

The Cost of Sustainable Dispatchable Electricity Generation

Cost and performance assessment of
decarbonisation pathways for dispatchable power
generation

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Summary

This study evaluates the costs, operational characteristics and investment-recovery requirements of alternative pathways for decarbonising dispatchable electricity generation. The assessment compares hydrogen-fired gas turbines, Carbon Capture and Storage (CCS) equipped thermal generation, conventional biomass-fired generation, biomass-derived syngas configurations and Bioenergy with carbon capture and storage (BECCS) under assumed utilisation levels ranging from 500 to 3,500 annual full-load hours. These utilisation levels constitute a screening range rather than a forecast of plant-specific operating hours.

The results highlight a broader challenge: providing low-carbon dispatchable capacity under low-utilisation conditions is costly across the pathways assessed. When annual operating hours decline, fixed and other project-level costs must be recovered from a smaller volume of electricity production, increasing the levelised cost of energy (LCOE), particularly for capital-intensive technologies. Technologies with lower capital intensity are less sensitive to this effect, but may nevertheless face high generation costs where fuel costs and conversion losses dominate. The challenge therefore extends across hydrogen-, CCS- and biomass-based pathways, although its origin and magnitude differ between technologies.

The assessment identifies different techno-economic profiles rather than a single preferred pathway. Hydrogen-fired gas turbines combine comparatively low fixed-cost exposure at the generation-asset level with relatively high marginal generation costs. Open-cycle gas turbines (OCGTs) have particularly rapid start-up and ramping characteristics, while combined-cycle gas turbines (CCGTs) combine greater efficiency with somewhat longer start-up requirements. These operational characteristics arise primarily from the turbine and plant configuration rather than from the production origin of the hydrogen. Their lower capital intensity reduces the revenue required for fixed-cost recovery but does not offset the need for electricity prices high enough to cover hydrogen supply costs and conversion losses.

CCS-equipped thermal generation has greater fixed-cost-recovery requirements associated with the generating asset, capture installation and supporting CO₂ transport and storage chain. Capture-related efficiency losses and process-integration requirements also affect marginal costs and operational suitability. These pathways are therefore generally more sensitive to annual utilisation and cumulative operating margins. Conventional biomass, biomass-derived syngas and BECCS combine capital, feedstock and operational exposures in different proportions. BECCS may additionally provide carbon-removal value where sustainable biomass is used and captured biogenic CO₂ is permanently stored.

A central conclusion is that system-cost effective solutions are and not necessarily attractive options in terms of private investability. LCOE indicates the average cost of electricity production under an assumed utilisation level, while the system-cost assessment compares technologies under specified operating conditions. Neither determines whether an asset will realise those operating hours or earn sufficient revenues during those hours to recover its costs. Actual cost recovery depends on the interaction between realised dispatch, captured electricity prices, marginal generation costs, fixed-cost requirements and any additional revenue streams. A technology may therefore appear cost-effective at an assumed utilisation level while remaining difficult to finance if actual operating hours or captured margins are insufficient or uncertain.

Conversely, an investable technology does not necessarily provide the most cost-effective contribution to system objectives. Fuel-intensive technologies require electricity prices high enough to cover marginal generation costs whenever they operate, while capital-intensive technologies depend more strongly on sufficient cumulative margins to recover fixed and other project-level costs. Capacity or other availability-related revenues could reduce the share of fixed costs that must be recovered through electricity-market spreads but would not remove the need to cover marginal costs during operation.

The public value of the assessed pathways cannot be inferred from a single indicator. LCOE and CO₂ avoidance costs provide comparative technology-level cost information but do not represent integral electricity-system costs. Similarly, the Flexible Market Participation Efficiency indicator provides a comparative measure of operational suitability within the assumed activation window but does not measure system adequacy or firm-capacity contribution. Potential system roles must therefore be assessed by considering sustainability, affordability and reliability alongside private investability and the availability of supporting infrastructure and supply chains.

The assessment consequently points to potentially complementary techno-economic functions rather than a universal technology ranking. It does not establish that all pathways will be required or determine their appropriate scale. The identified system-role alignments should be interpreted as hypotheses rather than deployment recommendations. The second work package in this study will further assess these hypotheses through integrated power-system simulation, including dispatch patterns, captured electricity prices, adequacy contributions, system-wide emissions effects and investment recovery.

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Abbreviations

BECCS	Bioenergy with Carbon Capture and Storage
CAPEX	Capital Expenditures
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
ELCC	Effective Load Carrying Capability
ETN	European turbine Network
ETS	European Trading System
FMPE	Flexible Market Participation Efficiency
OCGT	Open Cycle Gas Turbine
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditures
LCOE	Levelized Cost of Electricity
LOLE	Loss of Load Expectation

1 Introduction

As the share of variable renewable generation increases, dispatchable generation is expected to operate under changing and potentially lower-utilisation conditions. A systematic and comparable understanding of the costs and operational performance of low-carbon dispatchable technologies is therefore increasingly important. Existing assessments often focus on average production costs or Levelised Cost of Energy (LCOE), while the potential contribution of dispatchable assets also depends on their ability to operate under different scarcity and system-stress conditions.

Technology comparisons based on a single cost or performance indicator may provide an incomplete basis for policy and investment decisions. Technologies differ not only in their total generation costs, but also in the distribution of costs between capital investment, fuel consumption and other operating requirements. They also differ in start-up behaviour, ramping capability, infrastructure dependence and the market revenues required to recover their costs. These characteristics affect their potential system roles and their performance as annual utilisation changes.

These questions have become more salient as the Dutch policy context has evolved. The 2023 Nationaal Plan Energiesysteem set out the direction towards a climate-neutral energy system and included the ambition of moving towards CO₂-free electricity generation by 2035. The Klimaat- en Energienota 2025 subsequently recognised that the complete phase-out of CO₂-emitting dispatchable generation by 2035 would involve significant technical, affordability and security-of-supply challenges. The government therefore continues to pursue the transition towards a CO₂-free electricity system while placing security of supply and affordability above complete emissions elimination in 2035.

Against this background, there is a need for a differentiated assessment of the pathways available for decarbonising dispatchable generation. In particular, insight is required into the interaction between cost structure, annual utilisation and operational requirements. This study therefore considers a range of assumed utilisation levels and operating conditions to compare how alternative pathways may perform. These assumptions provide a screening range and should not be interpreted as forecasts of plant-specific operating hours.

The study combines cost and operational indicators within a consistent comparative framework. From a system-cost perspective, screening-curve analysis, merit-order positioning, LCOE and CO₂ avoidance costs provide insight into technology costs and potential system roles under different utilisation assumptions. The Flexible Market Participation Efficiency indicator complements this analysis by comparing operational suitability within an assumed activation window. A separate investment perspective examines the electricity prices, dispatch spreads and cumulative revenues required for private cost recovery.

Together, these perspectives support a more transparent assessment of how low-carbon dispatchable generation pathways may contribute to a sustainable, affordable and reliable electricity system. The study does not determine the optimal technology mix or forecast future dispatch and market revenues. These system-level interactions will be examined through the power-system simulations undertaken in WP2.

2 Goal and Scope

2.1 Objectives

This study aims to improve understanding of the costs, operational characteristics and system value of low-carbon dispatchable generation technologies that may contribute to future electricity systems with high shares of renewable energy.

Existing assessments often focus on average generation costs or levelized cost metrics, while the value of dispatchable generation is increasingly determined by its ability to provide reliable capacity during periods of scarcity, low renewable output, and system stress. As a result, both economic performance and operational characteristics must be considered jointly.

2.2 Research Questions

This study therefore develops a consistent comparative framework for assessing alternative pathways for decarbonising dispatchable generation.

Overarching research question

How do the costs and operational characteristics of different pathways for decarbonising dispatchable generation compare when assessed within a consistent techno-economic and cost-abatement framework?

Interpretation and analytical perspective

The central research question was jointly defined by TNO and EZK as a broad comparative assessment of alternative pathways for decarbonising dispatchable generation. Addressing this question requires consideration of both system-level and investment-level perspectives.

From a system perspective, technologies contribute to the least-cost provision of dispatchable generation under different operating conditions and utilisation rates. From an investment perspective, technologies must also be capable of recovering their costs under the operating patterns expected in future low-carbon electricity systems.

The study addresses this overarching research question through the following analytical perspective:

How do different pathways for decarbonising dispatchable generation perform from both a system-cost and investment-recovery perspective, and how are these outcomes affected by utilisation rates and operational requirements?

To address this question, the study examines a sequence of interrelated issues. The analysis starts by assessing technology costs and cost structures under different utilisation rates and operating regimes. It then examines the operational roles for which different technologies are technically suited and how these roles influence expected utilisation levels. Subsequently, the study evaluates the implications for economic performance and cost recovery. Finally, the

implications for technology deployment during different stages of the transition are considered.

Underlying research questions

The study therefore addresses five related questions:

- 1. Cost structure and utilisation sensitivity**
How do differences in fixed and variable cost structures affect the economic performance of alternative decarbonisation pathways under changing utilisation rates?
- 2. System costs and cost-effectiveness**
How do costs, LCOE and CO₂ avoidance costs develop for different decarbonisation pathways under varying utilisation rates and operating regimes?
- 3. Operational role and technical suitability**
Which technology configurations are technically suited to different operational roles, including baseload, mid-merit, peak-load and flexibility services, considering characteristics such as start-up behaviour, ramping capability and operational responsiveness?
- 4. Investment recovery and economic viability**
To what extent can alternative pathways recover their costs under the utilisation levels and operating patterns expected in future low-carbon electricity systems?
- 5. Transition pathways**
Which characteristics determine the potential role of different technologies during different phases of the transition towards a low-carbon electricity system?

A central theme throughout the assessment is the interaction between utilisation rates, technology cost structures and investment recovery. As renewable penetration increases, dispatchable generation is expected to operate less frequently, making utilisation rates a critical determinant of both system costs and economic viability with increasing levels of variable renewable electricity sources.

The five underlying research questions that underpin the overarching research question can be grouped into two complementary analytical perspectives.

The first perspective focuses on the electricity system as a whole. From this system-cost perspective, the key questions are how different technologies contribute to decarbonisation, which operational roles they are suited for, and how their costs evolve under different utilisation rates. This perspective is reflected in indicators such as LCOE and CO₂ avoidance costs, which provide insight into the cost-effectiveness of alternative decarbonisation pathways.

The second perspective focuses on the ability of technologies to attract investment and deliver capacity in practice. From this investment perspective, the key question is whether technologies can recover their costs under the operating patterns expected in future low-carbon electricity systems. This perspective is reflected in indicators such as investment viability and required revenue recovery.

