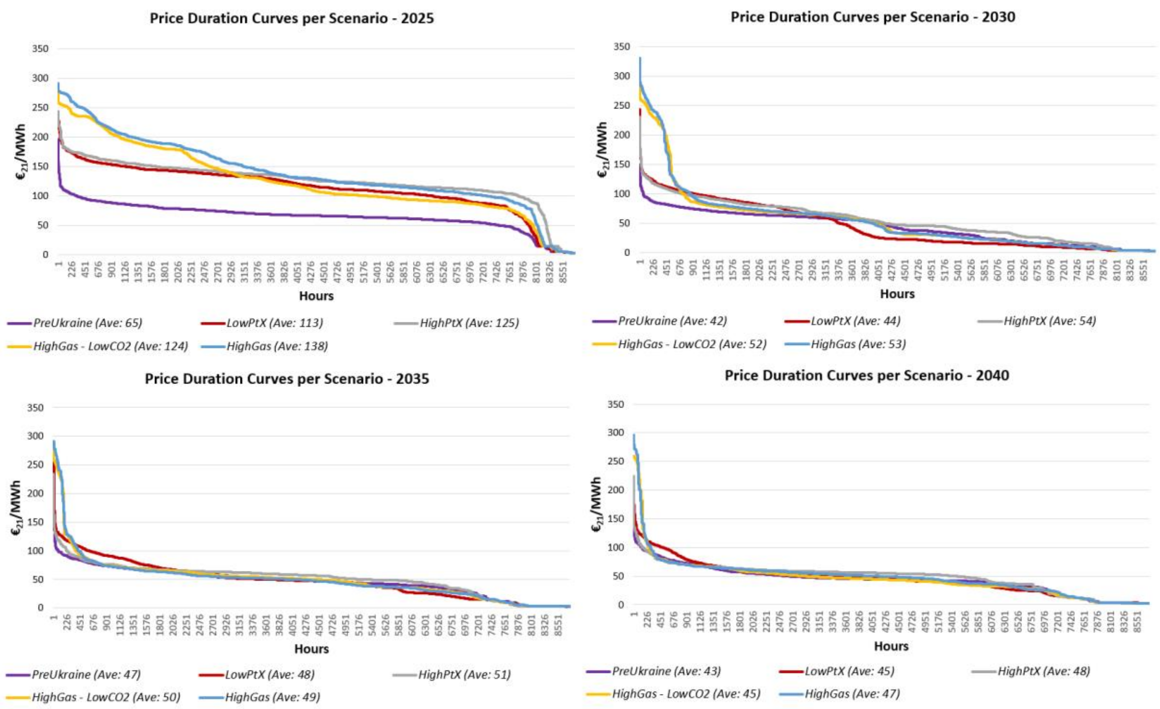


Figure 8. Scenario based price duration curves

3.2. RES Profiles

With the ultimate decisions for the EH's operation being primarily focused on the most profitable way of utilising the internal resources, it is apparent that the annual FLH of the RES generators as well as the distribution of those FLH across the year (profiles) will be the main driver of the EH's decisions when combined with the DA profiles.

Those RES profiles reflect both the quality of the local ambient power potential for the chosen technologies but also the quality of the technological parts comprising the generator. For the present research project, a forecast of 2025 technological development has been utilised for the analysed site, reflecting approximately the location of "Project 7" from **Figure 7**. Those profiles, similarly to the DA price scenarios, have been provided by Ea Energy Analyses as used during their experienced Balmorel modelling [Ref 47]. The expected FLH rise to 3,097 for the onshore wind technology (WT), while to 1,156 for the photovoltaics (PV). With both of the WT and PV capacities not being subject to optimisation (exogenously fixed) but matching those of the aforementioned project (54 and 26 MW respectively), the deterministic annual electricity production rises to 187.4 GWh/y when assuming 95% efficiency due to transmission & conversion losses, with its annual distribution illustrated in **Figure 9**. The fixed interconnector capacity to the grid, allowing hourly electricity imports and exports, has been matched to 100% of the RES capacities.

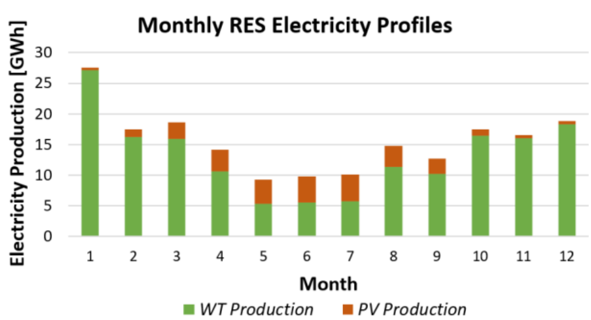


Figure 9. Monthly RES generation profile

3.3. Technical Data

The main technology related data across the pre-existing and for-investment candidates are presented below in **Table 9**.

Table 9. Key technical data

Technology	Minimum Load Level [% MW][1] [Ref 23]	Ramping Rate [% MW/h] [Ref 23]	Lifetime [y] [Ref 22, Ref 23, Ref 24]	Construction Duration [y] [Ref 22, Ref 23, Ref 24]	Spacing Requirements [k.m^2/MW or MWh][2] [Ref 22, Ref 23, Ref 24]
Electric Storage	-	-	20	1	0.01
Electrolysis	20%	50%	26	1	0.02
Hydrogen Storage	-	-	26	1	0.003
Methanol Synthesis	20%	-	21	2	3.00
Solar PV	-	-	35	1	15.67
Wind Turbine	-	-	27	2	0.64
Ammonia Synthesis	20%	20%	30	2	0.05

[1]when online, [2]m^2/MW for non-storage technologies, m^2/MWh for storage technologies

Both minimum load and ramp rate parameters reflect the regulation ability of less flexible units. Start-up times under the considered “warm operation” have been negligible for an hour-to-hour analysis (rising from seconds to minutes) according to the source of information, and thus not considered in the current analysis. Cold start-up times are significantly longer after extended shut-down periods, thus idle operation (unit held at operating temperature) of plants governed by such requirements is suggested and covered by the fixed O&M costs in the present analysis. All PtX fuel generators are highly dependent to the electrolysis unit operation. While MeOH synthesis plants can in general follow the flexibility of the electrolyser, NH_3 synthesis plants are less flexible, and this is reflected in their ramping rate differences [Ref 23].

The construction duration reflects the time from the moment of Final Investment Decision (FID), assuming direct kick-off of construction works, until the commission has been completed (Commercial Operation Date – COD). Those construction durations are assumed to stay the same for the analysed EH size, as a parallel increase of supply-chain sourcing as well as manpower and rise of installed MW is assumed. 100,000 FLH are considered as the Electrolyser’s lifetime potential equivalent, before any stack replacement necessities which will considerably rise the overall CAPEX are needed [Ref 23].

Spacing restrictions reflect two main aspects. From the one hand, the total installed capacities should evidently not surpass the overall available space within the EH. For the available spacing, “Project 7” [**Figure 7**] data are utilised, with existing 600,000m^2 plus recently purchased 700,000m^2 comprising the final available surface. On top, specific stored energy carrier levels cannot cumulatively exceed pre-determined on-site levels, due to safety related allowances. For the present analysis, a limit of 5 tons of compressed H_2 is followed, corresponding to a maximum tank installation of 166.81 MWh, according to Ea Energy Analyses.

On a more general basis, total consumption of the produced outputs has been assumed, paired with a constant availability of utilised by the plants inputs. Such an assumption can be considered acceptable on such a capacity investment optimisation, due to all of the necessary inputs for the pool of technology candidates shown in **Table 5** being common commodities rarely in scarcity for the examined EH’s location. The total consumption of all produced e-fuel outputs is also a valid assumption for such kind of study, as economies of scale usually supress the fuel production costs and furthermore boost the competitiveness of those in a liberal market. Thus, researching maximum possible outputs showcases ultimately the under research question viability of each business case.

Last but not least, as the presented analysis mostly focuses on the gird-vs-internal electricity use, the heat output from all technologies is being collected and assumed to be getting sold at a fixed price of low quality heat, expecting the presence of an external further T° lift via heat-pumps when coupled with its end users, e.g. district heating systems. Waste heat from electrolysis is assumed to be rising to approximately 70°C, while a lower heat quality is assumed for both MeOH and NH_3 synthesis plants (30-60°C) [Ref 23]. No internal circulation of heat has been considered. O_2 production and sale has also been disregarded. Both heat and H_2O selling prices have been shaped by inputs from Ea Energy Analyses.

3.4. Economic Data

With the development and operation of a cost driven model, the assumptions over the costing for all considered entities consists one of the most important aspects. **Table *10*** showcases those assumptions as well as the necessary sources backing those data up. Start-up as well as costs for idle operation status preservation costs (where applicable) are included within the listed fixed O&M costs. All values have been brought to a 2021 price level, while reflecting the technological forecast for their construction year (COD-Construction Duration).

Table 10. Key economic data

Technology	CAPEX [mil. €21/MW][1]	Fixed O&M [€21/MW.y]	Var O&M [€21/MWh]	Reference
Electric Storage	0.98	608.13	2.16	*Ref 24*
Electrolysis	0.56[2]	11,121.99	- [6]	*Ref 23*, *Ref 29*
Hydrogen Storage	0.06	630.65	-	*Ref 24*
Methanol Synthesis	1.42[3]	- [5]	14.24	*Ref 23*, *Ref 30*
Solar PV	0.50	10,791.60	-	*Ref 22*
Wind Turbine	1.23	15,293.29	1.64	*Ref 22*
Ammonia Synthesis	1.67[4]	45,888.71	0.02	*Ref 23*, *Ref 31*

[1]total installed costs, [2]AEC, [3]average of reported projects with purchased carbon source, [4]a specific investment mark-up factor of 1.09 for the inclusion of an ASU has been considered, [5]Included in Var O&M, [6]Included in Fixed O&M.

Aside of those technology-specific costs, some main additional costs used across the optimisation are:

- Grid tariff^{imports}: 17.34 €21/MWh [Ref 48]
- $H_2O^{purchase}$: 1.88 €21/ton
- $CO_2^{purchase}$: 25.00 €21/ton [Ref 30]
- Waste heat$^{sale\text{-}generalised}$: 14.52 €21/MWh

3.5. Financial Data

Evaluating the business case from each investor's point of view, requires having a common comparison base across all projects. In an attempt to achieve that, following the methodology presented in paragraph 2.4, data shown in **Table *11*** are fed to the model, ultimately shaping the final results.

Table 11. Key financial data

Element	Value	Comments	Reference
Inflation Rate	2.00 %/y	European union long term rate	Ref 33
Corporate Tax Rate	22.00 %	-	Ref 34
Depreciation	5 %	Straight line across the 20y horizon	-
Valuation Year	2024 (End)	-	-
Commercial Operation Date (COD)	2025	-	-
Assessment Horizon	20 y	-	-

Due to the existing part of the model operating the EH as a whole for its grid interactions rather than on a unit-to-unit basis, it has been impossible to also adjust such functionality within the MSc Thesis timeframe but also develop the illustrated methodology. For such reasons a commonly used Weighted Average Cost of Capital (WACC) is utilised across all technologies (6.7%), reflecting the average nominal & after-tax WACC of all individual units [Table *12*]. This directly corresponds to same annuitisation factors (CRF) and future discounting across investors, something that has to be kept in mind before final conclusions. Where sources provided a nominal after-tax WACC, conversion to pre-tax values has taken place via: $WACC^{Pre-tax} = \frac{WACC^{After-tax}}{(1-Tax\ Rate\%)}$.

Table 12. Unit specific nominal & pre-tax WACC

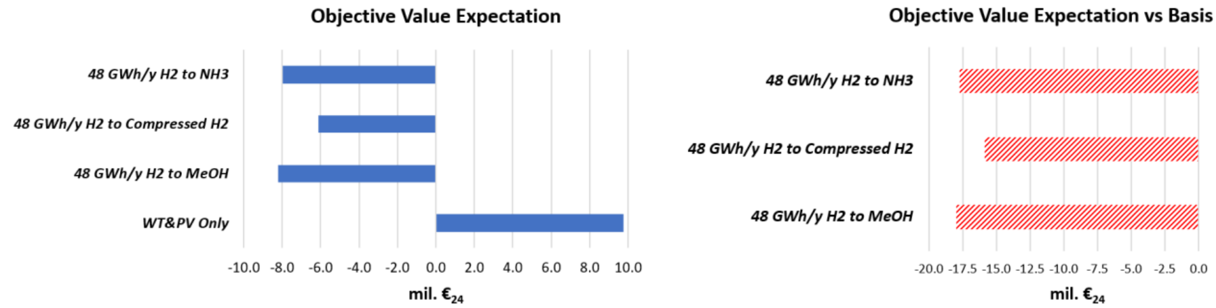
Technology	WACC	Comments	Reference
Electric Storage	5 %	Average of WT and PV	-
Electrolysis	8 %	Average of given range	*Ref 32*
Hydrogen Storage	8 %	Same as electrolysis	-
Methanol Synthesis	8 %	Same as electrolysis	-
Solar PV	6 %	High end due to EH perceived risks	*Ref 35*
Wind Turbine	4 %	High end due to EH perceived risks	*Ref 35*
Ammonia Synthesis	8 %	Same as electrolysis	-
Average	**6.7 %**	-	-

4. Results

Section 4 aims to illustrate and analyse the findings of the present project. Results will be presented in paragraphs following the 3-step optimisation approach described in paragraph 2.3, and the logical transition between all of the results will be highlighted. In parallel, a cross examination of the results' validity will take place, by directly comparing the most up to date literature and forecasts with the current analysis' findings.

