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How big is big enough? Cost-optimal design for centralized and decentralized e-SAF production

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ABSTRACT

Converting biogenic CO_2 into synthetic sustainable aviation fuel (e-SAF) requires significant amounts of renewable energy, and alignment between system elements and sizes. However, the optimal scale and configuration of CO_2 electrolysis remains unresolved. This study examines the economics of RFNBO-compliant e-SAF production from CO_2 electrolysis via Fischer–Tropsch synthesis in centralized and decentralized configurations in the Netherlands. A two-stage optimization framework sized the renewable generation, storage, and use of grid electricity for electrolysis plants (9–900 MW). The model projects scenarios from 2025 to 2050, including expected cost and efficiency improvements. The lowest near-term (2025) levelized cost of e-SAF (around 5230 EUR_{2019}/tonne) is achieved for a centralized 90 MW electrolysis plant powered by onshore wind and photovoltaics. A 23 MW decentralized system yields comparable costs. While conversion investment costs are higher at smaller scales, they are counterbalanced by avoided grid fees, higher allowed grid mix electricity consumption, and lower CO_2 supply cost. By 2050, decentral e-SAF production costs are projected at 2750 EUR_{2019}/tonne (a 35–70% premium over current SAF prices). These systems provide a near-term route for demonstration projects by co-locating renewable energy, e-SAF production, and regional airports. However, two fundamental caveats remain. First, the cost of CO_2 electrolysis–based fuels is incompatible with bulk fuel margins. Second, the limited production volumes from a decentralized configuration are misaligned with the high demand of the aviation sector. Therefore, CO_2 electrolysis appears best deployed in a high-value niche product or where high-quality renewable resources geographically overlap with distributed biogenic CO_2 streams.

1. Introduction

The aviation sector is considered one of the most challenging sectors to decarbonize [1]. The transition from fossil fuels to sustainable aviation fuels (SAF) has been put forward as the main strategy to reduce its emissions [2]. However, despite ambitious policy targets, SAF production in Europe is failing to take off. Recently, several high-profile projects have been paused or cancelled, such as Shell's 820 kilotonne SAF/year biofuels plant in Rotterdam [3], Uniper's *SkyFuelH$_2$* e-SAF project in Sweden [4] and Haltermann Carless' planned SAF facility in Speyer, Germany [5]. These setbacks illustrate the difficulty of moving from ambitious targets to actual large-scale production. Our previous work concluded on a similar note [6]. The study examined syngas production from CO_2 electrolysis as an intermediate feedstock for SAF in the Netherlands. In this context, with the 2030 electricity grid emissions, the price of syngas was projected to be 10 times larger than a fossil counterpart. That led to the conclusion that under the current conditions, the Netherlands does not have the conditions to pioneer CO_2 electrolysis (CO_2E) to SAF projects. The current work re-evaluates key assumptions from our previous study regarding the size of the electrolysis plant and potential cost improvements in future systems.

In our previous work, system elements, like electricity generation and storage, were sized around a fixed-size electrolysis plant. The size of the electrolysis plant was chosen to align with a small-scale industrial Fischer-Tropsch (FT) plant [7] and benefited from economies of scale in the FT synthesis [8].

However, since electricity supply dominates the levelized cost of syngas [9,10], the electrolysis plant can also be specifically tailored to be coupled with a hybrid mix of onshore wind and solar photovoltaics (PV). This configuration was found in our previous work as the most

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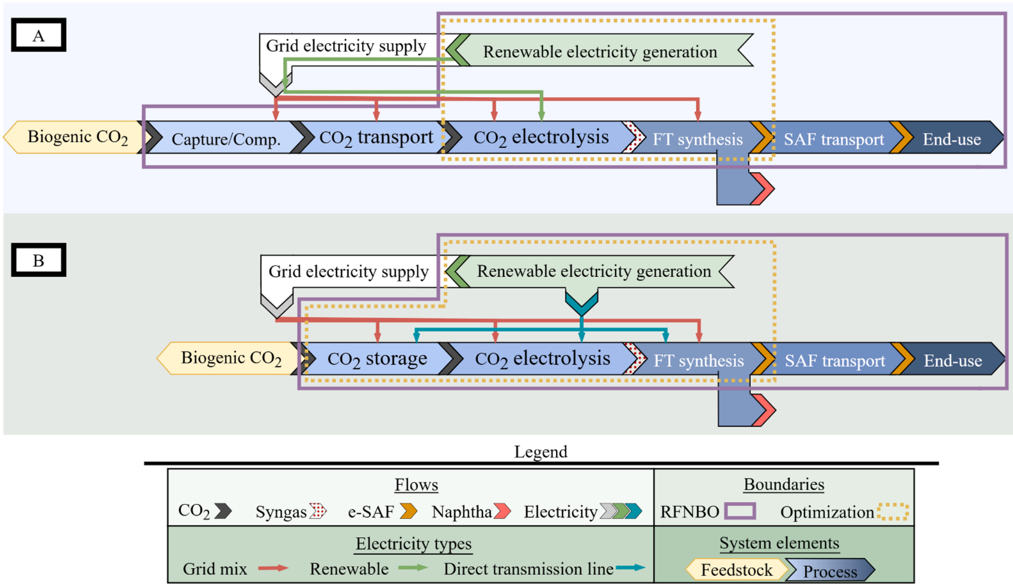

Fig. 1. Case overview regarding the considered system elements of the centralized (A) and decentralized (B) cases. The annualized cost of the elements within the design boundary were optimized. The system elements within the RFNBO boundary were part of the supply chain emission calculation, that determines the amount of grid mix electricity which can be consumed each hour.

cost-effective [6]. However, due to limited land availability in the Netherlands, dense spatial planning, and strict permitting requirements, the maximum capacity of onshore wind and PV is in practice constrained [11,12].

For a large-scale 540 MW electrolysis plant in the Netherlands, electricity supply primarily from offshore wind accounted for more than 50% of the levelized cost. This creates a trade-off: while larger plants could benefit from economies of scale, they may be too large to utilize exclusively the hybrid mix of onshore wind and solar photovoltaics. Consequently, it is unclear whether a large scale (540 MW) electrolysis plant could yield the lowest SAF production cost if it would need to follow intermittency patterns of renewable electricity.

Our previous work focused on the centralized implementation of a CO_2 electrolysis plant. The conversion system was connected to a large-scale CO_2 supply infrastructure and the electricity grid, sourcing intermittent renewable electricity from dedicated generation facilities. An alternative to the centralized system is a small-scale decentralized system [13]. In such a system, economies of scale are sacrificed [14], but, cost savings can be achieved by better adapting to local conditions [15]. For instance, CO_2 streams can be co-located with the electrolyzer, eliminating the need for an extensive infrastructure and its associated emissions. Electricity can be supplied from a direct transmission line, saving grid fees and preventing dealing with demand-congestion [16]. In a decentralized system, the cost structure is fundamentally different, with expenses distributed differently across the e-SAF production supply chain compared to a centralized alternative. However, it is unclear whether the higher CAPEX of smaller electrolyser and Fischer–Tropsch plants could be offset by potential benefits from lower CO_2 supply costs, avoided electricity grid fees, and reduced emissions.

The EU Delegated Acts (2023/1184/EC) that define Renewable Fuels of Non-Biological Origin (RFNBO) were adopted in 2023, therefore optimization studies incorporating these specific constraints are currently scarce [17]. Furthermore, the grid mix electricity consumption aspect is typically not considered in the literature beyond assessing average footprints. While our previous work addressed this gap by quantifying the effect of the grid mix electricity consumption across scenarios from 2025 to 2045, it did not account for broader techno-economic developments. To provide a comprehensive projection of the e-SAF cost in future scenarios, the analysis must also factor in that multiple system elements will simultaneously undergo improvements in both technological maturity and financial costs [18–20].

The primary objective of this work is to improve estimates of the levelized cost of e-SAF in future scenarios that meet RFNBO requirements. Specifically, this study aims to evaluate the differences between centralized and decentralized supply chain configurations, demonstrating how these different configurations could impact the optimal system sizing and overall fuel costs.

This paper is organized as follows: Section 2 outlines the case study and methodology. Section 3 presents the results of the investigated scenarios from 2025 to 2050. Section 4 discusses these findings, and Section 5 provides the conclusion.

2. Case study description and method

In this work, a centralized and decentralized system were compared. In Fig. 1A, the system elements of the centralized system are shown, which consists of: transport of feedstocks and products, CO_2 conversion to SAF and receiving electricity via the grid. The decentralized system in Fig. 1B is co-located with the CO_2 source and electricity generation. In both systems, the electrolysis plant is connected to the grid and e-SAF is transported to the end-use location.