Together, these perspectives provide the basis for assessing whether alternative pathways can contribute to sustainable, affordable and reliable transition pathways, by considering both their system-cost effectiveness and their ability to attract investment and deliver dispatchable low-carbon capacity in practice.

2.3 Scope of the assessment

The assessment focuses on commercially deployable and industrially relevant scalable low-carbon thermal power generation systems that can realistically contribute to near- and medium-term electricity generation in alignment with energy transition objectives. Combined Heat and Power (CHP) and cogeneration systems were excluded because their operation is primarily driven by heat demand rather than electricity market conditions. Nuclear generation technologies were not included within the agreed project scope. Advanced geothermal systems (AGS/EGS) and large-scale fuel-cell power plants were excluded due to limited commercial deployment, uncertain scalability and a lack of large-scale operational experience.

Low-carbon thermal power systems may be characterised by their technology configuration, fuel pathway and carbon management approach.

1. Technology configurations
 - Open Cycle Gas Turbines (OCGT);
 - Combined Cycle Gas Turbines (CCGT);
 - Integrated Biomass Gasification Combined Cycle (IGCC) systems;
 - Ultra-Supercritical Steam Cycle (USC) systems.
2. Fuel pathways
 - natural gas;
 - steam-methane reforming hydrogen (grey hydrogen);
 - steam-methane reforming hydrogen with CCS (low-carbon hydrogen);
 - autothermal reforming hydrogen with CCS (blue hydrogen);
 - hydrogen from electrolysis (green hydrogen);
 - hydrogen from ammonia cracking;
 - biomass;
 - biomass-derived syngas.

Hydrogen blending was not included as a separate pathway because the resulting emission reductions remain limited relative to the required hydrogen volumes and associated infrastructure investments.¹

3. Carbon management
 - None
 - CCS (partial or full)
 - BECCS (ergo negative emissions)

The resulting low-carbon thermal power concepts assessed in this study are summarised in Table 1.

¹ Resulting CO₂ reduction remains modest compared to the amount of hydrogen required and substantial hydrogen blending requires significant upfront investments in infrastructure (transport, storage, and conversion).

Technology configuration	Fuel pathway	Carbon management	Assessed concept
OCGT	Hydrogen	None	H2 OCGT
CCGT	Hydrogen	None	H2 CCGT
CCGT	Reforming hydrogen	None	Grey H2 CCGT
CCGT	Reforming hydrogen	CCS	Low-carbon H2 CCGT
CCGT	Ammonia-derived hydrogen	None	H2 CCGT
CCGT	Biomass-derived hydrogen	None	H2 CCGT
IGCC	Biomass-derived syngas	None / CCS	IGCC
USC	Biomass	None	Biomass plant
USC	Biomass	CCS	BECCS

Table 1: Low-carbon thermal power concepts assessed in this study.

2.4 Technology Characterization

Dispatchable generation technologies can fulfil different roles within the power system. For the purpose of this study, technologies are classified based on their function in the power system, separating those used for:

- peak loads;
- mid-merit needs; and
- baseload generation.

These categories reflect differences in operational flexibility, efficiency, start-up characteristics and expected utilisation rates. Peaking technologies are primarily intended for short-duration operation during periods of scarcity, whereas mid-merit and baseload technologies typically operate for longer durations and may face technical or economic constraints that favour more continuous operation. In the following sections we briefly characterize the selected technologies.

2.4.1 Gas turbine technologies

Gas turbine technologies remain among the most flexible dispatchable generation options and are therefore evaluated in several configurations. Open Cycle Gas Turbines (OCGTs) are primarily suited for peaking and reserve capacity applications due to their rapid start-up capability, fast ramping performance, and operational simplicity, although they exhibit lower electrical efficiencies. Combined Cycle Gas Turbines (CCGTs), by contrast, recover waste heat through steam cycles and consequently achieve substantially higher efficiencies, making them more suitable for mid-merit (i.e. flexible baseload) applications.

2.4.2 Biomass-based power generation

Biomass-based power generation represents another important category of sustainable dispatchable power considered in this study. Biomass systems can utilize agricultural residues, forestry by-products, municipal organic waste, sewage sludge, or other biogenic feedstocks to generate electricity and heat. These technologies offer dispatchable operation characteristics comparable to conventional thermal generation while potentially reducing

lifecycle greenhouse gas emissions depending on feedstock sourcing and supply chain management. In addition, Bioenergy with Carbon Capture and Storage (BECCS) configurations are increasingly investigated because they combine renewable biomass conversion with CO₂ capture, potentially enabling net-negative emissions. BECCS is therefore considered a strategic long-term option in many net-zero scenarios, particularly for offsetting residual emissions from hard-to-abate industrial sectors.

2.4.3 Integrated Biomass Gasification Combined Cycle (IGCC) systems

These systems refer to integrated systems in which biomass is first converted into syngas that serves as a feedstock for the production of chemicals or fuels. Electricity generation is then a secondary function.

Under normal operating conditions, the syngas is directed towards the primary production process. During periods of power scarcity or high electricity prices, however, part of the syngas stream can be diverted to power generation, allowing the facility to provide dispatchable electricity to the grid. The flexibility therefore originates from the ability to switch the use of syngas between chemical production and electricity generation.

Thermal energy storage and synthetic fuel synthesis are complementary technologies that can be integrated within such industrial energy systems to enhance operational flexibility, but they are not the defining characteristics of the hybrid system itself.

This integrated strategy may become more prominent, as it supports the use of existing thermal generation infrastructure while complementing variable renewable electricity production. In this study, the production of green hydrogen, blue hydrogen, and syngas has been assessed, with particular attention given to syngas alongside synthetic fuel generation.

2.4.4 Carbon Management

Carbon Capture and Storage (CCS) systems are evaluated as a means of maintaining dispatchable thermal generation capacity while substantially reducing direct CO₂ emissions. CCS can be integrated with natural gas combined-cycle plants, industrial cogeneration facilities, waste-to-energy systems, and biomass conversion technologies. The captured CO₂ is transported for permanent geological sequestration or industrial utilisation. Although CCS introduces efficiency penalties, additional parasitic loads, and increased capital expenditures, it remains one of the few scalable options capable of providing firm low-carbon thermal generation using existing combustion-based infrastructure. As such, CCS-based systems are frequently considered transitional technologies supporting grid stability during periods of increasing renewable penetration. However, CCS-equipped plants are generally less flexible than conventional thermal generation assets. The integration of capture, compression, and CO₂ handling systems can reduce ramping performance, increase operational complexity, and make frequent start-stop operation less attractive from both a technical and economic perspective. As a result, CCS-based generation is typically better suited for applications with relatively stable operating profiles than to highly flexible peaking or balancing services.

3 Methodology

The economics of low-carbon dispatchable generation are determined by more than technology costs alone. As renewable penetration increases, declining utilisation rates, changing operating patterns and increasing requirements for flexibility become equally important determinants of economic performance. Technologies that appear attractive from a cost perspective may not necessarily be suited to future operating conditions, while technologies that perform well operationally may face challenges in recovering their costs.

The assessment framework developed in this study therefore links technology cost structures, operational characteristics and market outcomes within a single analytical framework. Screening-curve analysis is used to identify how different cost structures perform under changing utilisation rates. Merit-order analysis subsequently places these technologies within the operational context of the electricity market by indicating their relative dispatch position under different market conditions. Revenue-recovery and cash-flow analyses then assess the conditions under which market operation may generate sufficient revenues to support investment. Together, these analyses provide the basis for evaluating both system-cost effectiveness and investment viability of alternative pathways for decarbonising dispatchable generation.

Figure 1 summarises the analytical framework and its relation to the research questions addressed in this study, while Table 2 provides an overview of the research questions and their corresponding analytical chapters

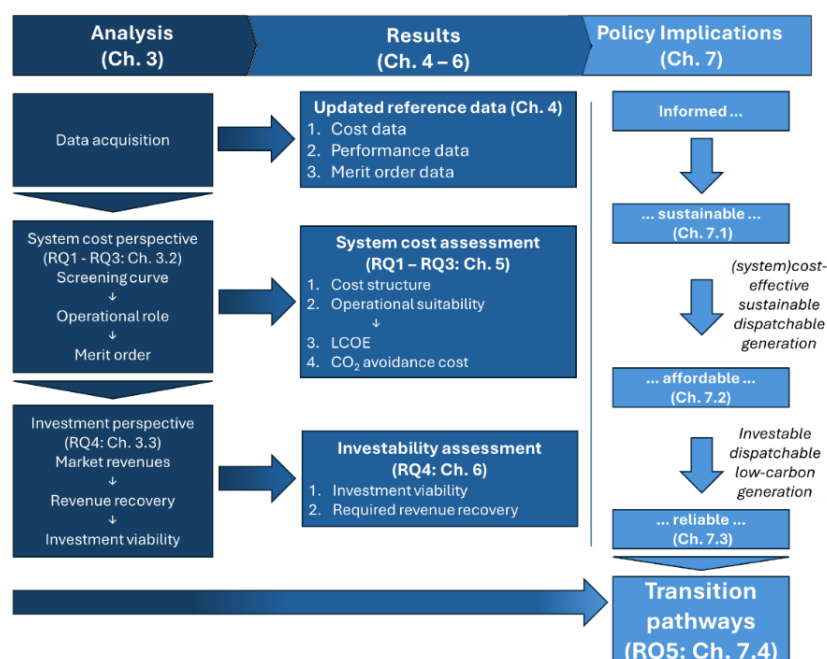


Figure 1: Conceptual framework linking system-cost effectiveness, investment viability and policy objectives for low-carbon dispatchable generation.

Table 2: Overview of research questions and corresponding chapters

Research question	Objective	Chapters
RQ1–RQ3	Assess system-cost effectiveness through cost structure, operational suitability, LCOE and CO ₂ avoidance costs	Chapters 4–5
RQ4	Assess investment viability through revenue recovery and cash-flow analysis	Chapter 6
RQ5	Assess implications for sustainability, investability, reliability and transition pathways	Chapter 7

3.1 Data Sources

Cost and performance data were compiled from public literature, industry reports, technology databases and expert consultations. Public sources include the U.S. Energy Information Administration (EIA), Gas Turbine World, Lazard, ETN publications and other publicly available techno-economic studies. These sources were supplemented with expert consultations involving technology suppliers, plant operators and technology institutes.

3.1.1 Cost data

The US government's EIA offers detailed electricity production cost breakdowns [4], which have been compared with other analyses, such as the Gas Turbine World handbook [1] or the Lazard LCOE study [7]. The dataset includes both capital expenditure (CAPEX) and operational expenditure (OPEX), with OPEX disaggregated into fixed and variable components. Fixed OPEX covers costs that are largely independent of plant operation, while variable OPEX reflects costs directly linked to generation output and operational dynamics.