4.1. Step 1 – Definition of Off-taking Prices and Optimal Capacities

As already introduced, three investment alternatives are optimised and evaluated within the present analysis for utilisation of the electrolysis produced H_2. A MeOH synthesis plant, a compressed H_2 storage and an NH_3 synthesis plant. Following the methodologies and assumptions described in paragraphs 2.1, 2.2 and 2.3, the EH's opportunity costs of not participating in day-ahead trading in order to satisfy the desired production level of 48 GWh/y H_2 in the 3 different end-use scenarios are illustrated in **Figure *10***. The objective value expectation reflects all discounted annual cashflows (including annuitized CAPEXs) from the 4 studied representative years (2025, 2030, 2035, 2040) to the evaluation year (end of 2024).



Basis: WT - PV - Battery only, grid connected.

Figure 10. PtX specific opportunity costs

Ultimately, the rationale of the model revolves around maximising the expected value of total annuitised cashflows for the EH. This translates into optimising the total installed capacities for the combinations of each "case" (Electrolyser + MeOH synthesis, Electrolyser + Compressed H_2 storage, Electrolyser + NH_3 synthesis) in the least costly way. Ultimately everything breaks down to the trade-off between the volume of additional investment and the level of DA prices. Evaluation of the best sizing takes place and the final results, which are later combined according to Step 2 (paragraph 2.3.2), can be seen below in **Figure *11***.

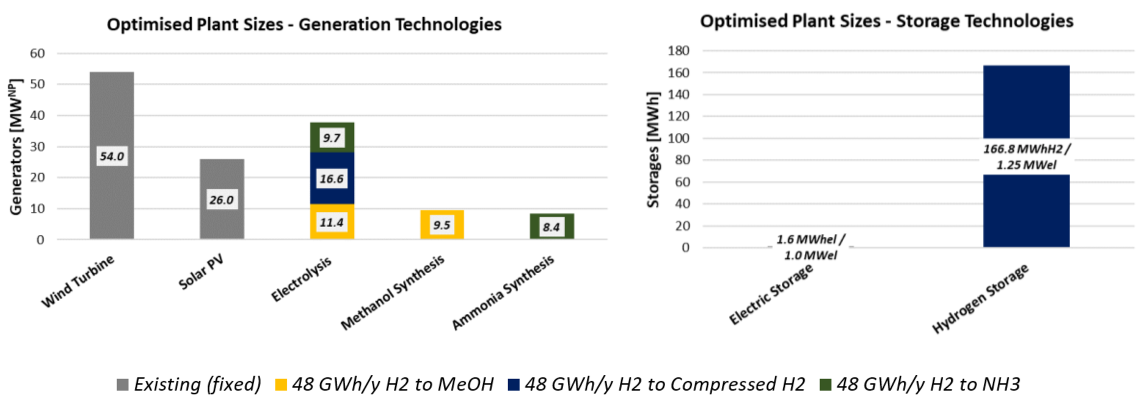


Figure 11. Optimised PtX capacities

In Layman's terms, what the model assesses is whether to invest in large capacities which will be operated for few hours in order to rapidly achieve the annual 48 GWh_{H2} targets and then focus on grid earnings, or to invest in smaller capacities while operating the plants for more hours. Thus, the main drivers are the shape and duration of day ahead prices across scenarios and years versus the size of investment and operational costs for each respective case's plants, once as described the revenues from PtX fuels at this stage are set to 0 $€_{21}$/MWh. This interaction can practically be seen for the case of coupling the electrolyser with an H_2 storage tank, where due to the low cost of the storing technology (**Table** ***10***), the model maxes out its limit of investment (limit of 5 tons of H_2 due to health and safety considerations) in order to cover those 48 GWh_{H2} quickly during the lowest grid price hours and then just turn to pure grid trading for the residual timesteps.

Having to balance out those opportunity costs for each assessed case (right side of **Figure** ***10***) via the sale of the total respective externally sold e-fuel quantities (**Table** ***5***: *Outflows*), ultimately sets the necessary level of off-take pricing for each output energy carrier in order to match the counterfactual grid earnings (balance price). Of course, with the heat price being fixed to a pre-defined general level (14.52 $€_{21}$/MWh), the final pricing level of the externally sold PtX fuels can be seen in **Figure** ***12***.

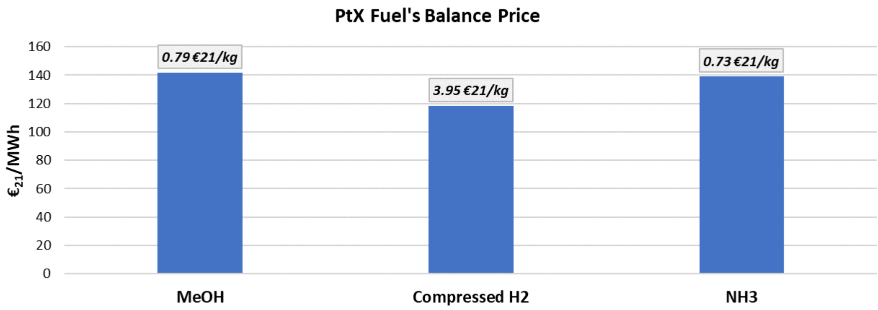


Figure 12. Off-take PtX fuel pricing

In an attempt to put everything into perspective with the up-to-date reality, the derived PtX fuel pricing from the present analysis is being compared to IRENA's outlooks for the production costs of green fuels: MeOH [Ref 30], H_2 [Ref 32] and NH_3 [Ref 31]. The main aspects defining the low and high ends for these fuels, according to IRENA's analyses, are mainly the H_2 costs for fuels depending on it as an input, while the CAPEX and electricity price for the electrolysis technologies producing H_2. The cost competitiveness of green PtX fuels, according to those references, is expected to considerably rise when moving closer to 2050, towards 0.25-0.63 €/kg_{MeOH}, 0.31-0.61 €/kg_{NH_3} and about 1.00 €/kg_{H_2}, due to improvements in all of the aforementioned elements in parallel to anticipated technological maturity (e.g. efficiency, durability).

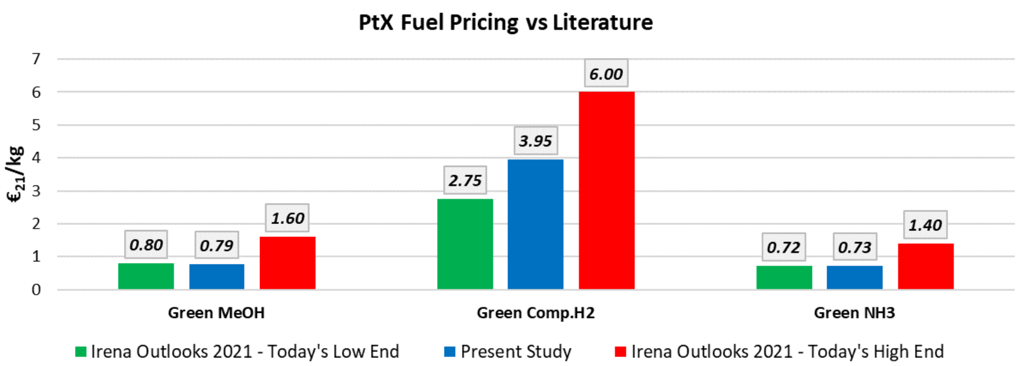


Figure 13. Validity of calculated PtX pricing

It should be kept in mind of course that the present analysis utilises price and cost forecasts of 2023&2024 technological maturities in 2021 price levels. Thus, it would be expected that IRENA's ranges would be slightly lower than the presented figures to match those technological forecasts, with the present study's fuel pricing farther away from the lower end of the spectrum. Nevertheless, the accuracy of the undertaken analysis seems to be encouragingly falling well between IRENA's ranges, thus those prices are being preserved and utilised with confidence in the upcoming Step 2.

Worth mentioning is the fact that during Step 1's definition of PtX fuel pricing, the generated fuel is entirely green once it just utilises internally produced electricity coming from WT and PV production at no cost, rather than purchasing from the grid and on top paying a grid tariff. However, when fed in Step 2, the model is anticipated to take advantage of this price and purchase also grid electricity when deemed profitable to do so in an attempt to benefit the total returns to the EH from increased returns via PtX product sales. A "Green-only" operation could have been studied, where no grid electricity would be purchased for PtX generation, however this would significantly impact each PtX plant's business case and would yield less interest from potential investors. It is considered that the part of grid electricity utilised for PtX production will be purchased under green agreements either via green-electricity bodies (e.g. Green Power Denmark [Ref 49]) or by direct PPAs with external RES generators. Further look into those aspects is out of the scope of the present analysis, however it is expected that only marginal changes in the results would be observed.

The final proposed EH set-up with capacities, prices and internal interactions is illustrated in **Figure *14***, with the grey box highlighting technologies consisting the EH.

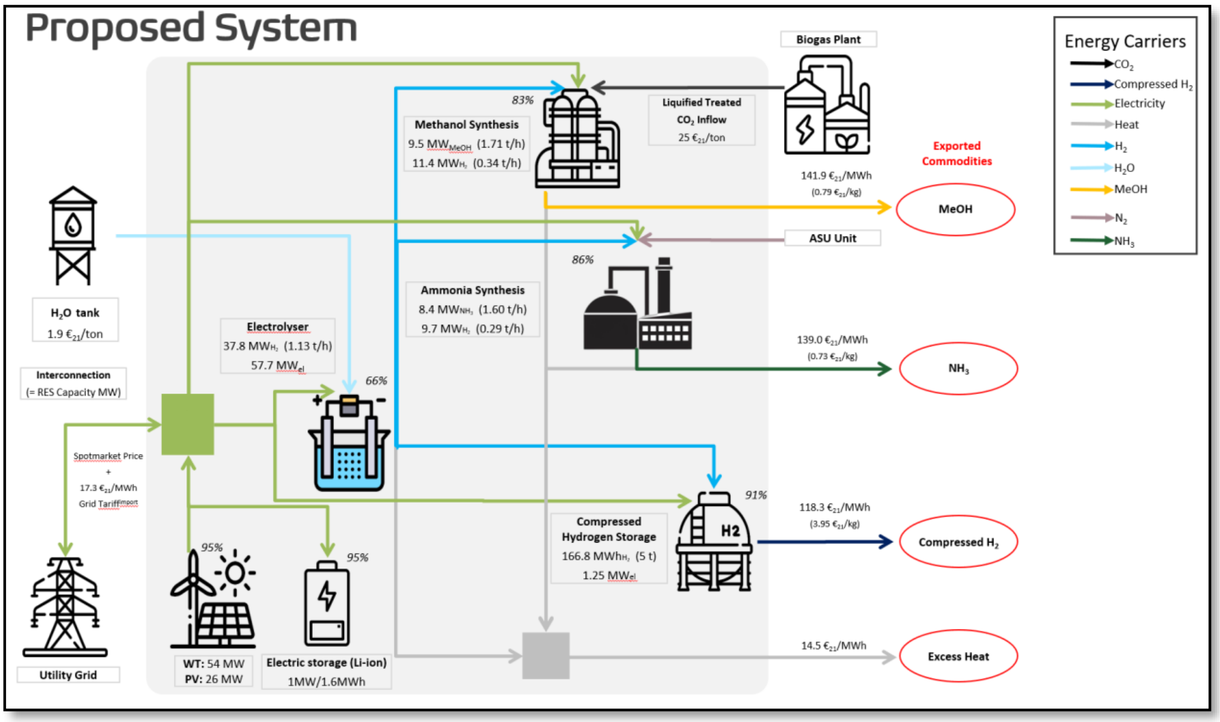


Figure 14. Optimised EH mapping

4.2. Step 2 – Optimised Dispatch Planning

Past optimising the capacities of the plants consisting the EH and also pinpointing a satisfactory but also competitive level of off-take pricing for the generated PtX fuels, the operational optimisation of the dispatch expectation across years and scenarios is taking place. Following the described methodology in paragraph 2.3.2 and of course the well detailed mathematical model in 2.5, **Figure 15** and **Figure 16** illustrate the cumulative operational results for each plant along the internal vs external trading levels for each commodity during the modelled representative years.