The optimization model from our previous work [6] was expanded to account for the case differences and changes in future scenario improvements. The future scenarios relied on projections for 2025–2050, evaluated at five-year intervals. A two-stage optimization model was used based on hourly historical data regarding electricity prices and generation capacity factors from 2019 to 2024, which were consistently applied across all future scenarios. The objective was to minimize the net annualized cost of the e-SAF production system. The optimization problem is framed explicitly from the perspective of the e-SAF producer. Any revenues generated from selling excess electricity to the grid are fully allocated to reduce the final levelized cost of e-SAF.

- First Stage (Sizing): Determined the optimal size of: (i) electricity generation, (ii) electricity storage (battery), and (iii) CO_2 and syngas storage.
- Second Stage (Operation): The sizes of the equipment were fixed and operational decisions (e.g., use of grid electricity, electrolyzer, and storage assets) were re-optimized. Additional revenues were

generated in this stage by selling electricity to the grid at the prevailing hourly day-ahead market price [21]. This occurred when renewable generation exceeded the plant's demand or when market prices were favorable. These revenues were allocated to the e-SAF production and reduce the levelized cost of production.

The CO_2 electrolysis plant produces syngas, which is further converted into naphtha and e-SAF using FT synthesis, see Fig. 1. To address the multifunctionality of the system where e-SAF is the target product, the costs of the system were allocated between naphtha and e-SAF using economic allocation factors. e-SAF accounted for 80% of the end product flow, and holds 90% of the economic value [22]. Consequently, 90% of the total system costs are allocated to e-SAF production, while the remaining 10% are attributed to naphtha as a by-product. In the optimization model, the size of the electrolysis section within the e-SAF plant was a fixed parameter. This was an input in the optimization, and the rest of the equipment was sized around this input size. The goal of the optimization was to explore the effect of electrolyzer size on the sizing and cost of the surrounding equipment.

2.1. Centralized case

Like in our previous work, the CO_2 electrolyzer was assumed to be placed in the chemical cluster in Rotterdam. Syngas was not transported, as the electrolysis plant was assumed with be co-located to the FT synthesis plant. The costs (CAPEX and OPEX) of the FT synthesis plant were included in the optimization, with more details presented in SI 3.

The CO_2 was supplied from a dedicated biogenic CO_2 infrastructure (see Appendix D), to guarantee the biogenic origin of CO_2, a requirement for RFNBO certification from 2041 onwards. It was assumed that at any given moment, the desired amount of CO_2 was available to the e-SAF plant. When the e-SAF plant was not operating or operating at a partial load, the excess CO_2 was was routed to carbon capture and storage (CCS). In this way, the continuous stream of industrial CO_2 can be coupled with the intermittent operation of the renewable-driven e-SAF plant as any unutilized biogenic CO_2 is permanently stored. A key requirement for meeting the RFNBO regulation is that across the total e-SAF supply chain a 70% global warming potential (GWP) reduction should be realized compared to a fossil benchmark. RFNBO regulatory compliance requires calculating the emissions from the production of the fuel across its entire supply chain until end-use. In RNFBO emission accounting, construction, decommissioning and end-of-life emissions are not included. Therefore, the analysis accounted for emissions arising from the electricity consumption of the FT plant and CO_2 infrastructure, fuel transport using diesel-fuelled trucks from Rotterdam to Schiphol (round-trip of 150 kilometers), and final end-use. The used emission factors for the different supply chain stages were dependent on the grid's global warming potential, which changed across future scenarios, see SI 1, SI 2, and Appendix C.

The difference between the regulatory emission threshold and these background emissions defines the carbon budget for the CO_2 electrolysis plant. Specifically, this budget represents the allowable emissions margin that can be filled by consuming grid electricity while remaining compliant. Therefore, the plant is permitted to consume grid mix electricity with its associated emissions; however, the amount is constrained each hour to ensure that the GWP of the product remains under the RFNBO threshold. From the background emissions and the GWP threshold, the maximum hourly consumption of grid electricity was derived. For specific details, the reader is referred to our previous work [6].

The electrolysis plant and individual renewable electricity sources all have their own grid connection. In the centralized configuration the renewable electricity is fed via the grid to the electrolyzer. A grid fee for receiving electricity of 18 EUR_{2019} per MWh was charged [23], whereas for self-consumed electricity, a fee of 90% to this standard rate was applied. This differential pricing was implemented to prevent the model from simultaneously buying and selling electricity. All other transaction costs and taxes were excluded.

To reflect realistic spatial constraints within the Dutch context, upper capacity limits were imposed on land-based renewable sources. Specifically, capacities were capped at 193 MW for PV and 567 MW for onshore wind (10% larger than the largest currently planned PV and onshore wind farms [24,25]), while offshore wind remained unconstrained.

The capacity of the FT plant is a decision variable in the model. The plant is constrained to operate between 70% and 100% of its installed capacity [26]. Based on Boilley et al. [22], a non-linear cost function for the FT plant was derived over a broad range of 13–257 MW (24–478 ktonne e-SAF capacity/year). A scaling factor of 0.79 was derived at a reference capacity of 96 ktonne e-SAF/year, for a reported CAPEX of 730 $MEUR_{2019}$/year. Since the optimization model only accepts linear equations, the FT plant cost function was linearized. The electrolyzer size is an input into the model, based on this, the size of the FT plant can be estimated when under continuous operation. Using this information, the possible cost of the FT plant is linearized over a narrow capacity range (between 70% and 100% of the expected capacity). For more details regarding the cost estimation of FT plant, see SI 3.

Four different electrolyzer sizes were investigated: 90, 270, 540, and 900 MW. 90 MW corresponds to the size of a single system in Noordende et al. [27]. Beyond this size, it was assumed that the electrolysis plant scales up linearly by number, i.e., larger plant sizes were reached by duplicating the same 90 MW system. For more details regarding the case, please refer to the case section in our previous work [6].

2.2. Decentralized case

The decentralized case was assumed to be located at a biomethane plant in Coevorden, the Netherlands with a CO_2 flow estimated at 30 ktonne CO_2/year [28]. In Europe, there are currently only 5 biomethane plants that are larger than this plant. CO_2 separation is an intrinsic part of the biomethane production process and was assumed to meet the specifications for the CO_2 electrolyzer. Also, no upstream emissions were allocated to the CO_2 supply following Life Cycle Assessment (LCA) guidelines, where upstream emissions are allocated to the methane.

Unlike the centralized case, only CO_2 from this specific source, without a connection to CCS infrastructure, was considered. To facilitate matching the CO_2 supply with the electrolyzer operating at partial load, a temporary CO_2 buffer option was implemented in the model. Additionally, the option to vent biogenic CO_2 into the atmosphere was also included. Liquid CO_2 was stored at 15 bar and $-28.4\,^{\circ}C$. The cost for a liquefaction plant was based on Nguyen & Kim [29]. The cost of the insulated CO_2 tank costs were based on a CO_2 tank quote of Pentair [30]. In both cases, as storage technologies in this work are modular, economies of scale are not included, and instead linear scaling was applied. It was assumed that the liquefaction plant could ramp down to 50% of its capacity based on a supplier datasheet [31]. Reconditioning the CO_2 after storage was not included in this study. Detailed information on the specific cost data is provided in SI 5.

Both, the electrolysis and FT synthesis plants, were co-located with the CO_2 source. This configuration results in a shorter supply chain compared to the centralized case. In the decentralized case, the source of electricity from the FT plant could be from both direct renewable electricity or the grid. The source of electricity used in the FT synthesis was an optimized variable, and impacts the GWP of the product. The total amount of grid electricity which can be consumed was constraint to comply with RFNBO regulatory requirements.