For gas turbine technologies in particular, variable costs extend beyond fuel consumption and include operational processes such as start-up, shutdown, ramp-up, and ramp-down. These transient operating modes impose additional mechanical and thermal stress on key components, most notably turbine blades, leading to accelerated wear and more frequent maintenance or replacement cycles.

While increased operational flexibility enhances a plant's ability to respond to market signals, it also introduces higher maintenance intensity and associated costs. Accurately capturing these effects requires a detailed, case-specific assessment of operational profiles and cycling behaviour. However, given the scope of this study, a generalized variable cost component has been applied to represent these effects in a consistent and comparable manner across technologies.

3.1.2 Performance data

Performance data have been compiled and cross-validated using multiple publicly available and industry-relevant sources. In particular, the U.S. Energy Information Administration (EIA) [4, 5], provides a robust baseline for conventional generation technologies, including performance parameters such as efficiency, availability, and operational characteristics. For hydrogen-based gas turbine applications, more recent and technology-specific insights have been incorporated from studies published [18] by the European Turbine Network, which

reflect ongoing developments in hydrogen combustion, material constraints, and operational performance. Key technical performance parameters have been systematically reviewed and compiled into a structured dataset. These include cold and hot start times, ramp-up and ramp-down rates, thermal efficiency (or heat rates), and typical plant capacities.

These parameters are critical for assessing the operational flexibility and real-world dispatchability of each technology, as they directly influence the ability of assets to respond to short-term market signals and participate effectively in periods of system scarcity. Start-up characteristics determine how quickly a unit can become available from different operational states, while ramp rates define the speed at which output can be adjusted once online. Efficiency and heat rates are key drivers of fuel consumption and marginal cost, and typical plant size influences both system integration and scalability.

The collected data have been consolidated into a comparative table to ensure consistency across technologies, cost performance, and overall system value. By combining established reference data with emerging technology assessments, the study ensures a balanced representation of both mature and developing dispatchable generation options, while maintaining consistency in the comparative analysis.

3.1.3 Merit-order dataset

The merit-order dataset is based on the Dutch portfolio of dispatchable power plants is based on publicly available data from TenneT, national energy statistics, publicly disclosed information from power plant operators, and TNO's internal technology databases. The dataset includes existing and announced dispatchable generation assets and contains information on installed capacity, fuel type, technology configuration, operational status, and expected future developments..

3.1.4 Expert Consultation

To validate recent developments in gas turbine and carbon capture technologies, discussions were held with OEMs, operators and technology institutes during the ETN conference of March 2026. Participants included Baker Hughes, Siemens Energy, Ansaldo Energia, RWE, Equinor, Vattenfall and Uniper. In addition, ETN Global presented its study *Urgency and Positioning of Gas Turbines in Future Power Systems*, which provided additional context for operational assumptions regarding future gas turbine deployment and cycling behaviour. These consultations were used to validate assumptions regarding technology performance, operational flexibility and future deployment characteristics.

3.2 System-cost perspective

The system-cost perspective combines utilisation scenarios, screening-curve analysis, operational performance assessment and merit-order analysis to evaluate the cost-effectiveness of alternative decarbonisation pathways. Together, these analyses provide the basis for system-cost assessment through indicators such as LCOE and CO₂ avoidance costs.

3.2.1 Utilisation scenarios and dispatch assumptions

The analysis is conducted across multiple utilisation scenarios, defined by annual full-load hours ranging from 500 to 3500 full-load hours, with 2,000 hours used as an indicative central value. In the Netherlands, combined wind and solar output typically falls to low levels for around 2,000 hours per year. The wider range captures different potential operating regimes as well as year-to-year variation in wind and solar generation. These scenarios represent different potential operating regimes, ranging from low-utilisation assets providing backup during periods of low renewable generation or high residual demand to assets operating for a larger part of the year.

A minimum activation window of 10 hours is assumed to reflect typical dispatch conditions in short-term electricity markets with high levels of wind and solar. The 10-hour activation window was selected to represent typical dispatch durations for thermal dispatchable generation assets operating in energy markets and to allow comparison across technologies with different start-up characteristics. It is not intended to represent balancing services operating on timescales of seconds or minutes.

This approach enables the evaluation of how utilisation influences cost competitiveness and technology suitability. For transparency, all assets are dispatched under a common idealised dispatch assumption, reflecting a hot standby mode to support these operations. Limitations due to start-up and ramp-up speed are covered by a separate approximation step (see also 3.2.3).

3.2.2 Screening-curve analysis

From a system-cost perspective, the least-cost combination of generation technologies for a given load-duration curve can be approximated using the classical screening-curve methodology. The screening-curve framework provides an intuitive way of understanding the relationship between cost structure, utilisation rate and system role.

Figure 2 illustrates this relationship between cost structure and utilisation rate using this method. Technologies like USC with high fixed costs and relatively low marginal costs are more cost-effective at high annual utilisation rates. Technologies like CCGT with low fixed costs and relatively high marginal costs are more cost-effective at lower annual utilisation rates.

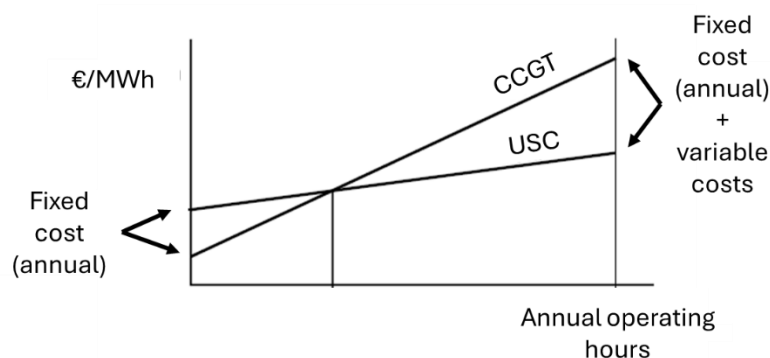


Figure 2: Illustration of annual cost versus annual utilisation rate. Adapted from (Stoft, 2002).

The next step in the screening-curve analysis illustrates the system role of these technologies in terms of peak, mid-merit and baseload assets. As above, the upper part of Figure 3 illustrates least-cost deployment of technologies with different combinations of annualised fixed costs and variable generation costs. The lower part of Figure 3 links these economically attractive operating hours to the load-duration curve of the electricity system. Technologies with the lowest costs at low annual utilisation occupy the peaking segment of the least-cost portfolio. Technologies requiring a large number of operating hours are positioned towards mid-merit or baseload operation. By structuring the asset base in this way, the analysis enables a comparison of technology cost structures and their potential roles in a least-cost generation portfolio

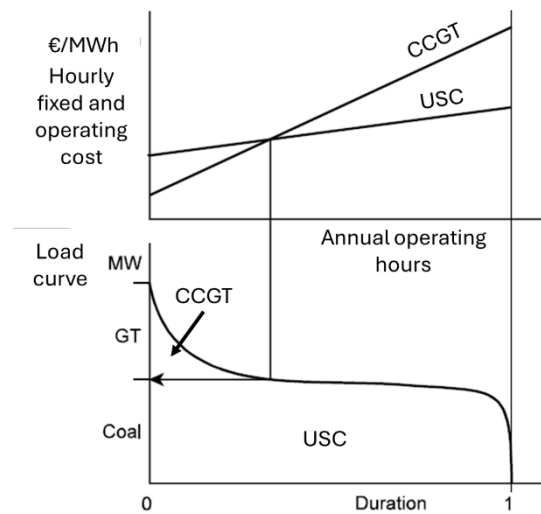


Figure 3: Conceptual screening curve framework linking cost structure, utilisation rate and system role. Adapted from (Stoft, 2002).

All technologies in this report are evaluated using low, mid, and high cost scenarios to reflect uncertainties in future hydrogen production methods, CCS cost developments, and market trends for both blue and green hydrogen. These scenarios are critical for understanding the sensitivity of results and the potential variability in long-term system costs.

3.2.3 Operational Performance and Dispatchability

In practice, however, operational constraints may prevent power assets from fully utilising all operating hours identified as economically attractive from a least-system-cost perspective. Operational constraints such as start-up times, ramp-rate limitations, thermal inertia and process stabilisation requirements may prevent a technology from fully capturing available market opportunities. To assess whether technologies can deliver effectively within the assumed activation window, this study complements the screening-curve analysis with the Flexible Market Participation Efficiency (FMPE) indicator.

We define the FMPE as the ratio of effective full-load operating time to the total activation window, considering the impact of hot start ramp-up times on the ability of a plant to respond to short-term market signals. FMPE is used as a comparative indicator of operational suitability and flexibility performance rather than a direct measure of economic performance. It provides a structured way to compare the ability of technologies to respond to changing operating conditions. Technologies with faster ramp-up characteristics achieve higher FMPE values and are therefore better suited for peak-load operation. However, FMPE should not be interpreted as a substitute for detailed dispatch modelling or power-system simulation.

FMPE captures operational flexibility differences between technologies designed for flexible operation and technologies designed primarily for high utilisation. Gas turbines achieve the highest FMPE values and are therefore well suited to peak-load operation and repeated cycling. CCS-equipped thermal generation and BECCS pathways, on the other hand, exhibit

lower FMPE values, indicating that operational constraints reduce their ability to capture short-duration dispatch opportunities. This distinction is further explored in the results section when analysing the interaction between cost structure, utilisation rate and system role.

FMPE can be interpreted as an operational correction to the cost-based screening framework, reflecting the extent to which potential electricity production can be delivered within the assumed activation window. It thereby links technology cost structure and operational performance to the potential fulfilment of a particular system role.

3.2.4 Merit Order Analysis

Whereas the screening-curve framework compares annual fixed and variable costs to identify potential roles in a least-cost portfolio, merit-order analysis ranks available generation according to short-run marginal generation costs for a particular dispatch interval. Together, these perspectives provide complementary insights into the operational role of dispatchable generation technologies.

Figure 4 illustrates this relationship by positioning dispatchable generation technologies according to their marginal generation costs. Subject to availability and operational constraints, technologies with lower short-run marginal costs are dispatched before technologies with higher short-run marginal costs. The point at which additional generation is required depends on residual demand: electricity demand after accounting for variable renewable generation and other non-dispatchable supply. Technologies with higher marginal costs therefore tend to operate during intervals of high residual demand rather than necessarily during intervals of high total demand.

Accordingly, technologies with lower marginal costs tend to occupy positions earlier in the merit order, while higher-marginal-cost units are more likely to operate in cycling or peaking regimes. The assets in Figure 4 are grouped into functional categories based on their cost position and operational characteristics. This operational classification complements the potential system roles identified through the screening-curve analysis; the two classifications do not necessarily coincide.