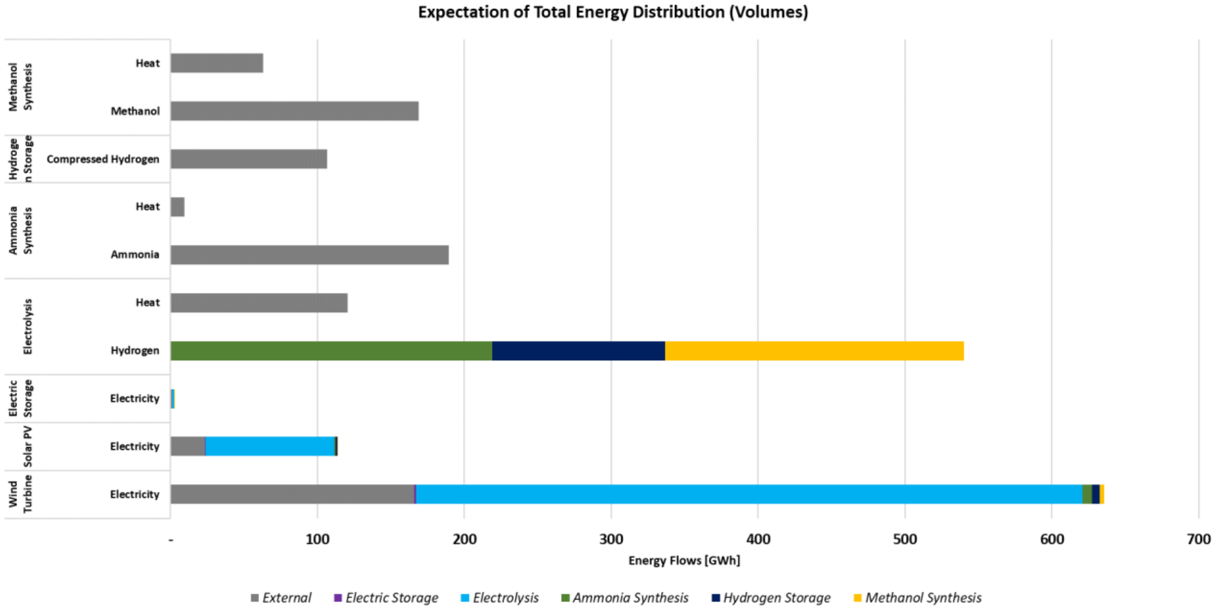


Figure 15. Expectation of energy carrier generation and distribution across representative years and scenarios

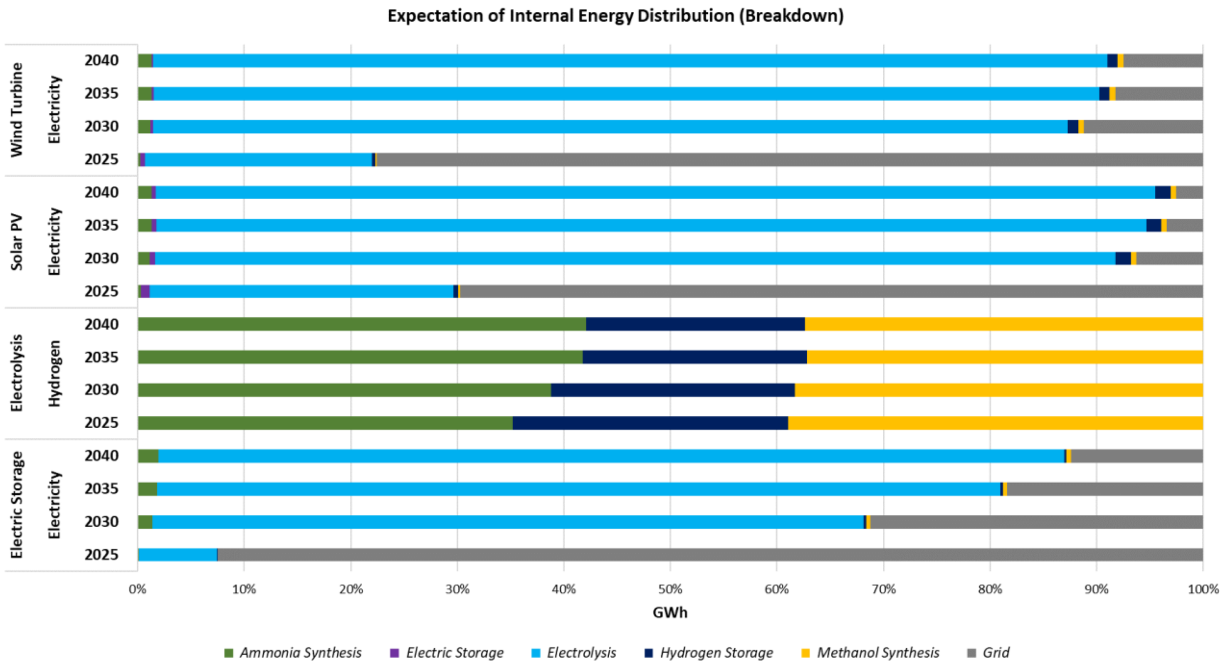


Figure 16. Expectation of internal vs external energy trading across representative years and scenarios

Regarding the internal distribution of RES electricity, it has to be mentioned that a proportional split is assumed during step 2, due to the pre-existing model's structure. In other words, as an example, when the electrolyser requires and purchases internal electricity, it follows a "fair" internal sourcing meaning that it proportionally purchases electricity from all RES units according to their generation potential at the given moment. If the WT produces 2x the electricity of PV, then the electrolyser will receive 2/3 from the WT and 1/3 from the PV. Any residual electricity will be sold to the grid or stored, or on the contrary, if profitable while accounting for tariffs, additional electricity will be bought from the grid. No pricing impacts occur due to the absence of internal pricing at the present step.

On the whole, some main patterns are being easily observed from the presented figures. Across years and scenarios, the main chunk of internally produced electricity (3/4) is directed to the electrolyser, something expected via the relationships shown in **Table *5***. Additionally, the NH_3 synthesis plant proves to marginally be the most profitable option for the EH against the MeOH synthesis plant. Regulation abilities mentioned in **Table *9*** have a direct impact on such decisions and the level of each plant's operation, with the less flexible NH_3 plant having to be operated in higher frequencies in order to reap its capacity benefits, possibly even in hours where it wouldn't ideally have to operate on a high level, (sudden high DA price hours) due to its lower regulation abilities. An in parallel competitive investment optimisation procedure could shed more light on such elements, however it is not within the scope of the present work.

In a more detailed annual resolution, the impact of the DA pricing expectation is evident, with 2025's operation being heavily driven by the grid's high price signals, something overturned while moving to farther away years when prices keep falling. The expectation of high prices in 2025 also enables a relatively higher battery operation for arbitrage, in contrast to later years. During years with low grid prices, the model is able to almost entirely utilise any internally generated electricity and have a higher return from e-fuel sales than with the battery's arbitrage. **Figure *17*** clearly defines that for less than 100h/y internal electricity production surpasses the peak internal demand from all units, when the EH would have to find an alternative to its electricity use or curtail it (in case of negative grid prices). For such reasons, it will be seen that the pre-existing assumption of a battery's presence coupled to the WT is not beneficial under the examined circumstances and its FLH diminish significantly towards 2040, from the already low levels of 2025.

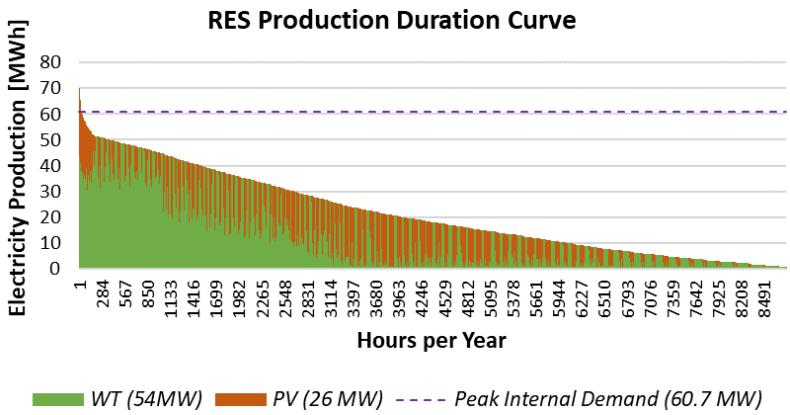


Figure 17. Internal electricity generation vs total consumption potential

The expectation of the dropping electricity price levels as well as low-price level duration across years becomes also evident from the model's choice to import increasing amounts of electricity as the years go by (**Figure *18***) in order to increase the EH's revenues in relation to what it would achieve from pure grid trading. Contribution on this effect inevitably has the decision to not optimise for RES generator capacities but only for PtX assets in order to examine their competitive nature in such setups. **Figure *17*** makes evident that the internal electricity production is significantly lower than the peak internal demand in the vast majority of the year, a fact that considerably drives the final electricity sourcing percentages shown in **Figure *18***. Additional drive for this type of operation also brings the regulation abilities of the PtX plants due to their minimum load necessities but also hour-to-hour ramping rate capabilities. Making the most out of such units would require electricity imports when the internal RES production is low in order to preserve long high-capacity PtX operation, as long as the resulting operational benefits overweigh the costs of the combined grid pricing and import tariff. On the whole, it is expected that 2/3^{rds} of the PtX fuels will be able to be green by electricity produced within the EH's borders, while the rest will have to be sourced from green electricity providers or with other third PPA contracts at prices close or lower to the long-term anticipated expectation of DA capture price by the EH across scenarios. Future look into limited RES investments could also lead to some improvements.

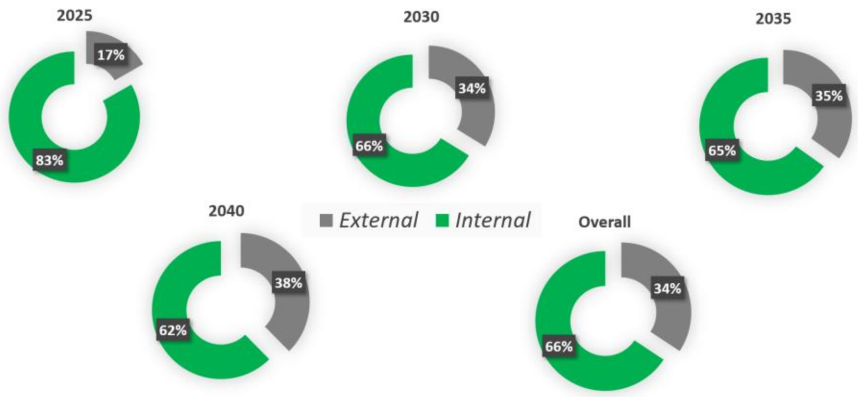


Figure 18. EH's electricity sourcing

Analysing the dispatch results from each technology, a deeper look on the EH's operation surfaces. Firstly, indeed the expectation of a low battery utilisation proves to be real according to the drop of the experienced FLH from 948 to just above 500 in 2040. In parallel, the preference of the model towards the more profitable PtX plant is evident, with the NH_3 synthesis plant having the edge, with its regulation ability expected to be impacting those results. On the other hand, the more flexible MeOH synthesis plant is pretty muh following the regulating behaviour of the electrolyser, as expected according to DEA [Ref *23*], and thus reflects some lower FLH. Lastly, the compressed hydrogen storage seems to be getting the remainder from the H_2 production, due to also the assumed inflexibility presented by its operation as a grid-connected storage with either charging or discharging operation in any given moment. Finally, encouragingly, the expectation of the electrolyser's operation from 2030 and on seems to be revolving slightly below 5,000 FLH and thus below the approximation of 90,000 - 100,000 FLH within the length of the project's horizon of 20 years [Ref *23*], avoiding considerations over any extra necessary capital expenditure for stack replacement after the passage of those FLH, rising to almost 30% of the initial investment.

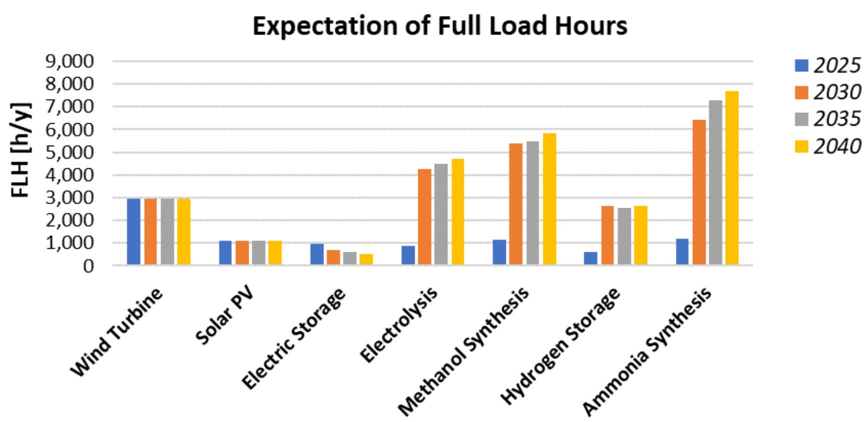


Figure 19. Unit specific FLHs per milestone year

4.3. Step 3 – Internal Pricing Definition and Profit Distribution

Having defined an optimised dispatch planning for each scenario realisation, and due to all external transaction pricing being set from both exogenously defined data but also optimisation undertaken during Step 1 (paragraph 4.1), the pre-tax expectation of the EH's objective value for the representative years can be calculated. The absence of internal pricing until this point does not affect this figure due to the collaborative nature of the EH making this internal pricing just a factor towards revenue distribution final profit/taxation calculations amongst investors, while also highlighting any necessities for actor compensation in order to achieve their break-even point. For example, in cases of continuous high grid prices, the price of the internally produced H_2 will have to be considerably high in order for the electrolyser to recover its costs, thus hindering the PtX fuel units to recover their own costs purely through the pre-optimised external pricing (fixed). In such cases, those units would have to receive a compensation per produced output unit on top of their predefined off-take price in order to achieve a break even in expectation (see Equation 54). The determination of the liable supply-chain party for the payment of such compensations, or the existence of any fund-supported EH allowance preventing such cases, has been ruled out of the scope of the present analysis, however solid conclusions acting as future drivers can be derived.

On the whole, the expected value of the total EH's profits for the 4 representative years can be seen in **Figure** *20*. The total Earnings Before Tax (EBT) for the EH as a whole rise to 13.1 mil.€$_{24}$, a value encouraging on the first looks, which will be further evaluated however for each investor during the upcoming parts of section 4.3, after including taxes but also interpolating the results for the whole lifetime of the project in order to obtain a more complete picture.