Background emissions from fuel transport to the airport and end use of the e-SAF were included in the GWP of the product, which impacts the maximum amount of grid mix electricity consumed in the production of e-SAF. In this case, the e-SAF was assumed to be transported to the Groningen Airport Eelde (GRQ), a small regional airport in the north of the Netherlands, with an annual amount of kerosene estimated at 6.8

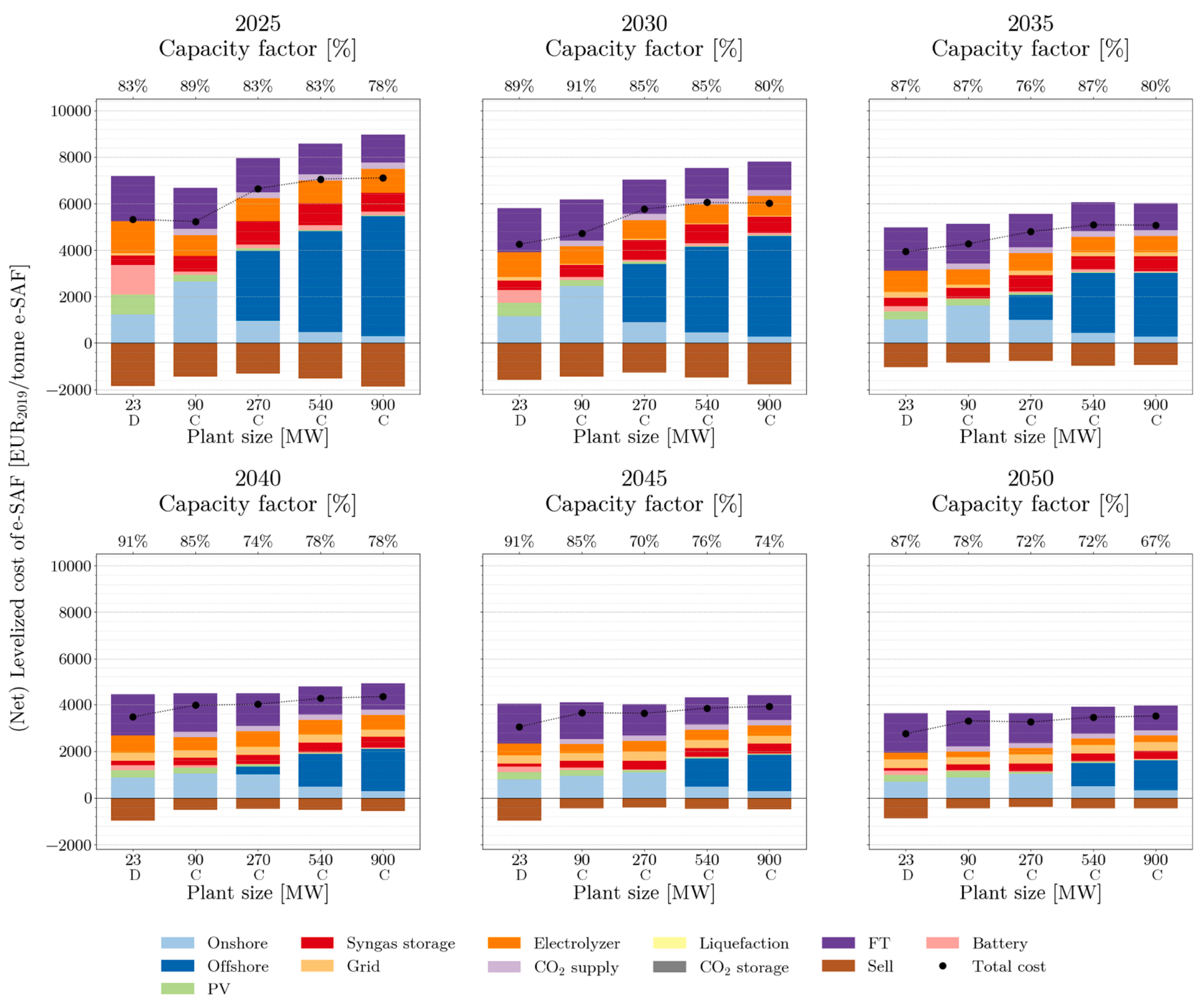

Fig. 2. Overview of the cost categories of different scenarios from 2025 to 2050 at different scales. The 23 MW plant size is chosen as the representative size for the decentral cases denoted with D and the plant sizes larger than 90 MW are centralized cases denoted with C. The top axis presents the optimal capacity factor of the electrolyzer that results in the lowest net levelized cost of e-SAF.

ktonne (Appendix A). Using a conversion factor of 0.26 tonne SAF per tonne CO_2 [22], and 30 ktonne CO_2/year from the biomethane plant, 7.7 ktonne of e-SAF could be produced. This e-SAF output closely matches the fuel demand of the Groningen Eelde Airport. A round-trip distance of 130 kilometers was assumed for transporting the fuel to the airport.

To match 30 ktonne CO_2 annually, both the FT and electrolysis sections were scaled down compared to the centralized case. Economies of scale were lost, and the unit production cost increased; for more information, see SI 3.

Electricity was assumed to be produced locally from PV, onshore wind, or a combination of both. The electricity was delivered via direct transmission lines to the e-SAF plant. The plant simultaneously served as the point of interconnection with the grid, allowing it to sell excess renewable electricity and purchase additional power when needed. In this configuration, also a grid fee of 18 EUR_{2019} per MWh was applied for consuming electricity from the grid, whileno grid fees were charged for utilizing self-generated electricity.

Because the generation assets and the e-SAF plant are co-located at the grid interconnection point, no additional costs for long-distance dedicated transmission lines were applied. Instead, the local electrical infrastructure required to connect the renewable sources to the e-SAF plant and the grid is accounted for by including grid connection costs in the capital expenditures (CAPEX) of the renewable energy installations.

It was assumed that economies of scale play a role in scaling up the electrolysis plants between 9 and 90 MW. For the electrolysis plant, a scaling factor was used based on an analysis of the Store and Go project [32,33]. A scaling factor of 0.75 was used at a 90 MW reference scale based on a CAPEX of 2000 EUR_{2019}/kW for more information see SI 4. Different sizes of electrolyzers were modelled, with sizes ranging from 9 MW to 36 MW, with a 4.5 MW interval. In the centralized case study, a single module was 9 MW and consisted of 6 hotboxes. In the decentralized case, due to the smaller scale, the modules were 4.5 MW, containing 3 hotboxes. The hotboxes could be operated individually. It was assumed that the electrolysis plant could not be turned off; instead, it entered a hot-standby or minimum operation state from which it could be ramped up to full load. In the hot-standby state, a hot box consumed 7% of electricity without producing syngas [34].

In literature, hot boxes typically operate within a restricted 80–100% load range [35]. Due to the limited number of hot boxes (6–24) in the decentralized case, the electrolyzer's aggregate power consumption cannot be modulated continuously from hot-standby to full load. Instead, the load profile is discontinuous and characterized by operational gaps. The model sets the minimum operation load of the electrolyzer at the threshold where the output of all the individual hotboxes overlaps to form a continuous range up to 100%. Practically, while a 9 MW electrolyzer with 6 hotboxes is limited to operating in hot-standby or between 53.3% and 100%, a larger 36 MW electrolyzer has a much wider operating window, with a lower limit of 13.3%. Note that in the centralized cases, due to the large number of hotboxes, the plant can modulate continuously between hot-standby and full load. For the calculation method used to estimate the minimum operation load, please see SI 6.

2.3. Scenarios regarding future improvements

The scenario analysis evaluated potential future improvements to the elements listed in Appendix C, classified into four categories: (i) cost, (ii) process yields, (iii) capacity factors, and (iv) operational bounds. The cost category influences the generation of renewable energy as well as the costs of battery storage and the electrolysis plant. The process yield category affects the carbon and electrical efficiency of both the FT plant and the electrolyzer. Improvements in the RES generation capacity factor increased the energy production per unit of installed capacity. Finally, the operation bounds reflected advancements in the conversion technologies, enabling effective operation even at lower capacity factors.

For more information regarding the used input values in the model, see SI 3. A 5-year development timeline, from the project's start until full operation, was assumed. The investment costs were fixed at the start of the project, and 20 years of full operation were assumed. Scenarios from 2025 to 2050, with 5-year intervals were evaluated. The listed year referred to the project's starting date. The model was solved for each capacity in the different cases, namely 7 decentralized and 4 centralized configurations. Finally, the operation of the fixed capacity electrolyzer was solved for 20 different yearly average capacity factors, ranging from 50% (4380 full load hours (FLH) per year) to 91% (8000 FLH per year). In this way, the optimal number of full-load hours of the electrolyzer was determined. In total, both stages of the model were solved to optimality on the Delft High Performance Computer with 8 cores and 16 GB of RAM [36].