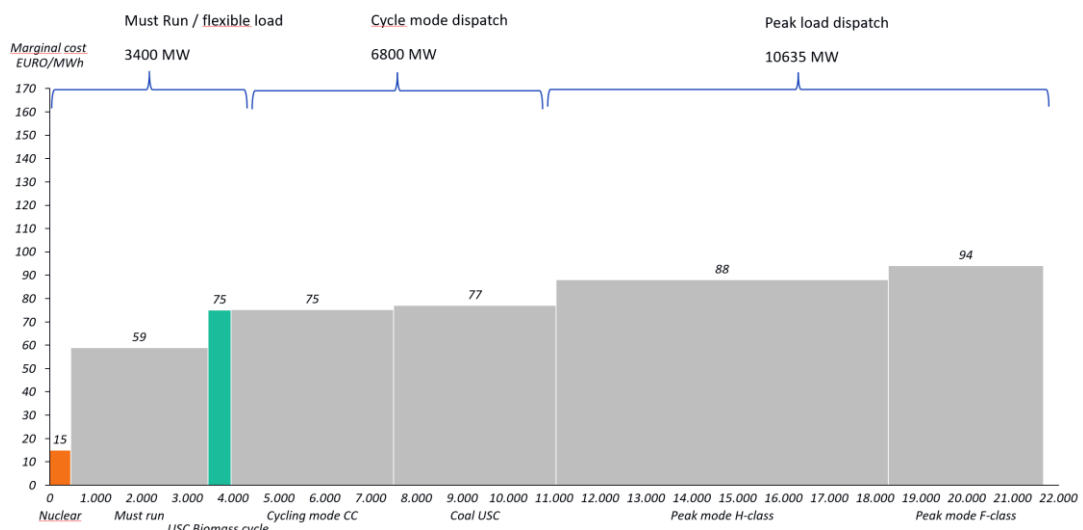


Figure 4: Illustrative merit order of Dutch dispatchable generation technologies, distinguishing between baseload, cycling and peaking operating regimes.

By structuring the asset base in this way, the analysis enables a comparison of relative dispatch position and short-run cost competitiveness for a specific dispatch interval. The merit-order framework also represents the fundamental price formation mechanism of competitive electricity markets and provides insight into which technologies are likely to be dispatched under different market conditions and which technologies are expected to set marginal electricity prices. Both current and future illustrative scenarios are considered, with and without ETS costs, to capture the impact of carbon pricing on competitiveness.

Whereas the screening-curve framework identifies the utilisation ranges over which technologies may contribute to a least-cost portfolio, the merit-order analysis indicates their relative dispatch position under the assumed fuel and carbon prices. It therefore helps identify the market conditions under which technologies may operate and earn an operating margin. As the study does not simulate hourly market clearing, the merit order does not determine plant-specific operating hours or revenues. These are examined conditionally in the subsequent investment analysis.

3.2.5 System-cost assessment

The preceding analyses establish the relationship between utilisation rate, cost structure, operational role and market positioning. Together, these factors determine the overall cost-effectiveness of alternative pathways for decarbonising dispatchable generation. To compare technologies from a system-cost perspective, two complementary indicators are applied throughout this study: the Levelised Cost of Energy (LCOE) and the CO₂ avoidance cost.

LCOE provides a measure of the average cost of electricity generation over the lifetime of an asset and captures the interaction between capital costs, operating costs and utilisation rates. The LCOE incorporates capital expenditure, fixed and variable operating and maintenance costs, fuel costs and, where applicable, carbon costs under the EU Emissions Trading System. CO₂ avoidance costs complement this perspective by dividing the additional cost of each low-carbon technology relative to a conventional natural-gas-fired reference plant by the corresponding reduction in CO₂ emissions.

Together, these indicators provide insight into the system-cost effectiveness of alternative decarbonisation pathways and form the basis for the comparative assessment presented in the results section. While LCOE and CO₂ avoidance costs provide insight into the cost-effectiveness of alternative pathways from a system perspective, they do not indicate whether these technologies can recover their costs under future operating conditions. This complementary question is addressed in the investment perspective developed in the following section.

3.3 Investment perspective

The system-cost perspective developed in the previous sections provides insight into the cost-effectiveness of alternative pathways for decarbonising dispatchable generation. However, technologies that appear attractive from a system-cost perspective are not necessarily capable of recovering their costs under future market conditions.

As renewable penetration increases, dispatchable generation is expected to operate less frequently and for shorter periods. Under these conditions, investment decisions become

increasingly dependent not only on technology costs, but also on the ability to generate sufficient revenues during the limited periods in which assets are dispatched.

The investment perspective therefore addresses the complementary question of whether technologies can recover their capital and operating costs under the assumed utilisation levels and market conditions considered in this study. This assessment is based on three successive steps. First, dispatch-spread analysis evaluates the operating margins that technologies may earn under different market conditions. Second, revenue-recovery analysis assesses whether these operating margins, together with any other revenues, are sufficient to recover the remaining fixed-cost requirement. Finally, cash-flow analysis evaluates whether the resulting revenue streams are sufficient to support investment over the lifetime of the asset.

Together, these analyses clarify the distinction between system-cost-effective and investable technologies and identify the conditions under which alternative pathways may contribute to sustainable, affordable and reliable transition pathways in practice.

3.3.1 Market revenues and dispatch spreads

The system-cost perspective identifies potential system roles and the merit-order analysis indicates the relative market position of dispatchable generation technologies. Whether these technologies are investable depends on the revenues they can earn when operating and, where applicable, on revenues for making capacity or other services available.

Energy-market revenues depend on the frequency and volume of dispatch and on the electricity prices realised during those periods. Technologies towards the peaking end of the merit order generally operate less frequently and therefore require higher margins during their operating hours to contribute sufficiently to fixed-cost recovery. Technologies occupying mid-merit positions can spread their fixed-cost requirements over a larger volume of generation, provided that their operating margins remain positive.

For dispatchable generation technologies, the contribution of electricity-market operation to cost recovery is commonly evaluated through dispatch spreads. In its simplest form, the spark spread can be expressed as:

$$\text{Spark Spread} = P_{\text{electricity}} - (P_{\text{gas}}/\eta_e)$$

where $P_{\text{electricity}}$ is the electricity price, P_{gas} the fuel price and η_e the conversion efficiency of the generating asset.

This simple spark spread represents the margin remaining after fuel costs. Other avoidable costs, including variable operating and maintenance costs, start-up costs and applicable carbon costs, must also be covered before a contribution is available for fixed-cost recovery.

The dispatch spread required to support investment is therefore not determined by fuel costs alone, but also by the underlying fixed-cost structure of the technology. Technologies with high fixed-cost exposure require a larger annual contribution from operating margins or other revenues. Technologies with lower fixed-cost requirements need a smaller contribution for fixed-cost recovery, although high fuel or other variable costs may limit the hours in which they can operate profitably.

The realised dispatch spread is the operating margin earned during the hours in which the asset is dispatched. The required dispatch spread is the average operating margin needed, given the assumed operating hours and other revenues, to recover the remaining fixed-cost requirement and support investment.

The required dispatch spread is evaluated by relating technology-specific cost structures to assumed operating hours and relative market positioning. As a result, dispatch spread requirements differ substantially between technology pathways and provide an important indicator of the conditions under which investment can be sustained.

3.3.2 Revenue recovery assessment

Revenue-recovery analysis aggregates the operating margins earned under the assumed operating conditions and assesses whether these, together with any other revenues, are sufficient to cover the annual fixed-cost requirement. This distinguishes the decision to operate in an individual period from the ability to recover costs over a year: a plant may operate profitably whenever dispatched while still earning insufficient annual revenue to support investment.

Simplified cash-flow analyses were performed for representative dispatchable generation pathways. These combine investment expenditure, fixed and variable operating costs, fuel costs, assumed utilisation and electricity-market revenues over the lifetime of the asset.

The calculations assume that the modelled electricity output can be sold at the electricity prices specified in each case. They do not simulate hourly market clearing, bidding behaviour, curtailment or all technical and contractual restrictions affecting realised revenues. The resulting calculations therefore provide indicative comparative benchmarks rather than bankable project evaluations.

The analyses evaluate the interaction between capital expenditures, fuel costs, operational efficiency, utilisation rates and electricity market revenues. Particular attention is given to the distinction between pathways characterised by high capital intensity and relatively low marginal operating costs, versus pathways characterised by lower capital requirements and higher fuel-related costs.

The resulting cash-flow analyses provide insight into the sensitivity of different technology pathways to declining utilisation rates and changing market conditions. The outcomes are subsequently used to assess investment viability and to identify the conditions under which alternative pathways can recover their costs.

3.3.3 Investment viability assessment

The distinction between system-cost-effective technologies and investable technologies becomes increasingly important in electricity systems characterized by high renewable penetration and declining utilisation rates for dispatchable generation.

Technologies with relatively low capital intensity, such as hydrogen-capable gas turbines, are generally less dependent on high annual utilisation rates for fixed-cost recovery. Conversely, highly capital-intensive technologies, including CCS-equipped thermal generation and

BECCS, depend more on stable operating conditions, higher capacity factors and sufficient revenue streams to recover their investments.

Biomass-based pathways and IGCC systems may occupy an intermediate position, depending on their combination of investment costs, fuel costs, operational characteristics and fixed-cost-recovery requirements. They may therefore be less exposed to declining operating hours than some capital-intensive CCS pathways, while generally requiring more sustained operation than low-capital, highly flexible generation.

As a result, technologies that perform favourably from a system-cost perspective do not necessarily perform favourably from an investment perspective. The ability to recover capital costs under future operating conditions therefore becomes an important determinant of technology deployment.

The investment viability assessment therefore synthesises the interaction between cost structure, utilisation rate, market revenues and revenue recovery requirements. Together, these factors provide insight into the conditions under which alternative technology pathways may contribute to sustainable, affordable and reliable transition pathways.

3.4 Limitations and uncertainties

The analytical framework developed in this study should be interpreted as a comparative techno-economic screening framework. While screening-curve analysis, merit-order analysis, FMPE assessment and revenue-recovery analysis provide insight into the relative performance of alternative pathways, they do not fully capture the dynamic interactions between dispatchable generation, renewable variability, market operation and system adequacy. Quantifying these interactions requires detailed power-system simulations, including dispatch optimisation, revenue formation, adequacy assessment and investment-recovery analysis under realistic market and system conditions. These aspects fall outside the scope of the present study.

4 Updated reference data

This section presents the consolidated techno-economic input data used throughout the assessment and benchmarking of the different energy conversion and generation technologies included in this study. The table provides a transparent overview of the key assumptions related to capital expenditure (CAPEX), operational expenditure (OPEX), emissions, and technical performance parameters.