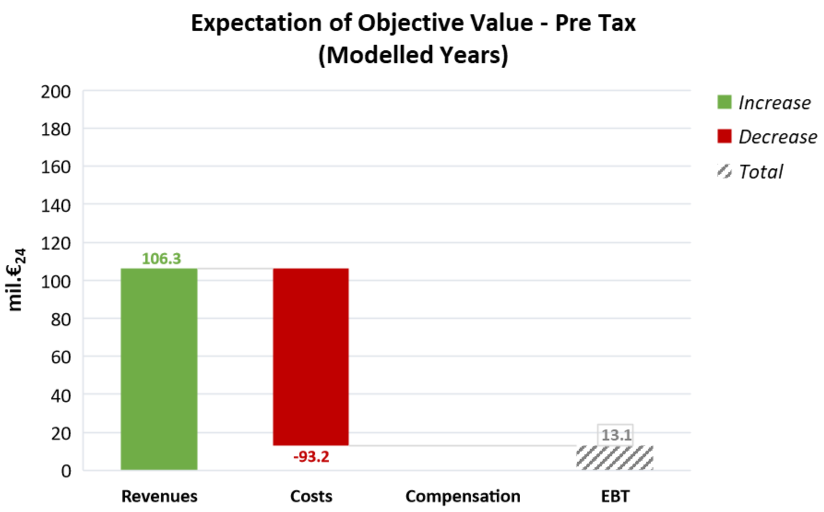


Figure 20. Expected value of EH profits across the 4 representative years

Having calculated the expectation of the overall EH returns, the distribution of those cashflows across investors will require the definition of an acceptable by all actors level of internal pricing between units, while simultaneously respecting all of the requested investor specific requirements. It has to be stressed that even though the present section approaches the internal contracts in a b2b setting, it doesn't reflect a PPA scheme due to the absence of any agreed level of minimum annual energy delivery. An in-depth analysis of the conditions revolving such contracts is out of the scope of the present analysis, however the generated results can shed light on satisfactory for all parties pricing levels, which could potentially later on act as a steppingstone for bilateral negotiations bringing actors closer to reasonable talks and successful agreements. A brief check on the impacts of PPA clauses can be seen in paragraph 4.6.3.

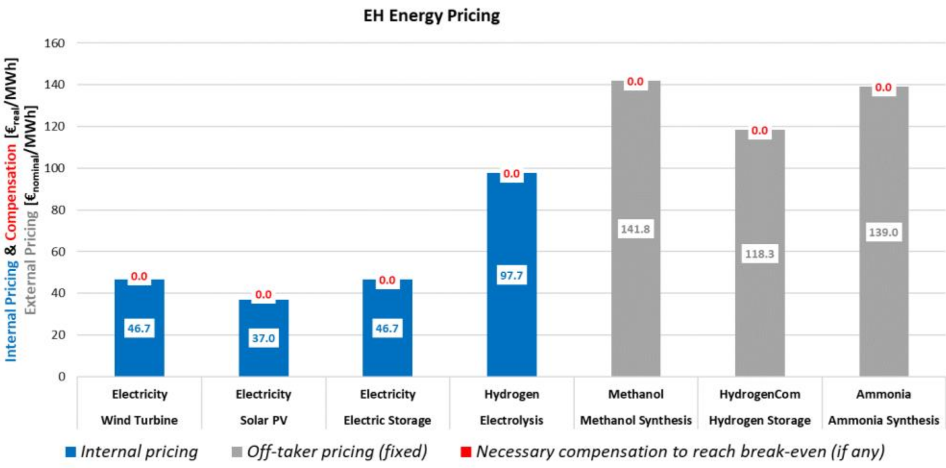
After the disturbances of the “usual” DA market prices and tendencies deriving from the COVID-19 recovery period, PPA agreement formation has been challenged due to the high attractiveness of sole grid trading based on the continuous rise of the observed spot-market prices. Nevertheless, bearing in mind the global, European but also Danish green transition targets, it is not expected that these high DA prices are going to persist for many years, especially in the context of a 20-year horizon, with further constitutional push towards PtX development expected if such prices persevere. Ultimately, a ruler has to be designed for the definition of a good level of internal electricity pricing under EH formations. With 2025 prices acting as an outlier to the long-term forecasts, and with years from 2030 and beyond bearing the same level of price convergence across the utilised scenarios, the current analysis will utilise statistics from 2030 and on, in an attempt to define a good range of electricity pricing level for internal trading, aiding the formation of long-term beneficial contracts.

By utilising the 2 most contradicting scenarios from 2030 beyond, “PreUkraine” for low prices with the longest duration and “HighGas” for high prices with the longest duration, an acceptable price range for each RES generator (WT and PV) can be pinpointed at, based on the average nominal capture price that those plants would experience in sole interaction with the grid (absence of any EH setup). This range rises to 46.7-48.2 €/MWh for the WTs and 37.0-41.2 €/MWh for the PVs, in between which the model will be allowed to define the final optimal internal electricity pricing, stable across the EH’s lifetime. It should be also mentioned that the battery is assumed to be part of the WT plant, thus will follow the WT pricing.

The validity of those price ranges can be cross examined with up-to-date sources around the world. For Denmark, as of 2022, the forecasts for newly built WT and PV plants rise up to marginally lower than 40 $€_{nom}$/MWh in b2b trading groups [Ref *36*], while the range from the latest publicly available data in the US, reported in 2021, ranged from approximately 15 $€_{21}$/MWh in SPP region, up to 39 $€_{21}$/MWh in CAISO region [Ref *37*] with clear indicated dependencies in the gas market price, around which the PPA prices revolve. Of course it should be kept in mind that the status quo of the PPA pricing in Europe has been challenged in 2022 due to the ongoing energy crisis, with the P_{25} index of PPAs (lowest 25% of wind and solar PPA agreements) jumping to 47.97 $€_{21}$/MWh for PVs and 56.96 $€_{21}$/MWh for WTs at the end of 2021, a 7.2% and 8.2% respective hike from the previous quarter [Ref *38*]. However, with 2024 being the evaluation year for the project, all of the aforementioned sources lie well closely around the expected average RES capture price ranges. Further look on the implications of fluctuations in those ranges will be examined in the corresponding sensitivity analysis section, paragraph 4.6.2.

Running the model for a last time with the aforementioned allowed price ranges in regard to internal electricity trading, results in the final level of optimal pricing seen in **Figure *21***. Before moving forward, it should be mentioned that Wind Turbine & Solar PV & Electric Storage but also Electrolysis & Hydrogen Storage are assessed as a whole in respect to their break-even clause, thus no compensation requirements emerge, as will be further discussed in the next paragraphs.

Before proceeding, it should be noted that usual feasibility analyses and NPV breakdowns assume the whole investment payment taking place before the COD, and then just annually reflect on each years cash balances, while accounting for the time value of money and any discounting across the project’s lifetime. The present analysis, however, utilises a different way of evaluating the operation of each plant, which ultimately returns the



**Nominal: value indicated at €21 level, subject to inflation in the respective years. Real: unchanged across all years.*

Figure 21. Definition of satisfactory levels of internal pricing

exact same results as the aforementioned "usual" analyses. However, the benefit of the utilised methodology is that it also evaluates the annual effectiveness of each year's operation towards the initial investment's capital recovery. In other words, while evaluating the cashflow as a whole, the analysis also aims to distribute the initial investment in an equal series of "payments" across the years and assess the rate that each plant is recovering its costs across those years, while also accounting for the time value of money. The annuitisation of the CAPEX in equal 20-year increments in the present study takes place via the use of Capital Recovery Factor (CRF). Of course, the present value of all annual "investment segments" (discounted to the evaluation year) sums up to the same amount of investment that a "usual cashflow" would showcase before the COD. So, it is practically just a matter of analytical perspective, with the followed just aiding the derivation of more detailed year to year statistics, like LCOE, something which will be further discussed on following paragraphs. For instance, taking the total installed investment cost for the electrolyser by combining the economic data from **Table *10*** (Electrolysis: 0.56 €$_{21}$/MW), the construction duration from **Table *9*** in order to calculate the investment year and consequently price level as COD-Construction Duration (2025-1 = 2024) and finally the optimised total installed capacity from **Figure *11*** (37.77 MW), results in:

Inflation Rate	2%
WACC	6.71% Nominal Pre-tax
Construction Duration	1 y
COD	2025
Investment & Valuation Year	2024
Horizon	20 y
CRF	0.09
Capacity	37.77 MW
CAPEX	0.56 mil.€21/MW

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Upfront Investmet [mil.€24]	22.29	*1st way*																			
Annuitised Investment (FV) [mil.€]		2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06	2.06
Discount Factor	1.00	0.94	0.88	0.82	0.77	0.72	0.68	0.63	0.59	0.56	0.52	0.49	0.46	0.43	0.40	0.38	0.35	0.33	0.31	0.29	0.27
Annuitised Investment (PV) [mil.€]		1.93	1.81	1.69	1.59	1.49	1.39	1.31	1.22	1.15	1.07	1.01	0.94	0.88	0.83	0.78	0.73	0.68	0.64	0.60	0.56
NPV [mil.€24]	22.29	*2nd way*																			

Figure 22. CAPEX Annuitisation

Having derived all pricing relationships enables the calculation of the expectation of after-tax profits for all participating plants within the EH. **Figure *23*** illustrates the present value (PV) of all future annual cashflows for all modelled years. On a first quick glance, the left side of the figure may be misleading, so it is important to stress that each year's cashflows also include the corresponding annuitized CAPEX amount, in the manner showcased and explained in **Figure 22**. Thus years with negative cashflows practically mean that the annual revenues cannot surpass the equivalent segment of the CAPEX plus all residual annual costs. The right side of **Figure 23** can shed more light on only pure annual cashflows.

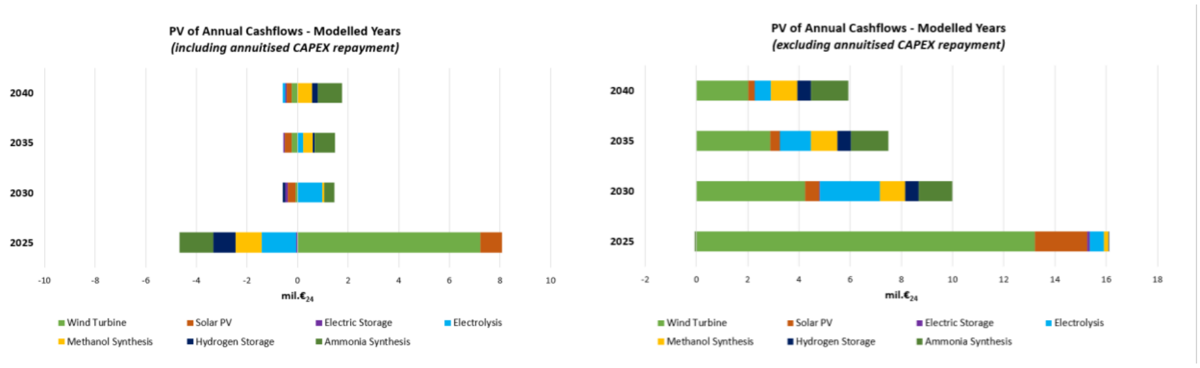


Figure 23. Expectation of corresponding annual cashflows (PV)

When assessing the results on an annual basis across the 4 representative modelled years, it becomes apparent that RES generators make the biggest part of their returns during the early years of operation, when the expectation of DA prices reflects long duration of high prices. Practically this enables such investors from the one side to take advantage of the time value of money and recover their investment rather early on, allowing them to potentially re-invest sooner in new assets. On the contrary, PtX fuel plants as expected, seem to be gradually gaining increasing returns with the passage of the years, the more grid prices follow a longer downward trend and the effects of commodity inflation compound. Focusing on the electrolyser, the importance of time value of money is getting stressed, where due to the assumed constant across years nature of any internal trading transaction (not subject to inflation), the impact of cashflow discounting becomes extremely evident by following a reverse tendency with the residual PtX assets, even though the expectation of FLH for PtX assets rises from year to year, as presented in **Figure 19**.

Undeniably, taking decisions, especially for elements like commodity pricing, would have to be as informed as possibly can. For this reason, the optimised pricing decisions which will satisfy the financial clauses of all investors are ultimately based on all operational years of the EH (20). The showcased NPVs for each asset (**Figure 23**) are getting extended across the lifetime of the project via interpolation of the modelled results for years between the closest modelled ones. Based on those, **Figure 24** illustrates in detail the elements shaping the final after-tax lifetime NPV for the EH as a whole, by summarising all investor specific cashflows.

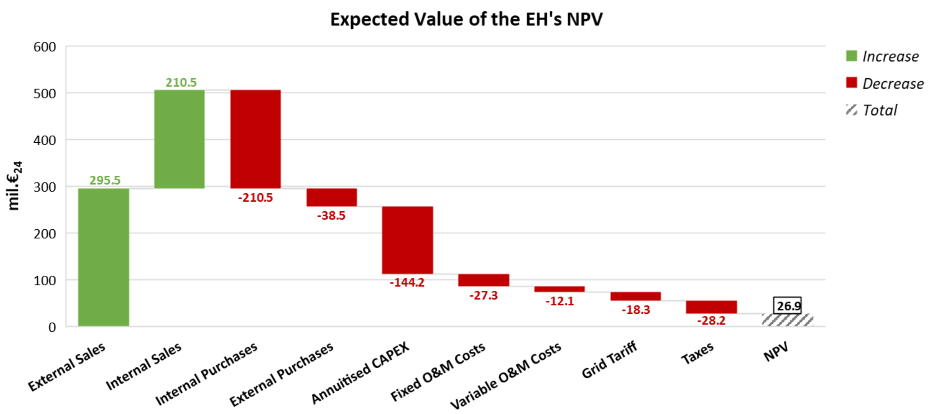


Figure 24. Breakdown of the total EH NPV across its lifetime

Evidently, **Figure *24*** presents 2 aspects in relation to the final produced results. Having already accounted for the uncertainty over revenues from all external sales pricing (Step 1 – paragraph 4.1), it becomes apparent that the total assumed installed unit costs [$€_{21}/MW^{NP}$] highly affect the feasibility potential of each plant and subsequently the EH as a whole, while the level of internal pricing directly shapes the change of profit distribution between actors. A more extensive look into the impacts of the fluctuation of those aspects on the model's robustness and any occurring observed changes will be showcased via sensitivity analyses undertaken in paragraph 4.6. A more detailed look into the breakdown of the total EH profits across investors can be seen in **Figure *25***.