3. Results

3.1. Levelized cost distribution among system elements

Fig. 2 presents the net levelized cost of e-SAF production for the decentralized (<90 MW electrolyzer) and centralized (>90 MW electrolyzer) cases. For each case, a capacity factor was selected which results in the lowest levelized cost of e-SAF production, presented on the top axis of Fig. 2. While multiple plant sizes (9–36 MW) are evaluated for the decentralized case, the analysis in this section focuses on the 22.5 MW electrolyzer (hereafter referred to as the 23 MW electrolyzer). This case results in a system with the lowest levelized cost of SAF from 2030 to 2040. For an overview of the cost of the other decentralized plant sizes and their cost categories, see Appendix B.

3.1.1. 2025 scenarios

The results indicate that a 23 MW electrolyzer operates optimally at a capacity factor of 83%, while intermediate syngas storage enables the FT section to maintain a higher capacity factor of 91%. Electricity generation using PV and onshore wind accounts for 29% of the total cost, with 59% of the electricity generation cost attributed to onshore wind and 41% to PV. Due to the higher unit cost at a smaller scale, the cost of the FT and electrolysis section of the plant accounts for more than 45% of the costs. A battery of 115 MW (5 times the size of the electrolysis plant) accounts for 18% of the net levelized cost of e-SAF. The battery provides several benefits to this design. (i) It supports the electrolyzer by providing the minimum required electricity to support the hot standby state. (ii) The battery effectively compliments PV generation by compensating for day-night fluctuations. (iii) By decoupling the moment electricity is generated from the moment electricity is sold, it gives the opportunity to sell electricity at a higher price. Relative to a baseline where no electricity is sold, this strategy results in a reduction in the production cost of approximately 2062 EUR_{2019}/tonne e-SAF.

While the 23 MW decentralized design can supply a smaller e-SAF demand, it is cost competitive with the 90 MW centralized alternative for three main reasons. (i) It has a lower amount of supply chain background emissions. Therefore, 21% of the electricity consumption in each hour could be sourced from the grid compared to just over 1% in the 90 MW case to comply with RFNBO regulations. This aspect reduces the need for overcapacity in generation. Overall, the effect of the grid mix electricity on the cost is small (less than 2%). (ii) Since the system is co-located next to a concentrated CO_2 supply, there are CO_2 supply (in capture, compression, and transport) cost savings of 293 EUR_{2019}/tonne e-SAF compared to the centralized cases. (iii) The electricity supply is independent of the grid and the associated grid fees. This is reflected by a lower generation cost compared to a centralized system.

The 90 MW electrolyzer results in the lowest levelized cost of 5230 EUR_{2019}/tonne e-SAF; however, the 23 MW case is comparable, increasing cost by less than 2%. The generation of electricity mostly from using onshore wind and accounts for roughly 37% of the total levelized costs of e-SAF. Conversion (including the FT and electrolyzer section) accounts also for 37% of the e-SAF cost. The battery is sized at 53 MW with a storage capacity of 212 MWh (4-hour duration) in the 90 MW case, accounting for a minor share of the total cost (<2.0%). The model selects to oversize wind generation with a smaller battery.

By oversizing wind capacity, there is the possibility to sell excess electricity, which is an integral part of the business case surrounding this sizing strategy. However, due to the small size of the battery, the strategy is less effective compared to the decentralized case, with a revenue of approximately 1600 EUR_{2019}/tonne SAF (including electricity sales from the battery and excess renewable electricity).

Since onshore wind has a higher capacity factor compared to PV, a smaller battery is required in the 90 MW case compared to the 23 MW case. As the hourly budget for grid electricity is limited to 1.1%, only a negligible fraction (0.1%) of the cost was grid-based.

In the 270 MW design, wind onshore and PV reaches the maximum capacities of 567 and 193 MW, respectively. Therefore, additional electricity from offshore wind is needed for the electrolyzer. The electrolyzer operates at a similar capacity factor (83%) compared to previous cases. The FT section achieves a high annual capacity factor of 91.3%, enabled by the intermediate syngas storage, which decouples the flexible-operated electrolyzer section from the continuous-operated FT section. The cost contribution for temporal syngas storage was the largest at 270 MW (13%).

Wind offshore becomes a larger cost contributor at 540 MW. The highest fraction of the cost (approximately 50%) is attributed to offshore wind. Both the battery (220 EUR_{2019}/tonne SAF) and syngas storage (1058 EUR_{2019}/tonne SAF) are necessary to operate the electrolysis section of the plant at a capacity factor of 83% and the FT section at a capacity factor of 91.3%. A similar result was found for the 900 MW case.

3.1.2. 2030 scenarios

The decentralized case becomes cheaper compared to the centralized alternatives starting from 2030 onwards, which is due to two main reasons: (i) the 23 MW case is powered by PV and onshore wind. In the 23 MW case, PV accounts for approximately 70% of the installed capacity. However, total electricity generation is roughly equal between PV and onshore wind due to the significantly higher capacity factor of the wind turbines (27% vs. 13%). Larger improvements in investment cost and capacity factor are projected for PV compared to onshore wind from 2025 to 2030. (ii) In 2030, a significantly smaller battery is required compared to 2025, driven by three simultaneous

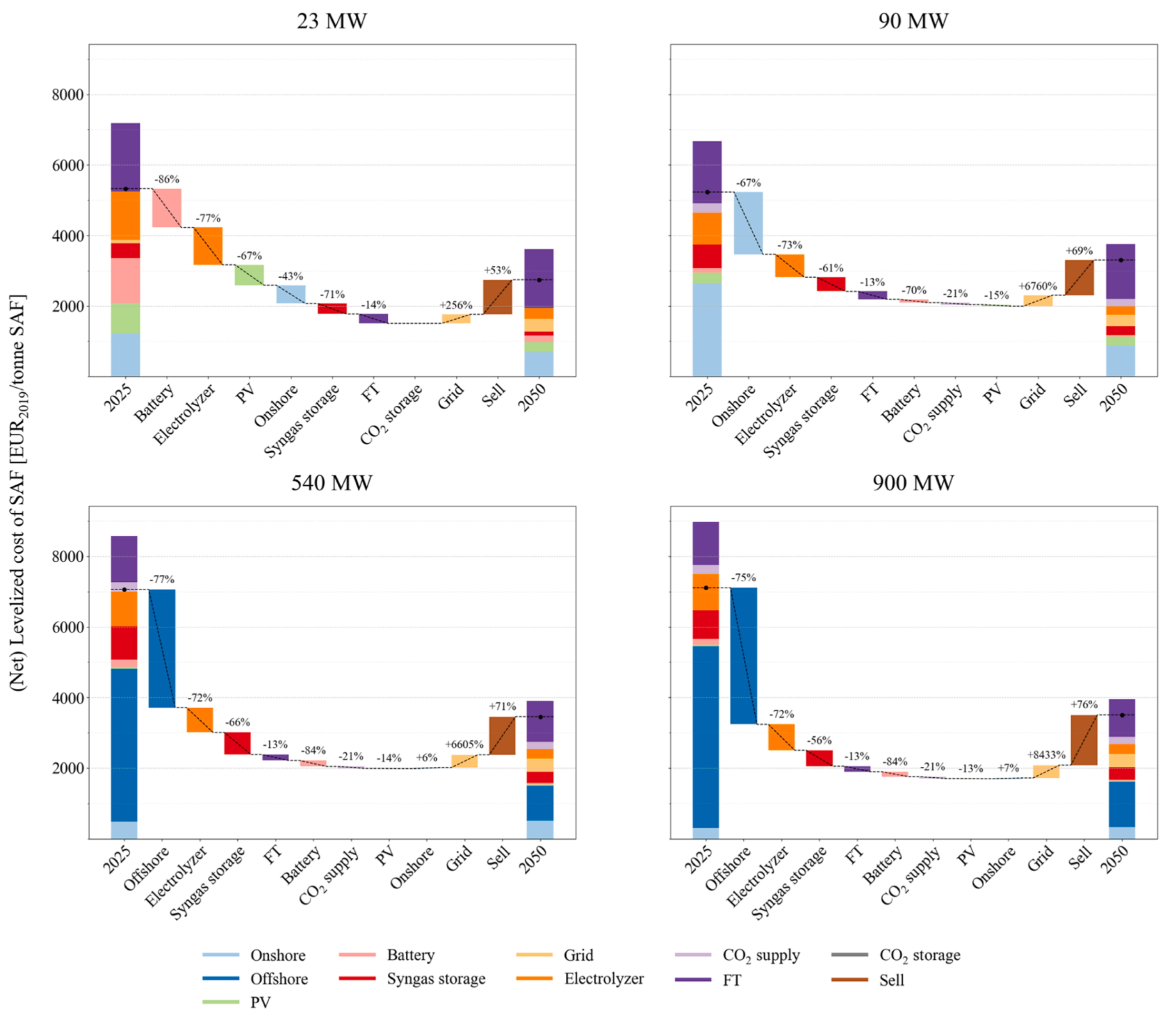

Fig. 3. Waterfall plot of the absolute change in cost categories from 2025 to 2050 across different electrolysis plant sizes. The dashed line represents the net levelized cost (levelized cost minus revenues from selling electricity). Categories are sorted by absolute impact. The percentages above the cost categories are the relative change percentages per category from 2025 to 2050.