The primary objective of this overview is to ensure full traceability and consistency of the assumptions used in the analysis. All major reference sources, supplier quotations, literature references, benchmarking studies, and calculation assumptions are documented and listed in the accompanying Excel file. The Excel workbook serves as the main data repository and supporting database for this report.

The cost structure has been organized into several main categories, including:

- Total CAPEX excluding connection costs
- Core equipment CAPEX
- Balance-of-System (BOS) costs
- Carbon capture related costs
- EPC/developer costs
- Contingency and miscellaneous costs
- Interconnection costs
- Decommissioning costs

In addition, the operational and technical performance assumptions have been structured in a transparent and standardized manner to facilitate comparison between technologies and scenarios. The operational data includes both fixed and variable OPEX assumptions, while the performance section captures key technical indicators such as:

- Rated capacity
- Electrical efficiency
- Heat rate
- Ramp-up and ramp-down capabilities
- Turndown ratios
- Annual degradation factors
- System lifetime
- Emission factors

Where applicable, the assumptions have been normalized on a €/kW, €/MWh, or emission-intensity basis to allow consistent benchmarking across the evaluated systems.

The accompanying Excel file should therefore be considered an integral part of this report, providing detailed calculation structures, source references, and supporting data for all operational cost and performance assumptions presented herein.

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5 System-cost assessment

The preceding methodological framework established the relationship between cost structure, utilisation rate, operational suitability and market positioning. This chapter applies that framework to assess the system-cost performance of alternative pathways for decarbonising dispatchable generation.

The analysis starts by examining the underlying cost structures of the assessed technologies and their sensitivity to declining utilisation rates. It subsequently evaluates how these characteristics influence economic performance through indicators such as LCOE and CO₂ avoidance costs, while also considering the operational roles for which different technologies are best suited. Together, these analyses provide the basis for assessing the system-cost effectiveness of alternative dispatchable low-carbon generation pathways.

5.1 Cost structure and utilisation sensitivity

This section applies the screening-curve framework qualitatively by comparing the fixed- and variable-cost structures of the assessed technology pathways and examining how these structures affect their relative cost position as utilisation declines. The screening-curve framework demonstrates that the economics of dispatchable generation are fundamentally determined by the interaction between cost structure and utilisation rate. The technologies assessed differ not only in their total costs, but also in the underlying cost structure. Some technologies are characterised by high fuel costs and relatively low capital expenditure, whereas others rely on low marginal costs but require substantial upfront investment. Understanding these differences is essential for assessing how technologies perform under declining utilisation rates and increasingly flexible operating regimes.

5.1.1 Fuel costs

Hydrogen supply costs are examined in greater detail than those of other fuels because the assessment includes multiple hydrogen production pathways, each resulting in different fuel-cost and emissions assumptions for power generation. The hydrogen production cost assessment presented in the previous chapter provides a comparative evaluation of multiple hydrogen production pathways and associated storage concepts under future market conditions. The production pathways are assessed here only insofar as they determine the fuel-cost and emissions inputs for hydrogen-based dispatchable generation. Fuel costs dominate the economics of hydrogen-based dispatchable generation pathways and explain a substantial part of the variation in marginal generation costs observed across technologies.

The analysis combines marginal production costs, operational expenditures, capital expenditures, feedstock costs, conversion efficiencies, and infrastructure-related charges to establish an indicative cost framework for hydrogen supply in future low-carbon energy systems. The assessment focuses on commercially relevant technologies, including electrolysis, gasification, steam methane reforming (SMR), autothermal reforming (ATR), and CCS-integrated hydrogen production pathways.

Table 4: Hydrogen production costs under the mid-case commodity-price assumptions.

		(Syngas) Gasification	(Hydrogen) Gasification + CCS	(Hydrogen) Gray Hydrogen	(Hydrogen) Blue Hydrogen	(Hydrogen) Ammonia cracker	(Hydrogen) Electrolyse
marginal	euro / MWh (Th)	30,0	148,1	44,9	101,1	128,2	183,3
opex	euro / MWh (Th)	16	26	5	10	5	40
capex	euro / MWh (Th)	25	42	8	14	8	64
gird	euro / MWh (Th)	0	6	6	6	6	6
total	euro / MWh (Th)	71	222	64	131	147	293
	euro / kg	n.a.	6,7	1,9	4,0	4,5	8,9
Biomass Price	euro / MWh (Th)	24	24				
Wind/solar energy prices	euro / MWh (e)						75
NG Price	euro / MWh (th)			35	35		
Ammonia Price	euro / MWh (th)					100	
Electricity grid costs	euro / MW (e)						35
CO2 tranport cost	euro / t		30		30		
CO2 intermediate storage costs	euro / t		20		20		
CO2 Storage	euro / t		55		55		
Capex	euro / kw	2122	3515	670	1200	670	3050
OPEX	%	5	5	5	5	5	3,8
Hydrogen stroage needs	%	0%	20%	10%	10%	10%	100%
Hydrogen storage opex	EURO/MWh	0	0,6	0,3	0,3	0,3	3
Hydrogen storage Capex	EURO/MWh	0	1,665	0,8325	0,8325	0,8325	8,325
Hydrogen net tarief	EURO/MWh	0	6,0	6,0	6,0	6,0	6,0
Running hours	hour	8400	8400	8400	8400	8400	4800
Pay back	years	10	10	10	10	10	10
Typical size	MW	200	200	400	400	400	200
Production per year	MWh (th)	1344000	1344000	2620800	2419200	2620800	576000
Efficiency	%	80%	80%	78%	72%	78%	60%

The overview results demonstrate substantial cost differences between hydrogen production technologies, primarily driven by feedstock prices, electricity demand, capital intensity, and carbon management requirements, as illustrated in Table 4. Grey hydrogen production cost is included only as reference.²

Conventional grey hydrogen production based on natural gas reforming remains among the lowest-cost pathways, with total hydrogen production costs estimated around 64 €/MWh(th), corresponding to approximately 1.9 €/kg H₂ under medium natural gas price assumptions. The relatively low cost position of grey hydrogen reflects the technological maturity of SMR processes, high conversion efficiencies, and comparatively moderate capital requirements.

Biomass gasification pathways exhibit a broader cost range depending on system configuration and CCS integration. Conventional gasification systems produce hydrogen at intermediate cost levels, while gasification combined with CCS reaches considerably higher production costs due to process complexity, feedstock handling requirements, gas cleaning systems, and carbon capture integration. The analysis indicates that gasification with CCS can exceed 220 €/MWh(th), equivalent to approximately 6.7 €/kg H₂. Nevertheless, biomass-based hydrogen production with CCS remains strategically important because it may achieve net-negative emissions, thereby providing both low-carbon energy and carbon removal potential.

Electrolysis-based hydrogen production represents the highest-cost pathway within the assessment under the assumed market conditions. Total production costs are estimated near 293 €/MWh(th), corresponding to approximately 8.9 €/kg H₂. The dominant cost drivers are electricity consumption and electrolyser capital costs. The workbook assumes electrolyser efficiencies around 65%, corresponding to approximately 56 kWh/kg H₂, which is broadly

² Grey hydrogen is included solely as a reference case. Hydrogen production through unabated natural-gas reforming introduces additional conversion losses and significant upstream CO₂ emissions. It is therefore not considered a decarbonisation pathway for dispatchable power generation.

consistent with current alkaline water electrolysis (AWE) and proton exchange membrane (PEM) technologies.

The electrolysis assessment further distinguishes between alkaline water electrolysis (AWE) and PEM technologies for 2025. AWE systems exhibit lower capital expenditures, approximately 1,500 €/kW, whereas PEM systems demonstrate higher investment costs ranging from approximately 1,800 to over 3,000 €/kW depending on the source and technology maturity assumptions. PEM systems, however, generally offer superior dynamic response capability and operational flexibility, making them particularly suitable for integration with intermittent renewable electricity generation.

Hydrogen storage infrastructure represents an additional cost component for hydrogen-based generation pathways. Storage costs vary depending on the storage concept and utilisation profile, but large-scale underground storage in salt caverns is generally considered the most cost-effective option for seasonal and long-duration applications. Infrastructure requirements therefore extend beyond the generating asset itself and form an important part of the overall hydrogen value chain. The importance of storage infrastructure is illustrated by the HyStock project in the Netherlands (see Text Box), which is currently the leading national initiative for large-scale underground hydrogen storage and is designed to connect directly to the Dutch and European Hydrogen Backbone networks.

An important outcome of the overall assessment is that hydrogen production economics remain highly sensitive to feedstock and electricity price assumptions. The hydrogen production-cost assessment includes low, medium and high price scenarios for natural gas and ammonia, demonstrating that future hydrogen competitiveness will strongly depend on energy commodity markets, carbon pricing mechanisms, renewable electricity availability, and infrastructure development. In particular, electrolysis pathways remain highly exposed to electricity price volatility, whereas reforming-based pathways are primarily influenced by natural gas market dynamics and carbon management costs.

Example: HyStock hydrogen storage project (Netherlands)

Hydrogen storage infrastructure is crucial for flexible hydrogen-based power generation. Salt cavern storage is the most cost-effective large-scale option, with cyclic storage costs at about 0.25 €/kg H₂ (8 €/MWh) [36], while less optimized methods cost up to 0.79 €/kg H₂ (26 €/MWh). Storage strategy and utilisation rates significantly impact final hydrogen costs, especially for seasonal or long-duration energy needs. HyStock [37], a project in the Netherlands, is developing underground hydrogen storage in salt caverns. The project will build an oversized plant with four caverns, able to store 25.3 kt (960 GWh) of hydrogen, an above-ground facility, and connections to the national and European Hydrogen Backbone networks. Technical specifications include:

- Maximum injection/withdrawal rate: 64 GWh/day
- Working gas volume: 1,000 GWh
- Underground capacity: 420 mcm (4 caverns totaling ~4,000,000 m³ at P_{max} 180 bar)

By linking HyStock to the Dutch, Belgian, and German hydrogen grids, the project aims to boost flexibility in the electricity system and provide services for the hydrogen value chain by 2030.

Overall, the analysis demonstrates that no single hydrogen production pathway universally dominates all evaluation criteria. Instead, future hydrogen systems are likely to involve a portfolio of complementary technologies serving different market functions. Biomass gasification and BECCS-related pathways may provide additional strategic value through negative emissions potential, despite their comparatively high production costs and greater process complexity.

5.1.2 Capital intensity and fixed-cost exposure

Whereas hydrogen-based pathways are characterised by high fuel costs and comparatively low fixed-cost exposure, CCS-based pathways are primarily characterised by high fixed-cost exposure. The relatively high fixed-cost exposure of CCS-equipped generation increases its sensitivity to declining utilisation, as fixed costs are allocated across a smaller volume of electricity production.