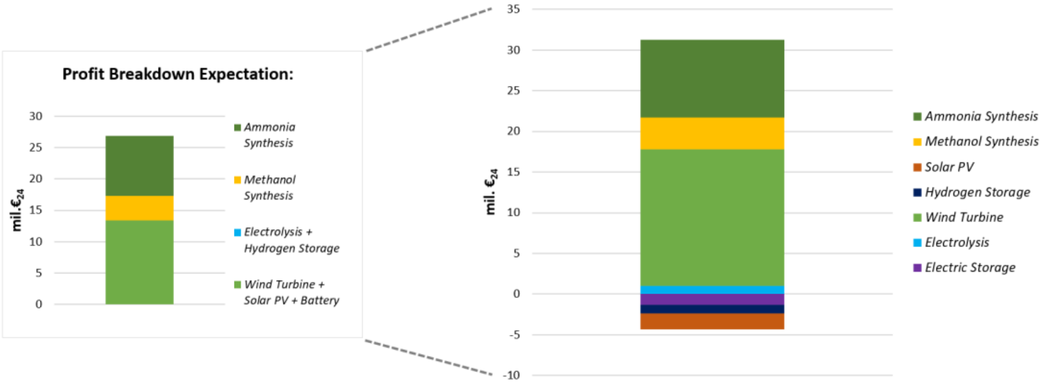


Figure 25. Expectation of profit distribution

Expectedly, a reader's attention would fall on the assets not hitting their break-even point, and more especially on RES generators like Solar PV. By taking those assets as pre-defined fixed values (not subject to optimisation - see paragraph 2.1) and assessing them by the utilised solar profiles (**Figure 9**), such a result could be expected. In an attempt to place everything into perspective, **Figure *26*** compares sole operation of the RES generators on a grid connection basis only across scenarios versus the corresponding Grid and EH connected setup. There, a series of observations can be made, with the primary being that the NPV not only wouldn't had hit break-even on a grid only operation either, but also would have enjoyed a better overall return in the majority of scenario realisations (similarly for WT). Further insights into the value of participation in an EH for RES generators will be explored in the following paragraph (4.4). For this reason, all exogenously defined technology capacities have been bundled in **Figure *25*** but also within the break-even clause present in the model, assumed to be investments from the same investor, with the high WT revenues expected to cover their break-even requirements.

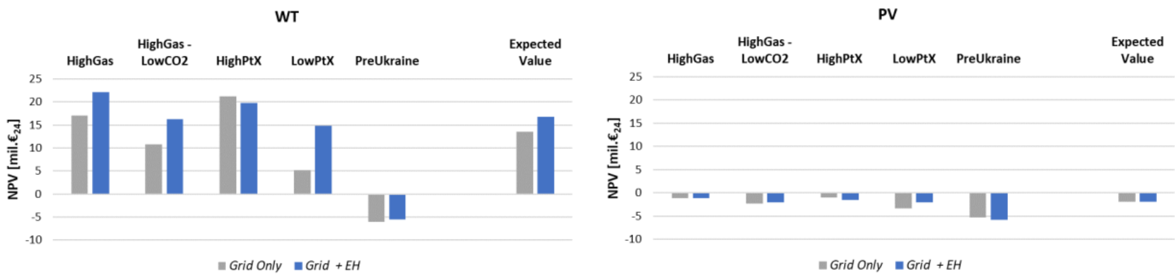


Figure 26. Grid vs Grid + EH RES operation

Regarding the hydrogen storage, on the other hand, it is apparent via **Figure *17*** that the EH specific electricity generation is rarely enough to feed all internal peak PtX demands, which showcases that such a storage under no specific external demand targets or any strategic trading behaviour on a liberal market, is the least favoured technology under such conditions. Remember that one of the main aims of the present study has been the research of the competitive nature of such assets within an EH, thus no expansion of RES generators has been allowed intentionally. Practically, Step 1 (paragraph 4.1) showcased the best offer that an individual investor could offer to balance the opportunity cost of RES generators by joining an EH, while Steps 2 (paragraph 4.2) set those PtX assets in competition for the non-abundant RES electricity. Nevertheless, due to the discussed plans for a rapid Hydrogen Economy within Europe, such storages may be of key importance for electrolysers, thus will be also bundled under the same investor's cashflow in the following analysis.

The number of years required for each individual asset to reach its own break-even point can be seen in **Figure** *27*, with 2024 signalising the total size of investment before COD.

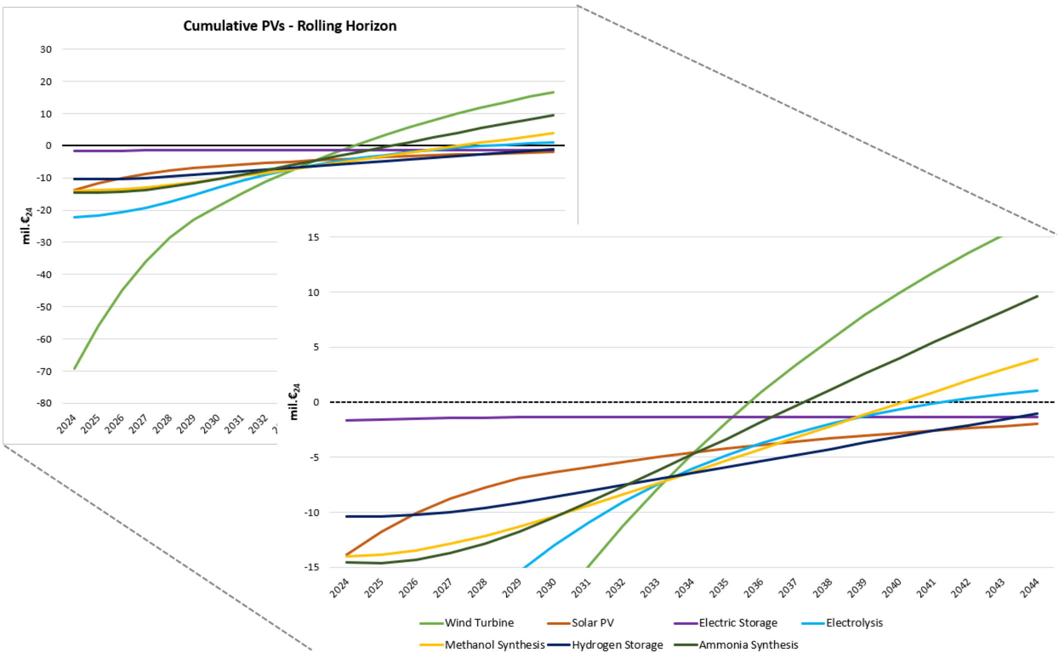


Figure 27. Years to break-even

Attempting to place all analysed assets on the same page and evaluate them against each other, the internal rate of return (IRR) for each plant is being calculated. IRRs higher than the utilised WACC of 6.71% (**Table** *12*) signalise profitable projects on their own, while the comparison between individual IRRs shed light on the most value-for-money investment.

Table 13. Plant specific IRRs

Nominal $WACC^{pre\text{-}tax}$	Wind Turbines	Solar PVs	Electrolysis	MeOH Synthesis	H_2 Storage	NH_3 Synthesis
6.7%	10.4%	4.2%	7.3%	9.1%	5.8%	11.5%

While **Figure** *25* and **Figure** *26* discuss the expected value of the lifetime experienced NPVs across scenarios, the realisation of each assumed scenario would not only result in different level of returns, but also on a considerably different profit distribution across assets. **Figure** *28* makes apparent that the overall profits can range upon realisation from 11.75 to 33.04 mil.€$_{24}$, with the lowest overall profits reflecting low returns from DA participation for the RES generators but the highest absolute returns for PtX assets, as it was to be expected. Scenarios such as the HighPtX, reflect the most relatively flat price curve across scenarios (**Figure** *8*), thus even though the overall returns are relatively lower due to less hours of high

DA prices, the flat curve is still considerably more profitable for the EH against the PtX path, and for this reason the WT investor enjoys the highest relative returns.

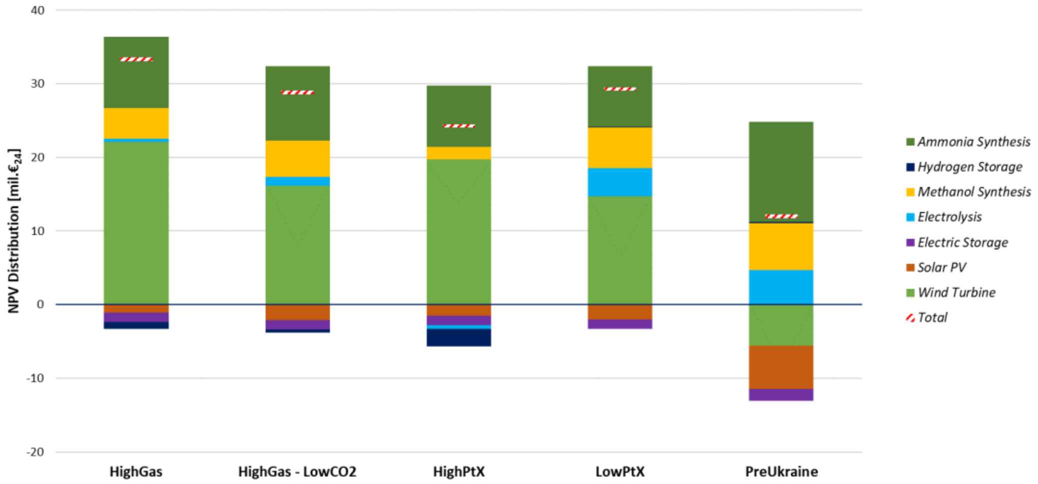


Figure 28. Scenario specific profit distribution

Last but not least, the Levelised Cost of Energy ($LCOE^{NP}$) expectation for all operating non-storage assets is presented in **Figure** *29*. The slight increase of LCOEs for assets with predefined deterministic generation profiles such as the RES generators, is the effect of inflation on their O&M costs. On the whole, WT generators seem to be on slightly above the weighted average literature values for Europe in 2021 (present study's average: 48.8 €/MWh, IRENA: 42 €/MWh [Ref *55*]), meaning the expected difference could be higher versus the 2025 realised figures, depending on the relation of true CAPEXs and inflation. PVs reflect a higher distance on expectation to literature values (present study's average: 57.1 €/MWh, IRENA: 48 €/MWh [Ref *55*]). Of course, the impacts from the economy of scale effects is always something to keep in mind when comparing and drawing conclusions between such figures. Further, it seems like WTs would be just below their break-even point via pure EH participation if all of its generated electricity would be consumed at any given point, when comparing the average LCOE with the internal pricing showcased in **Figure** *21*. On the other hand, this is far from reality for solar PVs. On the PtX asset front, the low operation of them in the first years of their lifetime due to high grid prices is being reflected in the LCOE spike, which later subsides when their annual operation picks up. No direct comparison of LCOE vs off-take pricing can take place for the MeOH and NH_3 synthesis plants due to the former being subject to its year's inflation. However, for the Electrolysis plant, the average $LCOE^{NP}$ across the modelled years rises to 93.24 €/MWh, slightly lower that the optimised internal pricing point, a fact that allows the electrolyser to surpass on expectation its break-even point (right part of **Figure** *25*).

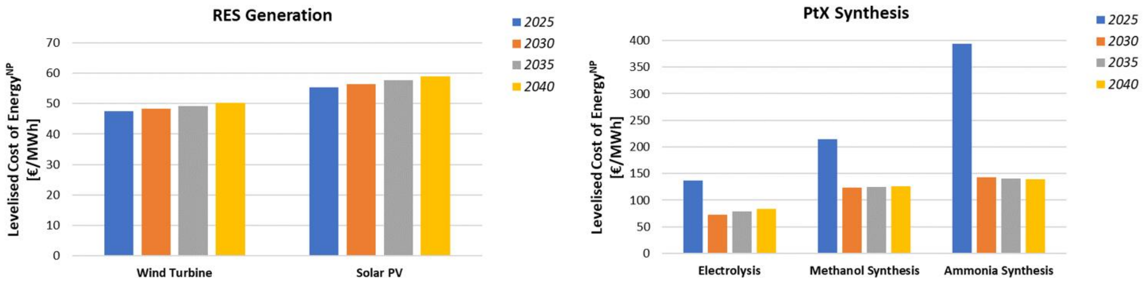


Figure 29. Expectation of LCOEs

4.4. Value of Participation in an Energy Hub for RES generators

After all of the aforementioned results, the value of participating in an EH for any actor becomes more and more self-evident. However, due to the challenge of such agreements since the beginning of the latest energy crisis, a short paragraph will be presented to showcase the derived benefits of such formations. While the advantage of having RES generators present in an EH is obvious from a PtX related side both obtaining higher proportions of locally produced green PtX fuels, but also avoiding the burden of any grid tariffs in cases of grid imported electricity, the same doesn't apply for the RES generators themselves. It seems like the attractiveness of participating purely in grid trading has significantly impacted recently signed PPAs in Europe by slowing down their formation, possibly due to the expected RES side opportunity cost that is coming in play by the minimum necessities of delivered electricity volumes to the receiving end [Ref 38].