developments. First, as a result of the improved minimum operation load of the hot-boxes dropping from 80% to 70%, the electrolyzer can operate at a lower minimum percentage of its capacity. The threshold decreases from 21% (in 2025) to 14%. Lower battery capacity is needed to ensure the electrolyzer's electricity supply. Second, the ratio between PV and onshore wind capacity changed from 2.4 to 2.1. This indicates an increased reliance on electricity from wind. Since it has a higher average capacity factor and is less influenced by day-night cycles, the battery is less necessary. Third, the maximum amount of grid consumption per hour increases by roughly 10%, due to a decrease in grid emissions. Therefore, the grid plays a larger role in supplying the minimum amount of electricity for the hot-standy state. The required battery size is thus 1.4 times smaller, resulting in a 2.4-times lower battery cost.

Compared to the 23 MW case, the 90 MW case has a lower cost for the electrolyzer and FT section due to economies of scale. As a comparison, the FT and electrolyzer conversion cost 2969, 2500, 2114, and 2055 EUR_{2019}/tonne SAF for the 23, 90, 540 and 900 MW cases, respectively. This represents a levelized cost decrease of more than 40% when scaling from 23 MW to 540 MW. At 90 MW, less battery storage is needed due to the overcapacity of onshore wind. The PV/Wind capacity ratio is 0.3 compared to over 2 in the 23 MW case.

3.1.3. 2050 scenarios

In the 270 MW case, offshore wind is fully replaced by onshore wind, reflecting the fact that onshore generation remains the lower-cost option even in future scenarios. On-site electricity generation remains attractive over consuming grid mix electricity. The costs of self-generated (based on 2050 projections) electricity are typically lower than the costs of using electricity from the grid (based on 2019–2024 price levels).

In the decentralized case, in 2050 (23 MW) there is a more prominent role for selling electricity compared to the centralized cases due to the battery/PV combination. In 2050, it results in the lowest levelized cost at about 2745 EUR_{2019}/tonne e-SAF. This is significantly lower than the centralized cases, which ranged from 3300 to 3500 EUR_{2019}/tonne e-SAF.

3.2. Cost improvements in future scenarios

3.2.1. 23 MW electrolyzer

Fig. 3 presents changes in the different cost category shares between 2025 and 2050 for the various cases. A relative comparison between the different scenarios and across the different cases is presented in Fig. 5, Appendix B. In the 23 MW scenario, the contribution of the battery decreases from just below 20% to less than 5% by 2050, and its capacity decreases from 115 to 40 MW. The electrolyzer cost is the category with the second-largest decrease in costs. The capacity remains the same, but the investment cost decrease by a factor four.

PV capacity decreases from 193 MW to 111 MW, resulting in a 67% decrease in the levelized cost of product compared to the 2025 scenario.

The FT synthesis shows a small 14% cost decrease compared to 2025 due to the assumptions on the increase in efficiency and the higher yield in syngas conversion.

The increase in cost is influenced by a change in the grid electricity consumption. More grid electricity can be consumed while fulfilling the RFNBO requirements, as the GWP of the grid decreases across the scenarios. Using grid electricity reduces the need for overcapacity, resulting in less excess energy that could be sold, this in turn, reduces the revenue from selling electricity. However, the electricity selling business model has a smaller role in future scenarios. Furthermore, the need for overcapacity also decreases due to enhanced operational flexibility, specifically the ability of the FT and electrolysis plants to operate at lower minimum loads in the 2050 scenario. This also reduces the temporary storage requirement from 72 tonnes in 2025 to 23 tonnes in 2050. The same is valid for the operation range in the hot boxes of the electrolyzer, which contributes to a decrease in the required battery capacity. Across the scenarios it was assumed that FT investment costs do not change over time, due to its high TRL level. Therefore, the FT section of the plant has a larger share of the total cost in a 2050 scenario compared to 2025. In contrast, the electricity share of the cost in 2050 is comparable to that in 2025. The main difference is that, by 2050, a larger cost fraction is expected from onshore wind electricity rather than PV.

3.2.2. 90 MW electrolyzer

In the 90 MW case, the model shows a decrease in the capacity of onshore wind by a factor larger than 3. Due to the increased flexibility in the FT section of the plant, the syngas storage capacity decreases from 514 tonnes in 2025 to 149 tonnes in 2050.

In the 2050 scenario, revenue from electricity sales decline, as the battery is utilized significantly more for internal consumption (28% of the year) than for grid injection (5% of the year).

3.2.3. 540 and 900 MW electrolyzer

The large cases of 540 and 900 MW have a comparable cost distribution and follow similar decrease and increase patterns as seen in Fig. 3. In the 540 MW case, a reduction of offshore wind capacity is observed from 2191 MW to 556 MW, resulting in a 77% reduction in cost of SAF. In the 900 MW case, the cost decrease is similar (75%), with the offshore capacity decreasing from 4132 MW to 1142 MW in 2050.

4. Discussion

4.1. Electrolyzer size limits

The electrolyzer size in the decentral cases are constrained by a low amount of CO_2 input per year (30 ktonne CO_2), which appears as a limiting factor for reaching larger electrolyzer capacities. The larger decentralized cases (e.g., 32 and 36 MW) were significantly oversized for the low hourly CO_2 input.

At electrolyzer scales below 90 MW, economies of scale in the electrolyzer were assumed. Although the specific unit investment cost decreased at larger scales, this benefit was outweighed by the low-capacity factor resulting from the limited CO_2 supply. The plant size in this study was bound by the specific CO_2 availability of the evaluated case. However, the results suggest that applying a decentralized concept (e.g., direct transmission lines, local demand for the end-products, and an electrolyzer co-located with the CO_2 source and FT synthesis) to a larger biogenic CO_2 point source would be promising. This approach would combine the integration benefits of the decentralized configuration with cost reductions from economies of scale.

In the centralized case, the lowest levelized cost cases were powered by PV and onshore wind. When the CO_2 is not a limiting factor, as a consequence of the input assumptions of the case, the maximum electrolyzer capacity capable of producing the lowest cost product was determined by the maximum capacities of both PV (193 MW) and onshore wind (567 MW). With a 90 MW electrolysis plant, both electricity sources were at the upper capacity limit allowed in the model. In order to scale the electrolyzer to larger sizes, the model needed to select offshore wind electricity, which did not have an upper constraint. In the model, offshore is replaced with onshore wind by 2050 due to projected cost reductions with a constant capacity limits across scenarios. In reality, however, increasingly restrictive spatial limitations will likely prevent this onshore expansion, maintaining the need for offshore wind for large-scale centralized configurations.To power a 90 MW electrolysis plant, the onshore wind power plant would require 189 turbines spread over 4200 ha of land (4.5 turbines of 3 MW per km^2 [37]). Furthermore, the PV plant would require 200 ha of land at 10 MW per km^2 [37]. In the 23 MW case, 193 MW of PV (200 ha) and 79 MW of onshore wind were required. This requires 27 turbines and 600 ha of land.

The spatial implications of these configurations differ significantly. Since the electrolysis plant in the decentralized case serves as the point of interconnection, grid fees are avoided but strict co-location requirements are imposed. Consequently, this assumption may underestimate eventual costs, as achieving such strict co-location is geographically difficult for large-scale PV and wind parks. Alternatively, where co-location is not feasible, additional costs arise either from dedicated off-grid transmission infrastructure or grid fees.

Securing such vast land area in the direct vicinity of the e-SAF becomes a major barrier in the land-constrained Netherlands. Therefore, the 23 MW configuration offers a clear advantage: its significantly smaller spatial footprint reduces permitting complexity and land acquisition hurdles. By being independent from large-scale CO_2 infrastructure, this configuration avoids the extensive development requirements of the centralized case, which could enable a faster implementation timeline.