Hydrogen-based dispatchable generation exhibits a different cost structure. While hydrogen-fuelled gas turbines generally have higher marginal generation costs due to fuel production, conversion, transport, and storage costs, these systems typically require substantially lower upfront capital investment than CCS-equipped plants. In many cases, hydrogen-capable turbines can be developed as adaptations of existing gas turbine technologies and infrastructure. As a result, their total generation costs are generally less sensitive to declining utilisation rates, although they remain strongly influenced by hydrogen fuel costs.

5.1.3 Carbon management costs

Carbon management introduces both fixed and variable cost components. Capture installations require substantial upfront investment, while CO₂ separation, compression, transport and permanent storage also increase operational costs and energy demand.

Blue hydrogen pathways, incorporating CCS into reforming processes, demonstrate substantially higher production costs. The addition of carbon capture systems increases both capital expenditures and operational energy demand due to CO₂ separation, compression, transport, and storage requirements. As a result, blue hydrogen costs rise to approximately 131 €/MWh(th), equivalent to roughly 4 €/kg H₂ in the base case, with an upward bound of approximately €5/kg H₂. Under the assumptions applied, blue hydrogen provides a lower-cost low-carbon hydrogen supply pathway than electrolysis-based hydrogen, while retaining significant exposure to natural-gas prices and carbon-management costs.

The SMR and ATR assessment further illustrates the economic impact of carbon capture integration. Conventional SMR systems exhibit relatively low capital costs around 546 €/kW, whereas CCS-equipped SMR systems increase toward approximately 1,000 €/kW. Similarly, ATR systems increase from approximately 689 €/kW without CCS to approximately 1,200 €/kW with CCS integration. Capture rates between 90% and 96% significantly reduce CO₂ emissions but materially increase system complexity and capital intensity.

5.1.4 Synthesis of cost structures

Taken together, the technologies assessed can broadly be divided into fuel-intensive and capital-intensive pathways. Hydrogen-based generation is characterised by relatively high

fuel costs and comparatively low capital intensity, whereas CCS-equipped thermal generation exhibits the opposite profile. Biomass and IGCC pathways occupy intermediate positions. These differences in cost structure are expected to become increasingly important as operating hours decline and dispatchable assets are used more selectively.

The differing cost structures described in the previous subsections become increasingly important as annual operating hours decline. While fuel-intensive and capital-intensive pathways may exhibit similar costs under certain operating conditions, their economic performance can diverge significantly as utilisation rates decrease. The subsequent sections examine how these differences affect marginal-cost positioning, operational suitability, LCOE and CO₂ avoidance costs as utilisation declines.

5.2 Merit-order position

Figure 5 presents the illustrative merit-order position of the assessed dispatchable generation technologies under the mid-price assumptions used in this study. The ranking is based on marginal generation costs, including fuel costs adjusted for conversion efficiency, variable operating costs and, where applicable, carbon costs. Fixed investment costs are not included in the merit-order ranking. The figure excludes variable renewable generation and should therefore be interpreted as a comparison among dispatchable technologies rather than as a representation of the complete Dutch electricity market in 2040.

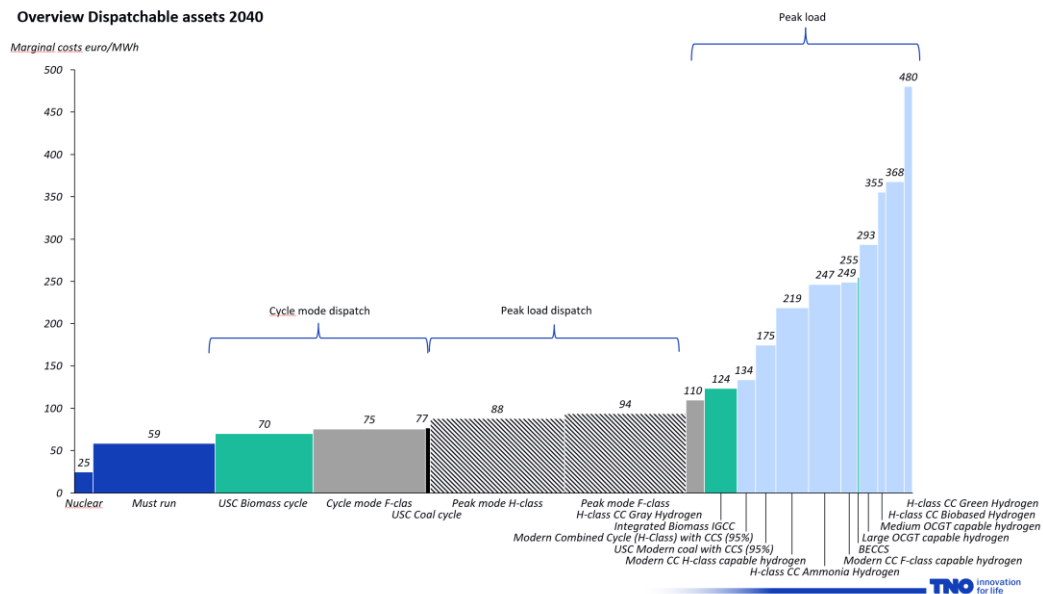


Figure 5: Illustrative merit-order position of dispatchable generation technologies under the mid-price assumptions used in this study (variable renewable generation excluded).

Reference technologies such as nuclear and conventional fossil-based generation are included to provide context for the low-carbon pathways assessed. Nuclear generation occupies the lower end of the ranking, with marginal costs of approximately 25 €/MWh.³ Conventional thermal generation follows at approximately 59 €/MWh.

³ This position reflects relatively low fuel and variable operating costs and does not imply that nuclear generation has the lowest total generation costs or is system-cost-effective under the utilisation conditions considered in this study.

Biomass-based USC generation and several conventional gas-fired configurations occupy the lower and middle parts of the dispatchable merit order, with marginal costs of approximately 70–94 €/MWh under the assumed input prices. CCS-equipped generation, IGCC configurations and hydrogen-compatible combined-cycle technologies generally occupy higher positions, reflecting combinations of fuel costs, conversion losses, variable operating costs and, where applicable, residual carbon costs. Hydrogen- and ammonia-based pathways exhibit the highest marginal generation costs in the assessment, ranging from approximately 219 to 500 €/MWh, primarily because of the assumed delivered fuel costs and associated conversion losses. BECCS also occupies a relatively high position on the basis of its marginal generation costs; the potential value of negative emissions is considered separately and is not reflected in the merit-order ranking.

The merit order provides an indication of the relative market position of technologies under the assumed input prices. It does not determine plant-specific operating hours, technical suitability for cycling, realised electricity-market revenues or investment viability. Operational suitability is assessed through the FMPE analysis in the following section, while revenue recovery and investment viability are considered in Chapter 6.

5.3 Operational suitability and FMPE

Operational performance is assessed using a range of technical characteristics, including start-up behaviour, ramping capability, operational flexibility, thermal inertia and suitability for cycling operation. Together, these characteristics determine the ability of technologies to respond to changing operating conditions and participate in flexibility-oriented electricity markets.

To facilitate comparison across technologies, the implications of start-up and ramp-up behaviour are summarised using the Flexible Market Participation Efficiency (FMPE) indicator, supplemented by an assessment of suitability for repeated cycling. FMPE should be interpreted as a comparative measure of operational suitability rather than as a direct measure of economic performance. Detailed dispatch behaviour and market participation ultimately depend on system-specific operating conditions and require dedicated dispatch modelling.

The FMPE indicator reflects the share of the assumed activation window during which a generation asset can effectively produce electricity, taking account of start-up and ramp-up requirements from hot standby. The final column of Table 5 provides an additional indicative assessment of suitability for repeated daily peak-load operation, considering standby requirements and cycling capability. Table 5 presents the assessed FMPE values of the evaluated dispatchable generation technologies under an assumed activation window of 10 hours.

The results show a clear distinction between technologies designed for rapid and flexible operation and thermal technologies with greater start-up requirements, thermal inertia or process-integration constraints. Hydrogen-capable OCGTs achieve the highest FMPE values, at approximately 98%, reflecting their rapid start-up capability and low thermal inertia. They are therefore technically well suited to short-duration and repeated peak-load operation within the assumed activation window.

Table 5: Flexible Market Participation Efficiency under an assumed activation window of 10 hours

		FMPE % Hot standby	Daily Peak from hot standby feasible
1	Medium OCGT capable hydrogen	98	✓
2	Large OCGT capable hydrogen	98	✓
3	Modern CC H-class capable hydrogen	93	✓
4	Modern CC F-class capable hydrogen	93	✓
5	USC Biomass cycle	60	✗
6	BECCS	40	✗
7	USC Modern coal with CCS (95%)	74	✗
8	Modern Combined Cycle (H-Class) with CCS (95%)	80	✗
9	Integrated Biomass IGCC	90	✓
10	H-class CC Green Hydrogen	93	✓
11	H-class CC Biobased Hydrogen	91	✓
12	H-class CC Ammonia Hydrogen	91	✓
13	H-class CC Gray Hydrogen	93	✓

Modern hydrogen-capable combined-cycle plants achieve FMPE values of approximately 91–93%. Although their steam-cycle integration results in slower start-up than OCGTs, they retain relatively strong operational responsiveness and may be suited to both mid-merit and longer peak-support operation. The small differences shown between hydrogen supply pathways do not result from the colour or production origin of the hydrogen itself. They reflect differences in the associated turbine configurations and the start-up and ramp-up assumptions applied to the respective cases.

IGCC configurations achieve FMPE values of approximately 90%, indicating relatively strong operational suitability compared with conventional biomass steam cycles. Conventional USC biomass and BECCS achieve lower values of approximately 60% and 40%, respectively, primarily because of their thermal inertia, slower start-up behaviour and greater process-integration requirements.

CCS-equipped coal- and gas-fired plants achieve FMPE values of approximately 74–80%. Although these technologies can operate flexibly, the integration of carbon-capture equipment introduces additional start-up and stabilisation requirements. Within the assumed activation window, these configurations are therefore less suited to repeated short-duration operation than OCGTs, modern combined-cycle turbines and IGCC systems. Figure 6 illustrates how start-up conditions affect the effective operating time of a USC plant equipped with CCS. The longer start-up and stabilisation requirements reduce the share of the activation window during which electricity can be delivered, particularly from a cold start.