The duration of the period with high prices will prove itself with the passage of time, however the green transition cannot be put on hold. By taking a deeper look into the formed DA scenarios and utilising the one with the highest price levels and duration (HighGas), important insights can be shaped for RES generators. Of course, the present analysis doesn't deep dive into bilateral PPA agreements by incorporating minimum requirements of annually delivered volumes, however it can still showcase the optimal potential area of benefits for RES generators based on the agreed long term price contracts, with the result being subject to agreed flexibilities. **Figure 30** illustrates the power of participation in an EH for a WT generator, with a similar situation expected for a solar PV plant. Even in the scenario of the highest prices, because the optimisation model aims to maximise the total EH returns (minimise its experienced costs), it can be seen that in 2025 the model is still following the grid signals and the EH participation provides minimal additional benefits to WT generators (0.3%). However, those high price signals are not expected to last long, and just in 2030 while still observing the realisation of the same scenario, the EH attributed benefit from the optimal internal pricing shown in **Figure 21** rises to an additional 11.7% of revenue (0.76 mil.$€_{nom}$) for a WT plant, due to higher revenues for the EH coming from the PtX stream as a whole rather than DA participation, allowing RES producers to internally sell their electricity in more favourable terms than the spot-market [see **Figure 21**]. The occasional drop of the blue lines below the internal price point (flat blue line) are occasions where the DA price suddenly reduced for a short amount of time and jumped up again, thus the flexibility of the PtX assets in parallel to their regulation properties were not worth their ramping.

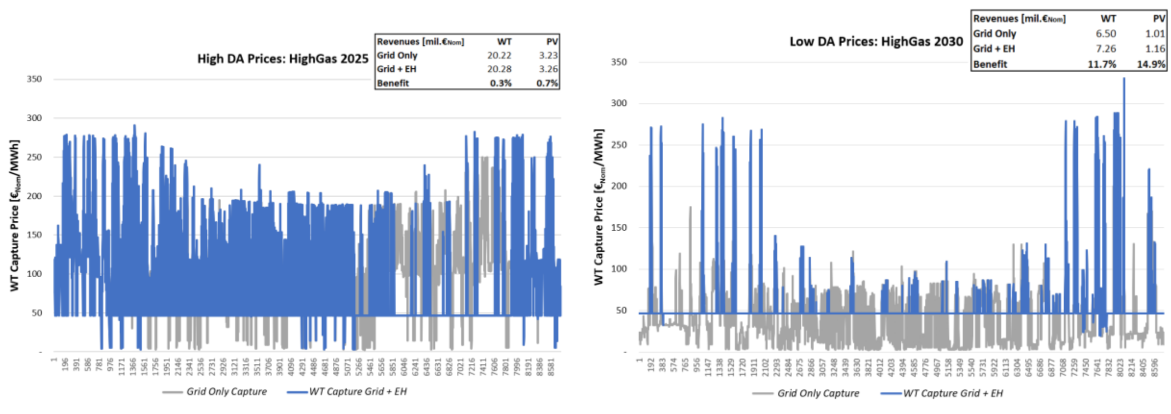


Figure 30. RES capture prices: Grid vs Grid + EH

Such participation in an EH proves thus to be a win-win situation on the long run for all parties in the present setup. Aside of the previously mentioned PtX investor benefits, it can also provide grounds for a more robust business case for RES generators due to the experience of less fluctuating revenues. For instance, in the HighGas scenario and for the modelled years beyond 2030, pure participation in DA trading would result in an average capture price for the WT asset of 48.2 €/MWh, whereas a Grid+EH participation at a long-term internal price of 46.7 €/MWh results in an average capture price of 55.8 €/MWh. A caveat to be stressed, of course, has to be that this is an optimal value derived by no volume-wise commitments and a co-optimisation with the EH in the centre of the benefit. However, in real long term PPA style contracts, the benefit is expected to be lower or negative in case of low energy delivery commitments during prolonged years of low DA prices. Nevertheless, it is self-evident that with a maximum achievable delivery flexibility across years, and with a collaborative operation of the EH as well as other potential measures such as a level of revenue sharing/redistribution according to specified conditions, could bring the showcased benefit close enough to the optimal levels. Such analysis has not been part of the present study due to time limitations, however consists a vital field of future work.

4.5. Value of Stochastic Optimisation

With the present model including both Here-and-Now variables (decisions that have to get made before the realisation of the uncertainty: Investment optimisation) but also Wait-and-See variables (decisions that can be made after the realisation of the uncertainty in order to derive the best possible outcome: Operational optimisation), the model classifies as a recourse program, or in plain terms as a two-stage stochastic programming.

Solving each uncertain scenario individually before taking a final decision, results in multiple solutions and thus a big pool of options, with each option being favourable towards only 1 scenario. Having 5 scenarios, the reaction of the optimal stochastic Here-and-Now decisions across scenarios would result in just 5 values. On the contrary, deterministic Here-and-Now decisions resulting from each scenario would rise to 5 times the number of values, both from a decision variable perspective but also from a result realisation across scenarios. It is apparent, thus, that with an increasing number of scenarios this option pool gets vastly bigger and more difficult to assess on the whole before pinpointing the best decisions that have to be taken moving forward. Of course, stochastic models, especially with integer variables as the present one, require significantly higher computational power to get solved when compared to the solution of the deterministic equivalents, but in the end the results and any further analysis prove to be more solid across scenarios, avoiding mainly the realisation of extreme situations.

As an example, the optimal investment decisions in electrolysis capacities regarding the 2 more profitable plants (MeOH and NH_3) which were presented in paragraph 4.1, will be compared to investment decisions that would have been taken if assuming a deterministic scenario each time, for the two more opposite DA pricing scenarios in **Table *14***.

Table 14. Stochastic vs Deterministic optimisation: Electrolysis investments [MW_{H_2}]

Scenario	MeOH-Only	NH_3-Only	Total
PreUkraine (Low DA Prices)	10.1	7.4	**17.5**
HighGas (High DA Prices)	11.6	9.8	**21.4**
Stochastic	11.4	9.7	**21.1**

It can be seen that the optimal stochastic solution lies between the deterministic optimal equivalents, while taking into account the probabilistic weighting of the scenarios in order to define the best final decision. Calculating the investments for the Compressed H2 Only case (which has not taken place due to the computational burden that comes with the presence of binary state variables reflecting the charging or discharging activity of the storage and the low levels of available time within the Thesis span) and feeding them into a new dispatch run (Step 2) for each deterministic scenario, would make obvious that the optimal solution of the stochastic model would similarly lie between them. However, upon realisation of scenarios, the final EH returns resulting from deterministic runs would have been significantly more volatile across scenarios.

As a bottom line, the value of stochastic optimisation lies on sacrificing some best case returns in order to secure less bad results in case that the "worst case" scenarios come to realisation. Stochastic vs deterministic solution evaluation means exist in the literature, with EVPI (maximal amount planner would be willing to pay to get a priori information) and VSS (benefit from using stochastic programming compared to using expected values) being some of the most prevalent [Ref *50*]. However, further investigation of such topic has been ruled out of the scope of the present analysis.

On the whole, perfect information is rare in the real world. A series of uncertainties impose significant impacts on any business case, thus approaches like the presented can result in less fluctuating results for any investor, and a more solid business case analysis.

4.6. Sensitivity Analyses

In an attempt to showcase the robustness of the presented model across fluctuations of the most decisive aspects incorporated in the present analysis, a series of model testing setups will be illustrated. Following the EH's NPV breakdown shown in **Figure *24***, it becomes apparent that the overall profitability of the EH is being decided upon the trade-off between participation in DA electricity trading vs PtX fuel sale. Having a cost driven model, highly depends on the specifications of the imported alternatives. For this reason, the sensitivity of the necessary balance price and consequently the competitive potential of the produced PtX products will be examined in paragraph 4.6.1. Paragraph 4.6.2 will explore the impacts that the allowances over internal electricity pricing levels would have on the experienced NPV of each asset. Finally, paragraph 4.6.3 will touch upon the tendencies of changes on profit distribution across the EH members when bilateral obligations are set in place.

4.6.1. Off-take Pricing Sensitivity vs DA Prices & CAPEXs

It is no secret, especially after the latest electricity market tendencies in Europe, that grid prices are directly linked with natural gas prices [Ref *51*]. In parallel, prices of commodities such as ammonia are also following those signals, rising 6-folds since 2020 [Ref *52*]. Subsequently, due to the present analysis trying to evaluate the best PtX fuel pricing which would balance the EH's opportunity costs from lower spot-market trading while covering all additional investment and operational costs, makes the competitiveness of the produced commodities to be of high importance for the attraction of investors. For this reason, an exploration of a combination of electricity price and CAPEX level circumstances will be brought to the forefront, and their impacts on the pricing will be evaluated. **Figure *31*** illustrates the matrix of the examined possible cases incorporating those 2 monetary elements, and the relative changes they result in when comparing to the modelled entities. Due to time limitations of the current project's span, the sensitivities will only run for PtX generation technologies and not for storing (hydrogen storage), where the optimisation run demands a considerably higher completion time due to the presence of binary state variables. Nevertheless, the same patters would be expected. Briefly:

I. Low CAPEX (LC): Low end of total installed cost forecasts for PtX technologies across the literature [Ref *23*, Ref *30*, Ref *53*, Ref *54*]
II. High CAPEX (LC): High total installed cost forecasts for PtX technologies across the literature [Ref *23*, Ref *30*, Ref *53*, Ref *54*]
III. Low Price (LP): Low price DA conditions reflecting the PreUkraine scenario.
IV. High Price (HP): High price DA conditions reflecting the HighGas scenario.

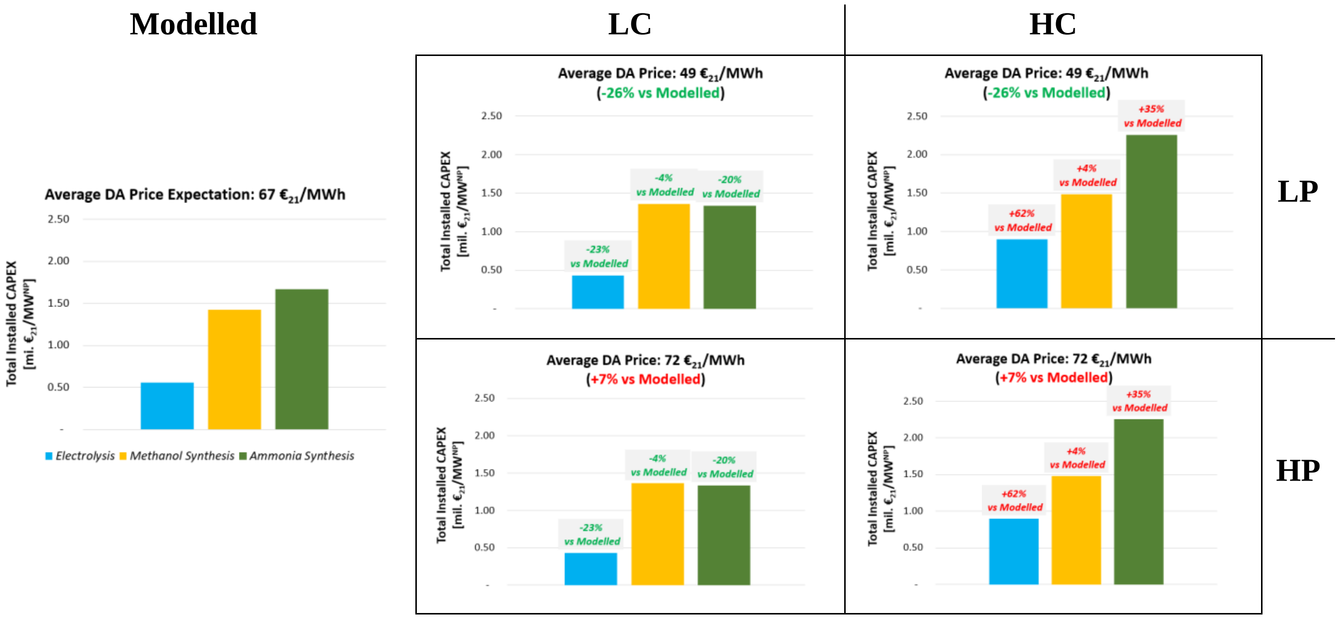


Figure 31. PtX pricing sensitivity matrix

Undertaking the same methodology, described in paragraph 2.3.1, the impact of such combinations on the optimised total PtX asset capacity (when disregarding hydrogen storage and its supporting electrolysis capacity), can be seen in **Figure 32**. It becomes apparent that the main driver over installed capacities is estimated to be the DA market pricing within the potential ranges of fluctuation. A combination of low prices and high CAPEXs seem to negatively affect the most PtX investments and vice versa. The explanation on such tendencies lies within the fact that when the model is forced to produce and utilise 48GWh of H_2 by the electrolyser without any monetary returns, then in case of high DA pricing the possible DA participation shadows any investments and the model tries to produce those H_2 targets the fastest possible in order to lose the minimum amount of DA participation.

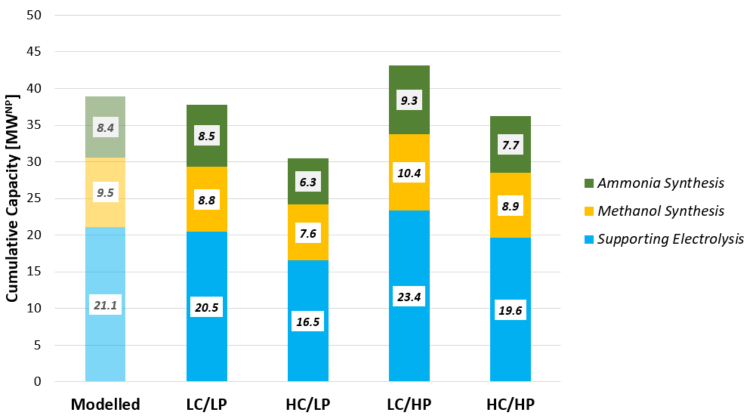


Figure 32. Total installed PtX capacity sensitivity

By up-to-date technological forecasts, the electricity pricing seems to be having the lead over the definition of the necessary PtX fuel pricing. The dynamics between price/capex scenarios and the impacts on total installed capacities and necessary PtX fuel pricing can be confirmed via a look in **Figure 33**. There, it is evident that in order to recover the optimised investment and make equivalent amount of returns for the EH as a whole in comparison with pure RES-to-Grid trading while remaining market competitive (lowest possible PtX fuel price), the low DA price cases are having the first word. Combinations of both low spot-market pricing and low 2025 CAPEX forecasts are already pushing the green PtX fuel pricing slightly below the higher end of the 2050 expectations, discussed in paragraph 4.1 (0.25-0.63 $€_{21}/kg_{MeOH}$ [Ref 30], 0.31-0.61 $€_{21}/kg_{NH_3}$ [Ref 31]).