4.2. Perspective on biogenic CO_2 availability

An e-SAF plant with a 90 MW electrolysis section consumes approximately 120 ktonne CO_2 and produces 31 ktonne of e-SAF per year at full load. In the Dutch context, CO_2 electrolysis shows the most potential when coupled with biogenic CO_2 sources ranging from 30 to 120 ktonne/year. In the Netherlands, only 2 biomethane and 2 pulp and paper plants fall within the 30 – 120 ktonne CO_2 size range. In Europe, approximately 10 biomethane, 15 bioethanol, and 25 pulp and paper plants fall within this range, see SI 8 [28]. In total, 3.6 Mtonne CO_2/year is available from these sources, with a 0.92 Mtonne annual e-SAF potential. This would be sufficient to meet the 2030 RFNBO ReFuelEU Aviation sub-target of 1.2% % of total fuel. This is calculated as approximately 0.70 Mtonne e-SAF/year from the RFNBO percentage in EU Regulation 2023/2405 and projected EU jet fuel demand (60 Mtonne kerosene/year) [38]. Note that this CO_2 quantity is insufficient to meet the 2035 ReFuelEU Aviation sub-target of 5% of total.

4.3. Biogenic CO_2 infrastructure constraints

Due to the RFNBO regulation, dedicated infrastructure for biogenic CO_2 must be developed. As a consequence, biogenic CO_2 used for RFNBO-compliant fuels will not directly benefit from the infrastructure being developed for CCS. Instead, a parallel system would need to be developed to avoid mixing fossil and biogenic CO_2 flows. The biogenic CO_2 supply chain will have a smaller scale and therefore higher unit cost. Alternatively, biogenic CO_2 can be utilized for negative emissions via CCS. While this presents a competing utilization pathway in regions developing CCS networks, the decentralized e-SAF configuration can be advantageous for isolated biogenic sources lacking access to centralized CO_2 transport infrastructure.

4.4. Cost comparison fossil kerosene and SAF

In our previous study [6], where unrestricted grid electricity could be used, syngas production costs were estimated at 1350 EUR_{2019}/tonne syngas. In the 2025 decentralized case (23 MW), the costs rise to 1650 EUR_{2019}/tonne syngas, and are projected to decline to 1150 EUR_{2019}/-tonne syngas by 2030. In 2030 at 23 MW, when syngas further converted to e-SAF as the end-product, the costs are projected at 4260 EUR_{2019}/tonne e-SAF. This is seven times more expensive than fossil kerosene at a price of 580 – 600 EUR_{2019}/tonne kerosene and more than 2.5 times the current prevailing price of SAF at 1630 – 2035 EUR_{2019}/tonne SAF [39,40]. In the 2050 scenario, the costs are projected approximately 35–70% higher than SAF at 2745 EUR_{2019}/tonne e-SAF. In other words, this production route will not be cost-competitive in future scenarios, effectively requiring a permanent price premium.

4.5. Limitations of the decentralized configuration

Beyond the need for a cost premium, the decentralized configuration faces two distinct implementation hurdles unique to the distributed nature and smaller scale of the design. First, a TRL gap exists between the proposed small-scale FT units and standard industrial facilities. While FT synthesis has traditionally relied on economies of scale [41] microchannel reactors have recently enabled efficient small-scale applications. Companies such as CompactGTL and INERATEC have developed modular FT designs that leverage process intensification to achieve high production rates within a compact footprint [42]. However, despite these innovations, the technology is still at a lower TRL than mature counterparts; consequently, the specific investment costs and deployment speeds remain subject to greater uncertainty.

Second, in this case study it was assumed that the naphtha fraction could be co-valorized (accounting for 10% of the total economic value). However, in remote decentralized locations, the logistical costs of transporting such small volumes to petrochemical hubs may prove economically prohibitive. This risks using the naphtha for lower-value internal heating applications which will increases the levelized cost of the e-SAF.

4.6. Limitations of study

In the current case study, grid electricity prices were based on historical data. However, in future scenarios, the price level and its fluctuations are uncertain. These price levels can fundamentally alter the system design as the economic balance would change. For instance, lower prices could decrease both production costs and sales revenues simultaneously. This might lead to a smaller financial incentive for self-sufficiency, with a heavier reliance on the grid and less investment in local generation. Higher prices,however, could trigger a tipping point at which investing in renewables combined with battery integration becomes optimal. The current model can be used to identify and evaluate such shifts. Therefore, future work should consider the uncertainty in the input profiles for energy generation and electricity prices to understand how the sizing decisions are affected by them.

This study contains an exploratory scenario analysis of centralized versus decentralized configurations. The evaluation of the long-term uncertainties of investment costs and low-readiness technologies falls outside the current scope. Future work should therefore consider more elaborate sensitivity analysis to identify the exact boundaries of our findings under uncertainty. Moreover, the current optimization model operates with perfect foresight. Therefore, the model is able to use the battery and storage to its fullest potential. In real-world operation, the lack of such foresight leads to sub-optimal performance. This can lead to a decline in electricity sales revenue and undersized storage estimates. In reality, larger overdesign factors are required to compensate for forecast errors and guarantee safe operation. To capture these real-world dynamics, future models could be extended by integrating an operational layer that optimizes the operation without relying on perfect foresight.

The e-SAF produced in this work complied with the RFNBO regulations, focusing exclusively on greenhouse gas emissions. However, this approach neglects broader enviromental impact categories. Furthermore, it does not include construction of infrastructure in the analysis. Including Life Cycle Assessment could help to determine the life cycle impacts of the centralized and decentralized configurations, allowing to evaluate them based on both economic and environmental criteria.

Finally, this estimate represents a lower cost bound, as it excludes the investment and operational costs for CO_2 purification steps required before electrolysis to remove upstream impurities [43].

4.7. Outlook

Previous work has highlighted the importance of grid emissions in centralized SAF production [6]. The current work explores an alternative for regions lacking CO_2 infrastructure or an RFNBO-compliant grid mix. In this system, energy generation, CO_2 sourcing, and conversion are co-located. Since the e-SAF volumes are smaller, the plant could be ideally located in the vicinity of a small airport for the offtake of SAF.

The direct transmission lines were exclusively evaluated for decentralized configurations based on the assumption that strict co-location requirements are largely incompatible with the massive electricity demands of a centralized plant. However, a key insight derived from the decentralized configurations is that direct or 'behind-the-meter' connections can provide significant cost benefits. Therefore, future work should also explore different connection strategies for centralized configurations.

The specific scale evaluated in this work represents a niche application relevant for small-scale regional European airports. The benefits from decentralized implementation evaluated in this work could also be applied to larger scale distributed biogenic CO_2 sources. As these sources are typically unsuitable to be integrated with centralized CO_2 infrastructure. Ultimately, given the tension between the bulk requirements of the aviation market and the scale limitations of decentralized production, this technology configuration may be better suited for high-value specialty products, where the premium production cost is more easily justified. A detailed market evaluation of specific high-value end-products was outside the core scope of this study; a targeted market and techno-economic analysis on these pathways is highly recommended for future work. Moreover, this implementation method cannot meet the bulk fuel demands of large airports. Consequently, the decentral design for CO_2E to produce e-SAF is primarily suitable as a stepping stone to enable technology scaling.

5. Conclusions

This work evaluated the economic performance of e-SAF production via CO_2 electrolysis and Fischer-Tropsch (FT) synthesis in the Netherlands. Specifically, the study compared large-scale centralized with small-scale decentralized configurations. Furthermore, the analysis quantified the impact of future scenarios on the optimal sizing of system elements.

In the short term (2025), the 90 MW centralized electrolysis plant or a decentralized electrolysis plant configuration of 23 MW appears the optimal electrolysis plant size with the lowest levelized cost of e-SAF (about 5,230 EUR_{2019}/tonne e-SAF). The 90 MW capacity needed a renewable electricity supply from onshore wind (567 MW) and photovoltaics (PV, 193 MW). The decentralized design required 79 MW of onshore wind with the same capacity of PV. In both designs selling electricity is an important aspect of the business case.

The conversion cost (electrolysis and FT synthesis) of the decentralized 23 MW design are more than 40% higher than the centralized 540 MW design. This cost increase was mitigated by the exclusive reliance on lower-cost onshore wind and PV, avoiding the more expensive offshore wind generation required for larger designs. A decentralized system of 23 MW offers three distinct benefits that can offset the loss of economies of scale. (i) Direct transmission lines from the renewable generation to the electrolysis plant eliminates grid fees, which reduces the total electricity costs; (ii) A large PV plant with battery integration enhances electricity sales, and (iii) co-location with a CO_2 source and FT synthesis decreases transport emissions in the supply chain. This enables a higher limit on the amount of grid electricity that can be consumed.