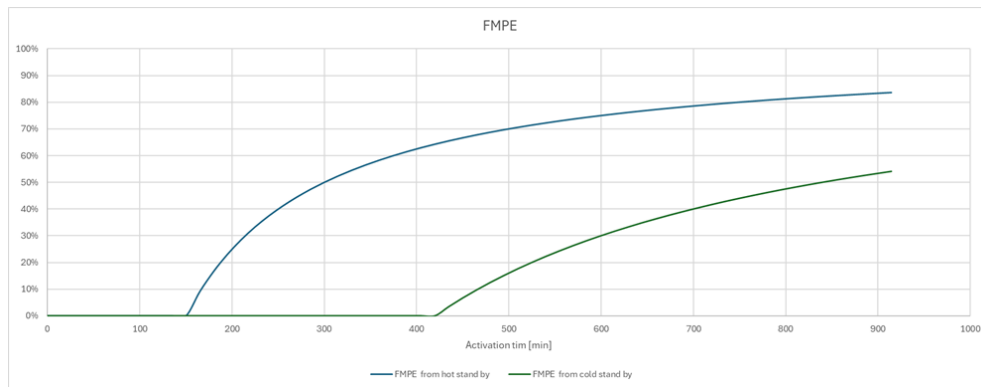


Figure 6: FMPE profile of a USC plant equipped with CCS following hot and cold starts.

Overall, the FMPE assessment marks operational flexibility differences between technologies optimised for rapid response and technologies optimised for more sustained operation. This operational classification complements the potential system roles identified through the screening-curve and merit-order analyses, as the classifications do not necessarily coincide. It does not predict plant-specific dispatch, participation in balancing markets or annual operating hours.

5.4 LCOE and CO₂ avoidance costs

The preceding sections assessed the potential system roles, relative market position and operational suitability of the evaluated technologies. This section examines how these characteristics translate into generation costs and CO₂ avoidance costs. It first considers how utilisation and operational conditions affect costs and subsequently compares the assessed technologies at two illustrative annual utilisation levels.

5.4.1 Utilisation sensitivity under different operational conditions

Annual utilisation affects cost performance by determining the volume of electricity across which fixed and other project-level costs are allocated. This effect is particularly pronounced for capital-intensive technologies. For fuel-intensive technologies, cost performance is generally less sensitive to fixed-cost allocation but more strongly influenced by fuel costs and conversion efficiency.

The cost effect also depends on the operating conditions under which the assumed utilisation is achieved. Under idealised conditions, annual full-load hours can be treated as fully delivered electricity production. In practice, start-up, ramp-up, part-load operation and process-stabilisation requirements may reduce the effective output delivered within individual activation windows.

FMPE provides an indicative measure of this operational effect. Technologies with rapid start-up and ramping characteristics retain a relatively large share of productive time within the assumed activation window. Technologies with longer start-up times, greater thermal inertia or more complex process integration may convert a smaller share of nominal activation time into effective full-load production. Where this reduces the electricity delivered under a given

operating profile, costs are allocated across less output, increasing LCOE and potentially CO₂ avoidance costs.

Figure 7 and Figure 8 illustrate this sensitivity for a modern combined-cycle plant equipped with CCS under idealised and FMPE-adjusted operating conditions. The CCS case is used as an illustration because its capture process introduces additional start-up, stabilisation and process-integration requirements. The same mechanism applies to other technologies, although its magnitude depends on their respective start-up, ramping and part-load characteristics.

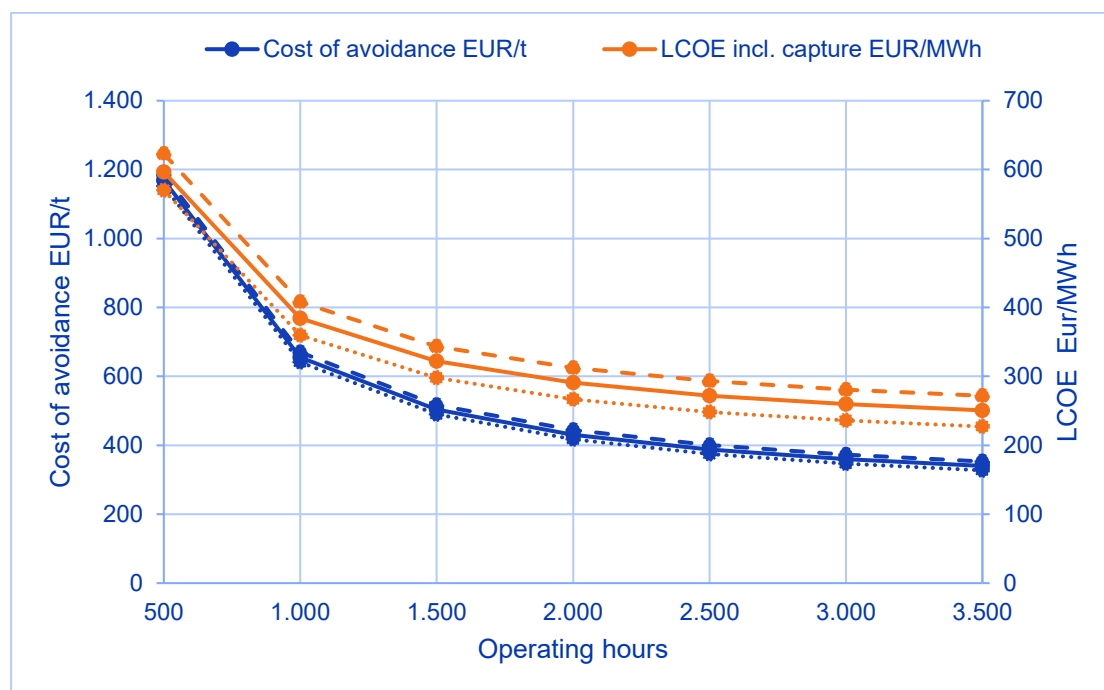


Figure 7: LCOE and CO₂ avoidance costs of a modern combined-cycle plant equipped with CCS under idealised operating conditions.

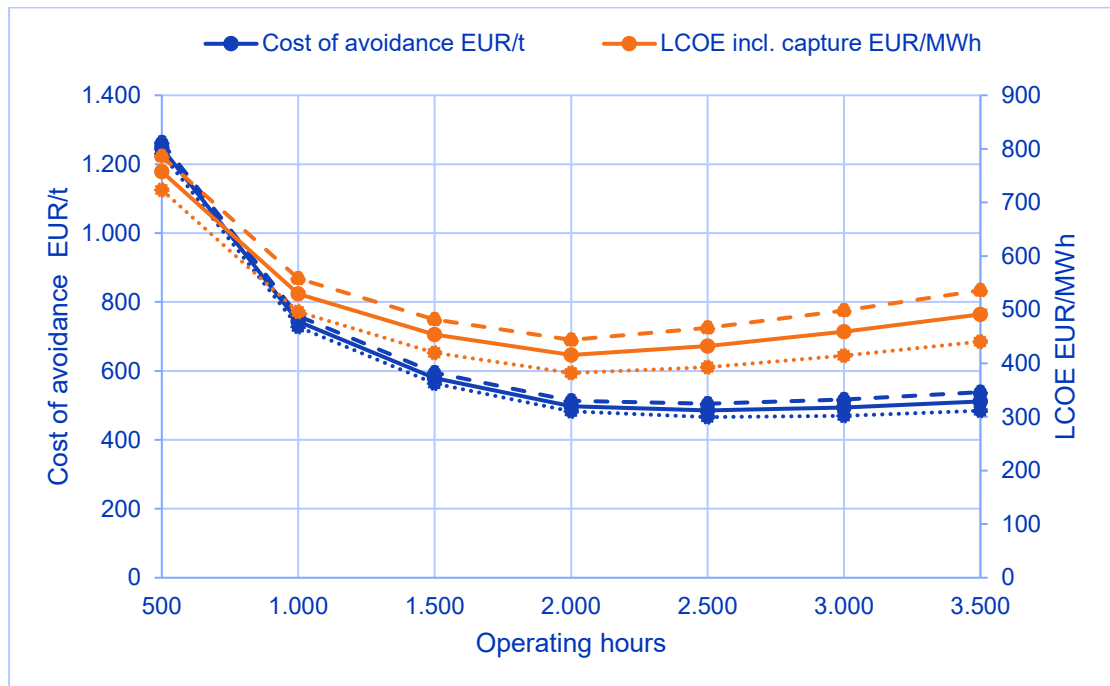


Figure 8: LCOE and CO₂ avoidance costs of a modern combined-cycle plant equipped with CCS under FMPE-adjusted operating conditions.

Higher annual utilisation does not mechanically result in lower FMPE. However, achieving additional operating hours may involve a broader mix of activation durations, start conditions and part-load operation. The cost consequences therefore depend on the composition of dispatch as well as on total annual full-load hours. The present assessment represents a stylised operational sensitivity and does not determine the actual distribution of future dispatch conditions.

5.4.2 Comparison across technologies

The LCOE and CO₂ avoidance-cost assessment compares the cost performance of the evaluated dispatchable generation technologies across assumed annual utilisation levels ranging from 500 to 3,500 full-load hours. Figure 9 and Figure 10 present marginal generation costs, LCOE and CO₂ avoidance costs at 1,000 and 2,000 full-load hours under the mid-price assumptions.

Comparison of Figures 7 and 8 shows how the cost structure of each technology affects its sensitivity to utilisation. Technologies with relatively high fixed costs generally show a stronger decline in LCOE as annual full-load hours increase, because these costs are allocated across a larger volume of electricity production. Technologies with lower fixed-cost exposure are less sensitive to utilisation, although their LCOE may remain high where fuel costs dominate.

At the assessed utilisation levels, hydrogen-capable gas turbines exhibit a trade-off between capital intensity and conversion efficiency. OCGTs benefit from relatively low capital costs but consume more hydrogen per unit of electricity produced because of their lower conversion efficiency. Combined-cycle configurations require greater capital investment but benefit from

substantially higher efficiency. Consequently, the relative LCOE position of OCGT and CCGT configurations depends on the balance between capital costs, hydrogen supply costs and assumed annual utilisation. Low capital intensity does not by itself result in the lowest LCOE.