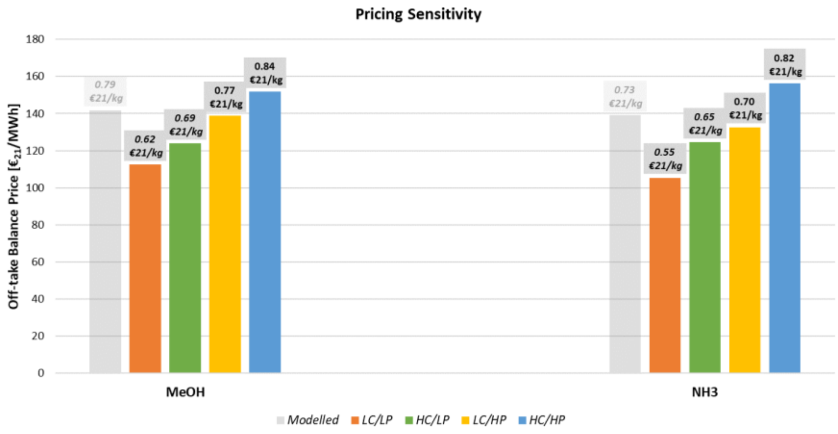


Figure 33. PtX pricing sensitivity

4.6.2. NPV Sensitivity vs Internal Pricing

Following **Figure *24***, it becomes eye catching that the monetary volume of internal trading is considerably comparable to the volume of external sales. For this reason, it is to be expected that fluctuations over the optimal internal prices consequent into significant changes in revenue distribution among investors.

The present paragraph will examine such effects by deviating the internal electricity pricing from RES generators towards PtX assets around the suggested values (**Figure *21***), while preserving the same dispatch results obtained from paragraph 4.2. The fluctuation points are determined as follows:

I. Low (-17.4% vs Reference): Average of relative change from reference values of WT and PV towards the experienced average 2030 RES capture price (nominal) for the lowest DA price scenario (PreUkraine: WT: 37.4€/MWh, PV: 31.8 €/MWh)
II. Mid-Low (-8.7% vs Reference): Average of I and III.
III. Reference: Suggested internal pricing in **Figure *21*** (WT: 46.7€/MWh, PV: 37.0 €/MWh)
IV. Mid-High (+12.7% vs Reference): Average of III and V.
V. High (+25.4% vs Reference): Average of relative change from reference values of WT and PV towards the European P^{25} PPA index at the end of 2021 [Ref 38] (WT: 56.9 €/MWh, PV: 47.9 €/MWh).

A couple of inclinations emerge while deviating the internal electricity price levels from their reference point. The more the internal electricity prices rise, the more relative benefit is harvested from the PV generator, mainly due to its low reference point vs the considerably high WT one. In parallel, the electrolyser's internal selling price is increasing in order to recover the total investment for both electrolysis and H_2 storage assets, which when combined with the higher internal electricity price significantly worsens the experienced MeOH and NH_3 profits to the point where the MeOH asset is just hitting break-even at the higher end of the internal price spectrum. It has to stay in mind of course that the only assets that are allowed by the model to go below their break-even point are the hydrogen storage due to being an extension of the electrolysis plant, and both PV and Battery assets due to being supported by the WT as part of the same investor (exogenously defined).

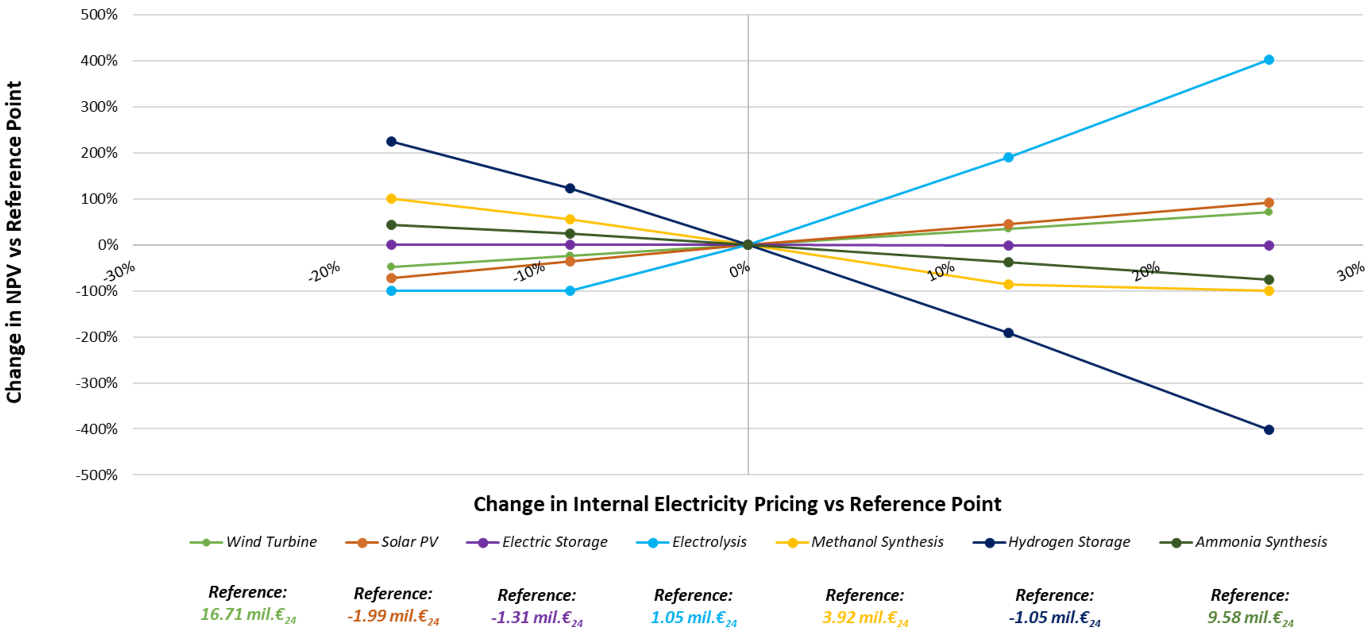


Figure 34. NPV sensitivity – Results

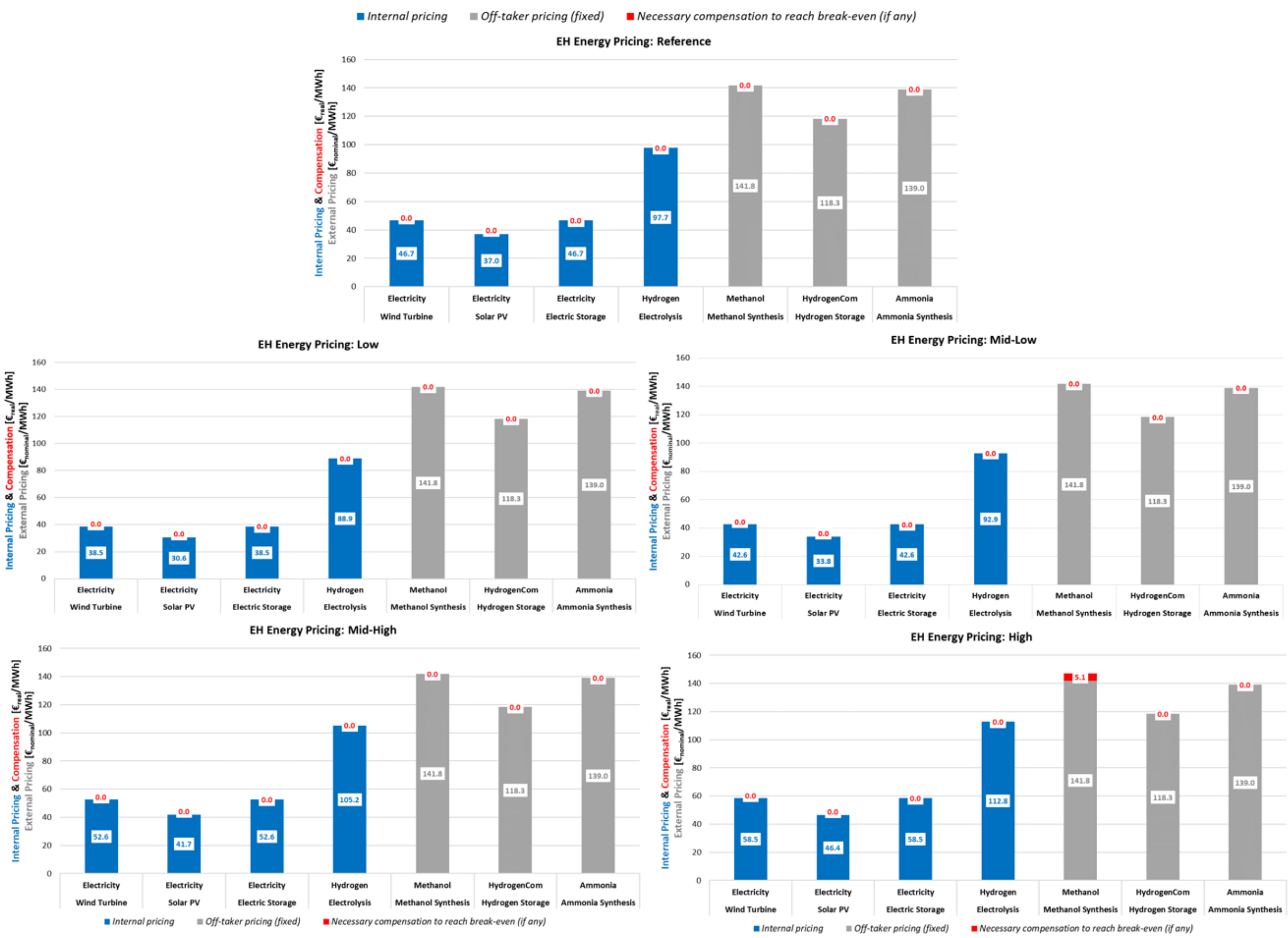


Figure 35. NPV sensitivity – Internal Pricing

Reversely, when internal electricity prices are being pressed downwards, the financial impact on the PV generator is sharper in contrast to the WT due to its lower annual production and thus higher dependence on the EH pricing. Concurrently, the Electrolysis plant is dropping its prices to host higher returns for the EH as a whole and subsequently operates for just its break-even point, while the residual PtX assets blossom further, with the ones having the lower reference point enjoying the highest relative benefit. An overview of the EH commodity pricing for each case along with the necessity for unit specific compensations can be seen. The liable party definition for the payment of such compensations has not been within the scope of the current analysis due to time limitations and is listed as future work. Thus, compensation of one unit is not burdening any other specific investor at this point in **Figure *34*** and is considered to be getting paid by external funds that such EH's receive.

The electrolyser in the present analysis operates as the middle cog in a supply chain, making just as much returns as it "requests" via its WACC plus any additionally necessity to cover losses from the hydrogen storage, and then leaves a profitability margin for the RES generators and PtX fuel assets. So it would have to be expected that the electrolysis investor would either incorporate any additional profitability in the utilised WACC, either it would impose further pricing constraints similar to the ones imposed for the internal electricity pricing range in paragraph 4.3. In such case of an additional imposed requirement of higher internal H_2 pricing, as expected the profit distribution would significantly differ from the reference case (**Figure *25***) and the overall EH profits would diminish from their so far known optimal point (26.91 mil.€$_{24}$), mainly due to differences on profit allocation and subsequent taxation, as can be seen in **Figure *36***.

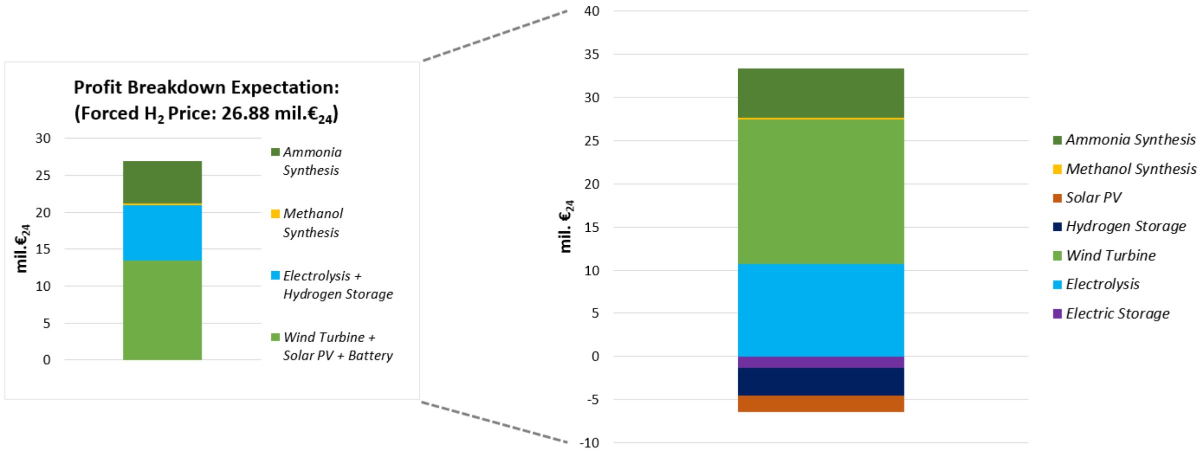


Figure 36. NPV sensitivity – H_2 pricing

On the whole, it has to be stressed once again that these results are optimal actor relationships under a no-commitment of volume-wise internal trading, while in real world those internal prices would come with minimum annual delivery commitments which would then have an additional impact on the observed NPV sensitivities, something that will be touched upon the upcoming paragraph (4.6.3).