These attributes make decentralized designs particularly relevant in regions lacking centralized carbon capture and storage (CCS) infrastructure, and enable valorization of small-scale distributed biogenic CO_2 streams (<120 ktonne CO_2/ year). While the resulting e-SAF volumes cannot meet bulk aviation demand, the e-SAF output matches with the fuel demand of smaller airports.

Despite these advantages, e-SAF produced via CO_2 electrolysis remains more costly. In 2030, the production cost of 4,260 EUR_{2019}/tonne e-SAF is more than 2.5 times the current SAF price (1,630–2,035 EUR_{2019}/tonne). Even in 2050, a substantial premium remains needed, with projected costs of 2,750 EUR_{2019}/tonne e-SAF (approximately 35–70% higher than current SAF price).

The centralized and decentralized configuration results in comparable cost in the near term (2025), but the decentralized route outperforms the centralized configuration in long-term projections. However, even with projected future improvements, it still faces significant economic barriers. A fundamental mismatch remains between the high cost of small-scale production and the low margins of a bulk fuel with an enormous market demand. In this context, the technology may be better suited for high-value specialty products, where the price premium is more easily justified. To unlock the full potential for e-SAF, future work must identify locations where high-quality renewable generation resources geographically or a fully renewable grid mix overlap with distributed biogenic CO_2 streams.

Abbreviations

Abbreviation	Full Term
CAPEX	Capital expenditures
CCS	Carbon Capture and Storage
CO2	Carbon Dioxide
e-SAF	Electro-sustainable aviation fuel
FLH	Full load hours
FT	Fischer-Tropsch
GRQ	Groningen Airport Eelde
GWP	Global Warming Potential
LCA	Life Cycle Assessment
OPEX	Operational expenditures
PV	Photovoltaics
RFNBO	Renewable Fuels of Non-Biological Origin
SAF	Sustainable aviation fuel

CRediT authorship contribution statement

Andrea Ramírez: Writing – review & editing, Supervision, Methodology, Conceptualization. **Thijmen Wiltink:** Writing – original draft, Visualization, Investigation, Formal analysis, Data curation. **Mar Pérez-Fortes:** Writing – review & editing, Supervision, Project administration, Methodology, Funding acquisition, Conceptualization.

Declaration of Generative AI and AI-assisted technologies in the writing process

During the preparation of this work, Thijmen Wiltink used Microsoft Copilot and Grammarly to correct grammar and spelling and improve the style of writing. After using these tools, all authors reviewed and edited the content as needed and take full responsibility for the content of the published article.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. – Fuel demand decentralized case

The Groningen Airport Eelde (GRQ) is a regional airport in the northern Netherlands and serves as the e-SAF demand location for the case study. Its fuel consumption was estimated as no officially published data is available. In 2023, the airport served approximately 108,500 passengers [44]. The majority (92%) of traffic from the GRQ consists of charter flights to leisure destinations, with an estimated average flight distance of 2500 kilometers based on popular routes to Southern Europe [45]. Aviation fuel efficiency for short to medium-haul flights is estimated to be between 3 and 4 liters per 100 passenger-kilometers, which corresponds to approximately 0.025 kg of kerosene per passenger-kilometer [46]. Based on these metrics, the total estimated kerosene consumption for Groningen Airport Eelde in 2023 is approximately 6800 tonnes (108,500 passengers × 2500 km × 0.025 kg/pkm). This estimate is limited to commercial passenger traffic and excludes fuel consumption from other airport activities, such as flight training.

The scale and number of passengers of GRQ are highly representative of a broader niche market across Europe. According to Dziedzic et al. [47], out of a sample of 146 regional airports, 56 fall into the exact same category as GRQ, serving between 0 and 200,000 passengers annually. Furthermore, the traffic structure at airports of this size is also driven by short to medium-haul flights and low-cost leisure routes.

Appendix B. – Additional figures: absolute cost contribution decentralized case and relative cost contribution across different electrolyzer sizes

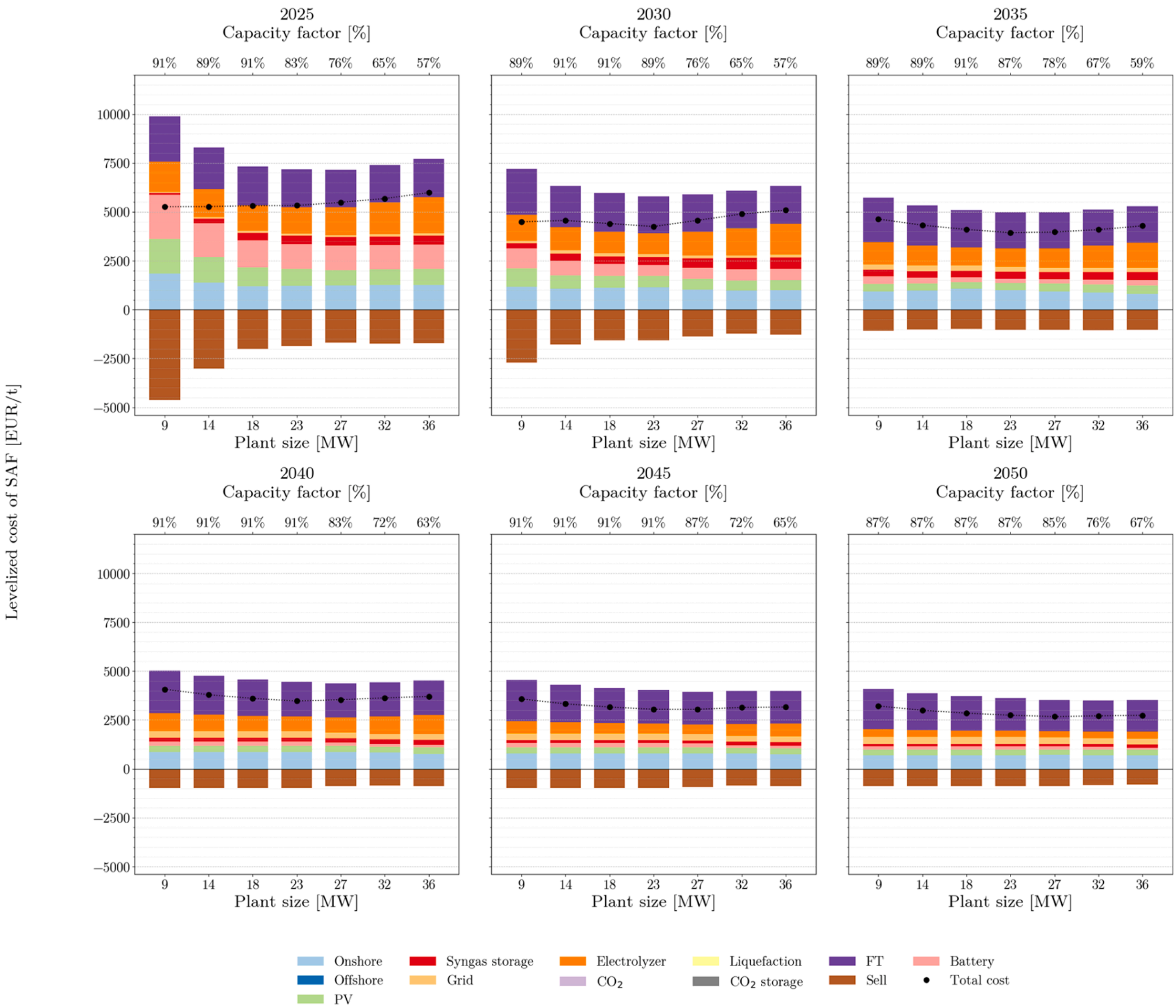

Fig. 4. Overview of the cost categories of different decentralized scenarios at different small scales.