4.6.3. Profit Distribution Sensitivity vs PPA Style Internal Commitments

Given that the prevailing analysis assumed an altruistic behaviour of all actors towards the optimisation of the overall welfare, it would be interesting to stress the changes that would occur in cases where further bilateral commitments come into play. For this reason, a PPA style contract will be employed between the RES generators and the PtX assets, where the RES generators will be primarily interested to maximise their profit while the PtX assets to minimise their electricity costs, all in parallel to the EH's return maximisation. The contract will from the one side reflect the price tag of internal electricity showcased in **Figure 21** (WT: 46.7 €/MWh, PV: 37.0 €/MWh), while minimum levels of annual delivery commitments will be set to play. Those levels are defined based on the analysis of the nominal price levels of the DA price expectation across scenarios for the 4 chosen representative years. An assumption will be drawn where the EH would be interested to receive higher amounts of energy in relation to what it would cumulatively buy from the grid on average at the given price tags minus the grid tariff, while RES generators would be interested to commit to levels below the expected cumulative amounts that they would sell to the grid under the given prices. By averaging those perspectives, a minimum annual commitment of 54.3GWh for WT and 11.4GWh for the PV plant. By feeding this internal pricing and lower bounds of annual delivery into the dispatch optimisation, the following results are being shaped.

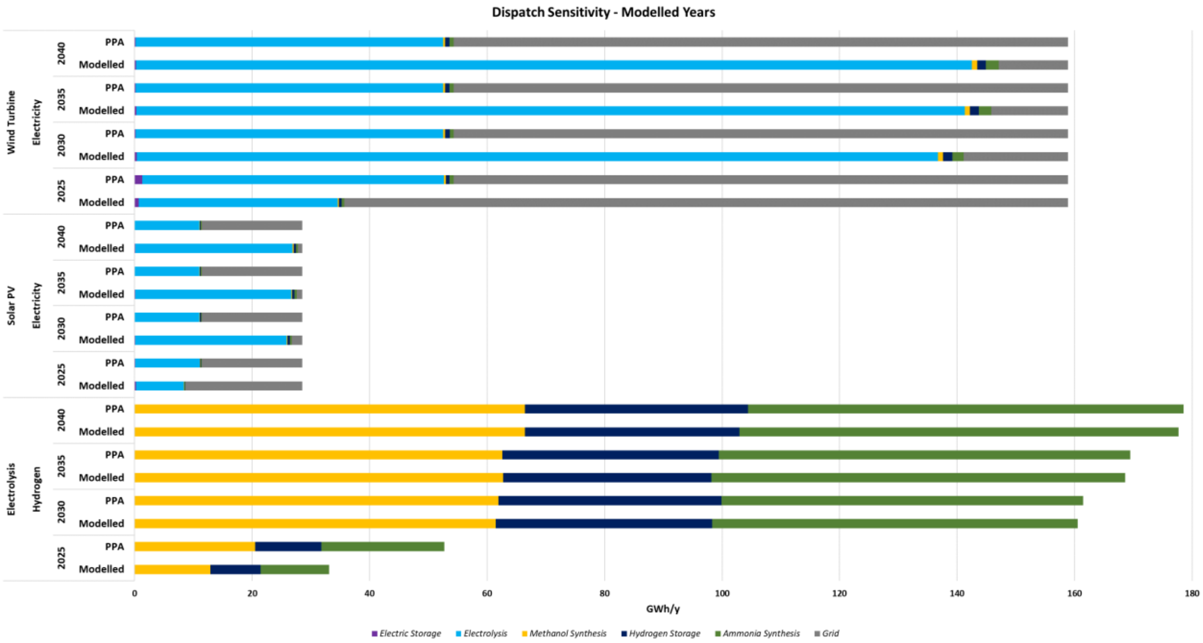


Figure 37. Dispatch sensitivity

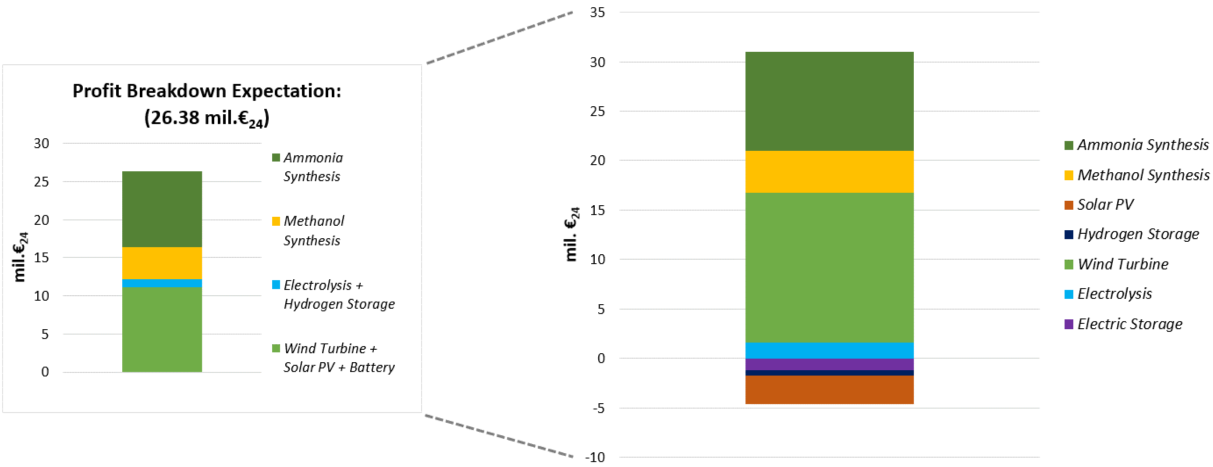


Figure 38. Profit distribution sensitivity (expectation)

Evidently, such a style of setup brings up two phenomena. From the one hand, RES generators are obligated to internally deliver higher amounts of electricity earlier on in the optimisation period, when the model decides that it is a win-win situation for the EH. On the other hand, the EH can source its electricity from the grid when prices (including the grid tariff) are low. The overall profits, as expected, slightly decrease, and the distribution benefits PtX assets more on expectation (**Figure** *38*). However RES generators have more secure returns in case that scenarios with low DA pricing realise (**Figure** *39*), in comparison to the core analysis (**Figure** *25*, **Figure** *28*).

Of course, the present section does not aim on the development of any sophisticated approach over the definition and terms of such bilateral contracts, however it able to bring to the surface the implications that may arise and the advantages that various flexibilities can offer to all investors, when comparing the core analysis with more restricted cases.

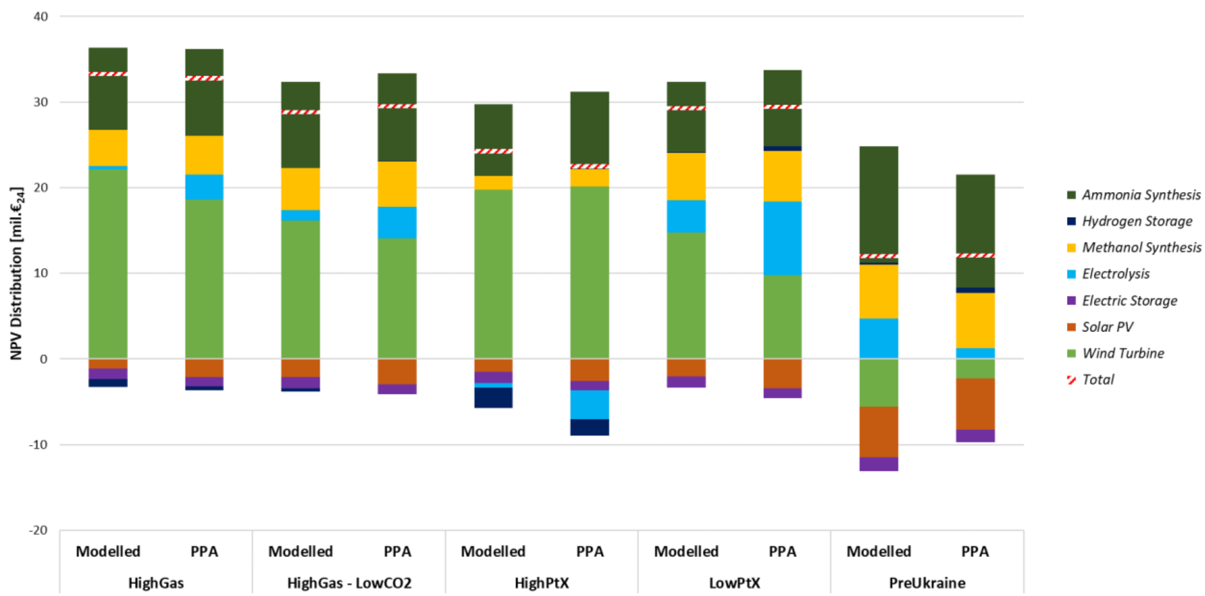


Figure 39. Profit distribution sensitivity (realisation)

4.6.4. Further Suggested Sensitivities

With a low availability on time within a Thesis timeframe, a lot of aspect investigation have to be listed as future work. Some of those that would potentially provide useful insights in the opinion of the author can be found below:

I. Sensitivity over the investors' WACC perception due to the impact on discounting. Investigation of shift between technologies.
II. Further look into the impact of the design of PPA style long term contracts. Changes of profit distribution and examination of the benefits that flexibilities related to pricing but also over annual deliveries could bring to all investors.
III. Sensitivity of benefit allocation from the addition of 1 additional capacity unit of a specific plant. Indications on who should pay parts of the investment.
IV. Sensitivity over grid tariffs.

5. Conclusions & Discussion

5.1. Reflection Upon Results

Taking into consideration the entirety of the presented analysis while cross examining the results with international literature, it becomes apparent that the interest switch of RES generators towards participation in EHs can come with not that high counterfactual green PtX fuel pricing, as of the up-to-date information and showcased assumptions. The resulting necessary PtX pricing proves to be competitive with future outlooks of green fuels, however the competitiveness over conventionally produced fuels is still falling considerably behind. Of course, this scenery is expected to be overturned in the future due to increase in conventional fuel costs but also carbon pricing, however investments in green setups in the foreseeable future may prove to require a further constitutional push in order to match the market's levels faster. Additional studies like the present one can shed more light in all aspects of the green fuel production benefits and act as a spark for upcoming policy changes.

From an economic aspect of the Danish reality, it seems like RES generators in most price scenarios are better off striking an EH deal on the long run than trading purely with the grid. This of course requires a satisfactory level of an internal long-term contract, which further stresses that the formation of EHs in the short-term future will be a win-win for both RES generator and PtX sides. The former will be able to request higher electricity pricing, while the latter may sacrifice some revenues in order to be front runners in the early-stage market of green fuels, as the results prove to be encouraging even with relatively high internal pricing.

All in all, even through the ongoing energy crisis, the derived results seem promising from a private economic point of view. Regaining quickly the interest of RES generators on new unconventional ventures will be the key to a quicker green transition, especially for the hard-to-abate sectors relying on green PtX fuels like the examined ones.

Zooming out and reflecting on the contribution of such hubs on the overall green transition, the initial indications seem promising, with the assessed EH directly translating to 2/3^{rds} of the PtX fuel generation. Nevertheless, sourcing the residual electricity from green providers via the grid purely moves the problem to other people's hands rather than solving it. Quicker institutional push towards the competitiveness of the derived levels of PtX pricing in the market would pass the signal to all sorts of investors and the market will find its way to higher levels of climate friendly commodities without restricting other sectors to do so. The inevitable transition of DA prices to levels of 40 €/MWh would require sophisticated handling for the interests of all sides. Constant research with the most updated means would gradually emerge the new reality. Time will show.

5.2. Suggested Future Work

A plethora of extensions to the present methodology can provide further insights in the debates over EH formations. For instance, competitive investment selection of PtX assets based on fuel demand expectations would result in a more optimal portfolio of assets. Of course, the more versatile a portfolio is, the more flexible the EH can prove to be, which then leads in additional future research. Furthermore, the analysis of the benefit distribution by expanding a specific unit marginally could be analysed and shed light on who should contribute for the expenses of unit expansions.

In general, flexible pricing/delivery schemes in conjunction with a revenue redistribution potential could shield the EH's investments against specific disturbances on the market. The optimal structure of bilateral contracts could be a really interesting space for research, revealing the dynamics of such relationships and thus obtaining direct interest from investors themselves.

From a modelling standpoint, the inclusion and evaluation of more than 1 levels of uncertainty (e.g. DA market prices and wind profiles) as well as the interactions between those would provide crucial insights for short term operational forecasts of elements such as the electricity market price in more than 1 market, which would then allow for more strategic operation. This as expected would require such markets to be added on the model, if considered that they are vital for the early-stage investment optimisation. If not, 2 versions of such models could be combined, one for investment expansion while the other for short term operations, with different aims on the uncertainty utilisation. Finally, more advanced modelling approaches can be utilised incorporating the investor risk perception, such as adjustable robust optimisation (ARO), while game theoretic approaches can be also evaluated in order to prove the stability of the concept of an EH.

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