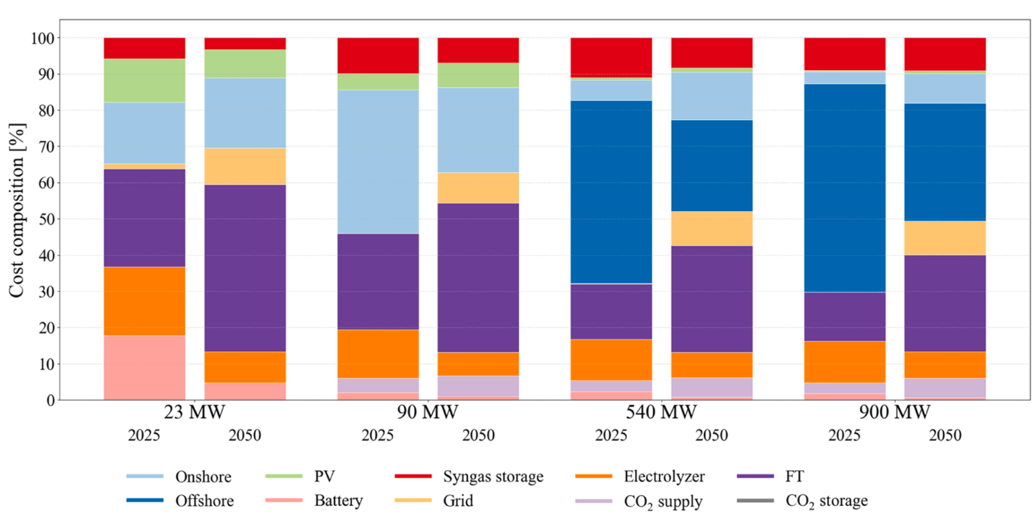

Fig. 5. Relative cost contribution of the 2025 and 2050 scenarios across different electrolyzer sizes.

Appendix C. – System improvements in future scenarios

In Table 1 an overview of the different cost categories for the 2025 and 2050 scenarios are presented. For the intermediate scenarios (2030–2045), please find the used values in SI 3.

Table 1
System improvements considered in the different scenarios with reference values for 2025 and 2050

#	Category	System element		Change	2025	2050	Unit	Source
1	Cost	RES	PV	CAPEX	34.6	21.8	[EUR_{2019}/kW/yr	Danish Energy Agency [19]
			Wind Onshore		92.7	81.0	[EUR_{2019}/kW/yr]	Danish Energy Agency [19]
			Wind Offshore		255.7	179.1	[EUR_{2019}/kW/yr]	Danish Energy Agency [19]
2	Cost	RES	PV	OPEX	-	-	[EUR_{2019}/MWh]	Danish Energy Agency [19]
			Wind Onshore		2.1	1.9	[EUR_{2019}/MWh]	Danish Energy Agency [19]
			Wind Offshore		4.6	2.9	[EUR_{2019}/MWh]	Danish Energy Agency [19]
3	Capacity factor	RES	PV	Capacity factor	0	7.2	[%]	Danish Energy Agency [19][1]
			Wind Onshore		0	8.6	[%]	Danish Energy Agency [19][1]
			Wind Offshore		0	5.7	%	Danish Energy Agency [19][1]
4	Cost	Battery		CAPEX	86.1	37.7	$MEUR_{2019}$/kW/yr	Danish Energy Agency [18]
5	Process yield	Battery		Discharge efficiency	98	98.5	%	Danish Energy Agency [18]
6	Process yield	Battery		Charge efficiency	98	98.5	%	Danish Energy Agency [18]
7	Process yield	FT		Carbon efficiency	94	97	%	Boilley et al. [22][2]
8	Operation bound	FT		Minimum operation threshold	70	50	%	Luo et al. [26][3]
9	Process yield	Electrolysis		Carbon efficiency	80	98	%	Danish Energy Agency [48]; Noordende et al. [27][4]
10	Process yield	Electrolysis		Electrical efficiency	10.2	10.0	MWh/tonne sygas	Danish Energy Agency [48]; Noordende et al. [27][5]
11	Cost	Electrolysis		CAPEX	2000	500	EUR_{2019}/kW	Detz et al. [49]; Wiltink et al. [50][6]
12	Operation bound	Electrolysis		Minimum operation threshold	70	32.5	%	Lorenz et al. [35]; Schwarze et al. [51][7]
13	Operation bound	Grid	Centralized	Maximum grid percentage	1.1	100	%/h	Calculated[8]
			Decentralized	Maximum grid percentage	21.1	100	%/h	Calculated[8]

[1] Percentual improvements to the capacity factor were based on the Danish Energy Agency [19] and applied to the used capacity factor profile of Renewable Ninjas [52].
[2] Derived from the CO_2 input and product (e-SAF) output.
[3] The minimum operation bound in the 2025 scenario was set at 70% based on Luo et al. [26], assumed to drop to 50% in 2050.
[4] Total carbon efficiencies of electrolysis and FT synthesis were based on the power-to-jet carbon efficiency of the Danish Energy Agency [48], which were used to calculate the separate electrolysis and FT synthesis carbon efficiency.
[5] The projected improvements over time from the Danish Energy Agency [48] was applied to the base efficiency of Noordende et al. [27].
[6] Starting CAPEX in 2025 was based on Wiltink et al. [50]. The cost in future scenarios were based on the 15% learning rate of Detz et al. [49]. For the assumptions regarding the cumulative installed capacity, see SI 4.
[7] Lorenz et al. [35], modeled individual hot-boxes that could operate as low as 80%. This lower bound was implemented in a 2025 scenario. Schwarze et al. [51] operated an electrolyzer at 32.5% of its capacity; therefore, this was set as the minimum bound of the electrolyzer operation in 2050.
[8] The same methodology was used as in previous work [6], see SI 1 and 2; the efficiency improvements were considered in calculating the maximum amount of grid mix electricity that can be consumed each hour. All scenarios assume that the infrastructure is built in 5 years. Therefore, the grid intensities 5 years after the starting date of the project are used. For the start dates 2025 and 2030, operational grid emissions were set to 205 and 138 kg CO_2-eq/MWh, respectively, based on projections provided in Adriaansens and Jetten [23]. For the 2035 scenario, the grid mix is assumed to reach the regulatory threshold at which the RFNBO renewable energy requirement is lifted (EC/2023/1184), i.e., 65 kg CO_2-eq/MWh. Finally, for the scenarios with timelines from 2040 onward, grid emissions are assumed to drop below 34.5 kg CO_2-eq/MWh, a level sufficiently low to allow the plant to operate entirely on grid electricity while remaining compliant.

Appendix D. – Centralized case biogenic CO_2 sourcing

The biogenic CO_2 supply chain for the centralized case was designed using a supply chain optimization tool from our previous work [28,50], adapted for Belgium and the Netherlands, see Fig. 6.

To comply with RFNBO regulations, only biogenic CO_2 from pulp, paper, and bioethanol facilities was included. The dedicated pipeline infrastructure was sized to continuously deliver up to 1.0 Mtonne of CO_2 per year at a constant cost of 75 EUR_{2019}/tonne CO_2. This cost is a result of the optimization model. Because the e-SAF plant is guaranteed an on-demand supply and can flexibly draw any required amount of CO_2 up to this 1.0 Mtonne limit. When the e-SAF plant is operating at partial load, CO_2 is sent via a satellite pipeline to the Porthos infrastructure for permanent offshore storage. In the centralized case, venting of CO_2 was not permitted.

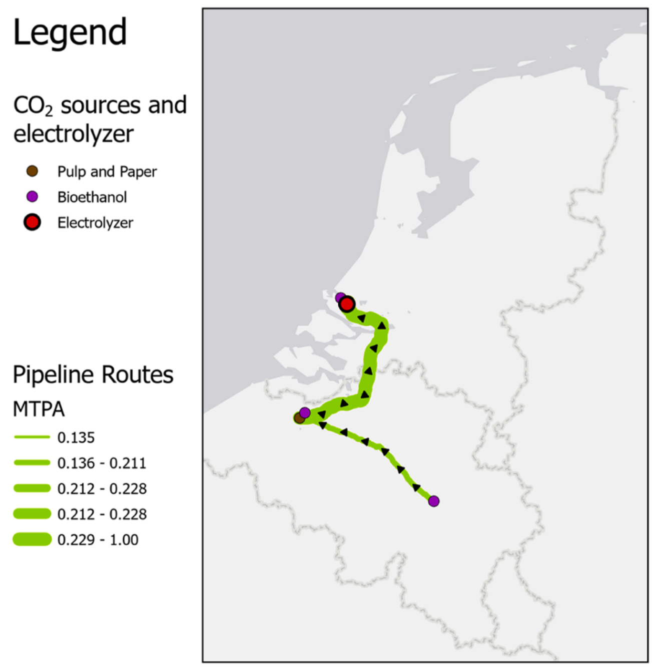

Fig. 6. Biogenic CO_2 supply chain and pipeline design for the centralized cases. MTPA: Mtonnes per annum.

Data availability

Supplementary material related to this article can be found online at: https://doi.org/10.5281/zenodo.17597046.

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