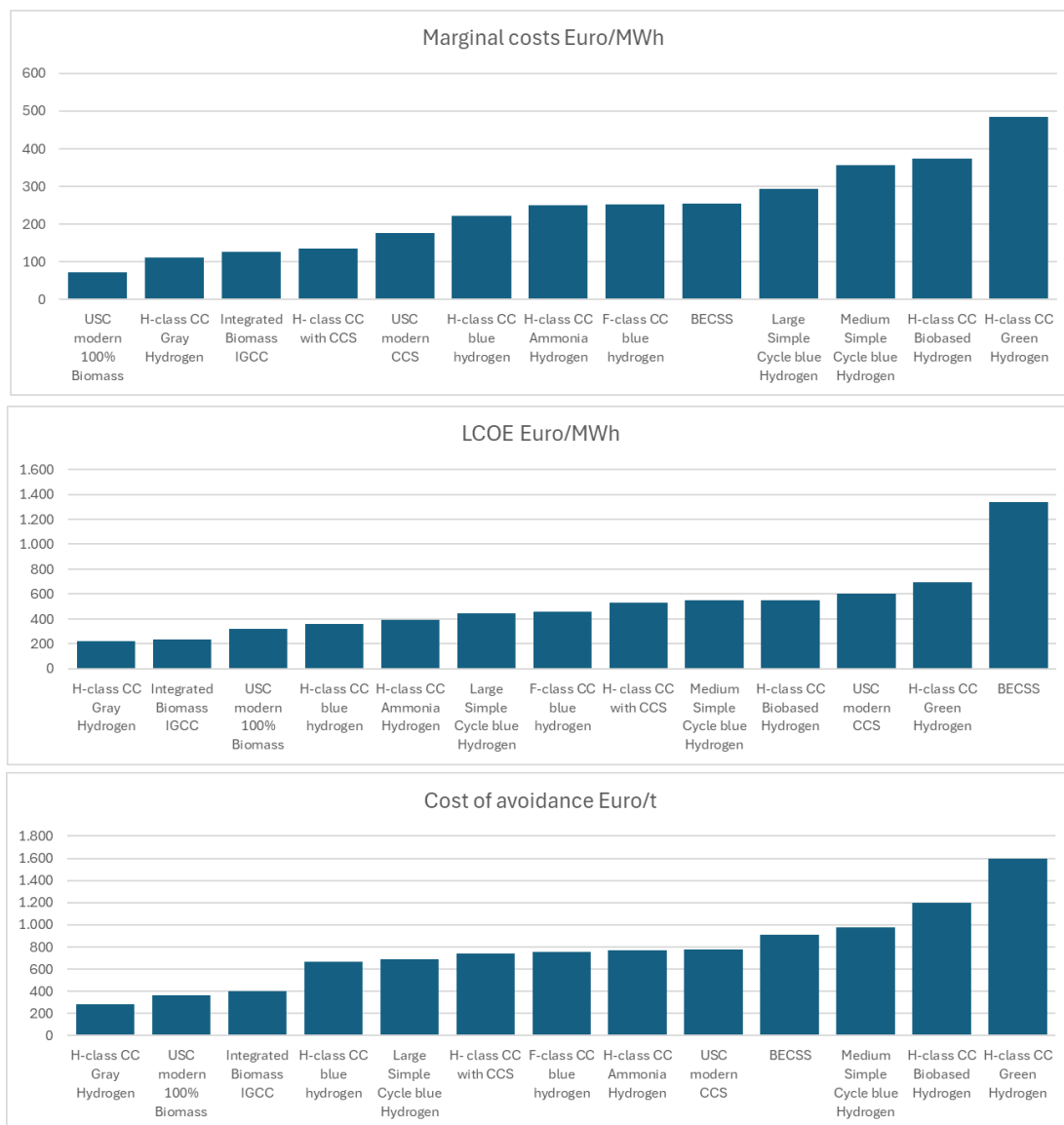


Figure 9: Marginal generation costs, LCOE and CO₂ avoidance costs at 1,000 annual full-load hours under the mid-price assumptions.

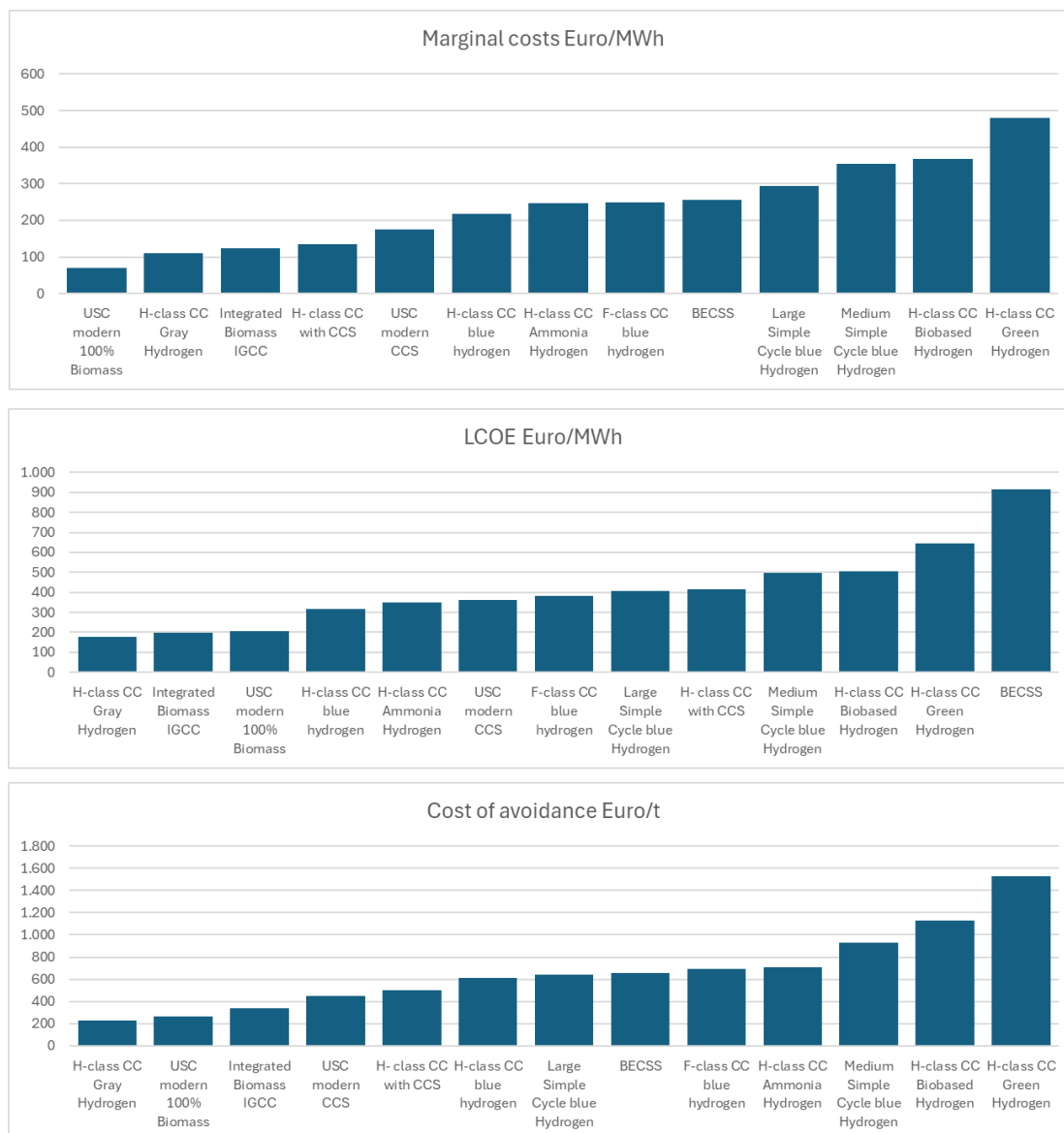


Figure 10: Marginal generation costs, LCOE and CO₂ avoidance costs at 2,000 annual full-load hours under the mid-price assumptions.

Under the mid-price assumptions, blue-hydrogen configurations exhibit substantially lower LCOE than comparable green-hydrogen configurations because of their lower assumed hydrogen supply costs. The costs of green-hydrogen generation are dominated by the electricity and capital requirements of electrolysis, together with hydrogen transport and storage costs. Biobased-hydrogen and ammonia-derived pathways occupy positions between the lowest-cost blue-hydrogen configurations and the green-hydrogen cases, reflecting their respective feedstock costs, conversion losses and infrastructure requirements. The resulting ranking is specific to the supply-cost and technology assumptions applied in this study.

CCS-equipped generation exhibits a different cost profile. H-class combined-cycle and USC configurations with CCS have comparatively high fixed costs associated with capture equipment and the supporting CO₂ transport and storage chain. They also incur an efficiency penalty from the capture process. Their LCOE therefore declines more strongly between 1,000 and 2,000 full-load hours than that of technologies with lower fixed-cost exposure. This illustrates the greater sensitivity of capital-intensive CCS pathways to the assumed annual utilisation level.

Biomass, IGCC and BECCS show distinctly different cost profiles. Under the assumptions applied, biomass IGCC and conventional USC biomass exhibit comparatively low LCOE at both illustrated utilisation levels. IGCC benefits from relatively high conversion efficiency, while the cost position of conventional biomass depends strongly on the assumed feedstock costs and operating profile. Small-scale BECCS exhibits the highest LCOE among the assessed configurations because it combines biomass feedstock costs with relatively high capital costs, CCS integration and lower conversion efficiency.

CO₂ avoidance costs reflect both the additional generation costs relative to the conventional natural-gas reference case and the emissions reduction achieved. Their ranking therefore does not necessarily coincide with the LCOE ranking. Technologies with a relatively low LCOE may still exhibit high avoidance costs where the incremental emissions reduction is limited, while technologies delivering deeper emissions reductions may occupy a different position once their modelled emissions effect is considered. BECCS illustrates this distinction: despite its high LCOE, its potential to generate negative emissions improves its relative position when assessed in terms of costs per tonne of CO₂ avoided.

The CO₂ avoidance-cost results also illustrate the different cost structures of hydrogen-based generation and CCS-equipped power generation. At 1,000 full-load hours, some blue-hydrogen turbine configurations exhibit lower CO₂ avoidance costs than the assessed CCS-based systems, partly because of their lower fixed-cost exposure at the generation-asset level. For blue hydrogen, upstream carbon-capture, compression, transport and storage costs are incorporated in the assumed hydrogen supply cost and therefore enter the assessment as part of the fuel cost of hydrogen-based generation. This result does not apply uniformly across hydrogen pathways or turbine configurations: higher hydrogen supply costs and lower conversion efficiencies may result in avoidance costs exceeding those of CCS-equipped generation. As utilisation increases, the avoidance costs of capital-intensive CCS systems decline more strongly because their fixed costs are allocated across a larger volume of electricity production.

At low utilisation levels, low capital costs provide an advantage, but high fuel costs and lower conversion efficiency may more than offset this benefit. Higher utilisation particularly improves the relative cost position of capital-intensive pathways. Moreover, the ranking based on CO₂ avoidance costs differs from the LCOE ranking.

6 Investment viability assessment

The system-cost assessment presented in the previous chapter provides insight into the relative cost-effectiveness of alternative pathways for decarbonising dispatchable generation. However, technologies that appear attractive from a system-cost perspective are not necessarily capable of recovering their costs under future market conditions.

As renewable penetration increases and annual operating hours decline, investment decisions become increasingly dependent on the ability to generate sufficient revenues during limited periods of operation. The investment perspective therefore addresses the complementary question of whether alternative pathways can recover their capital and operating costs under the utilisation levels and operating patterns considered for future low-carbon electricity systems.

This chapter addresses that question in three successive steps. First, the required-electricity-price and dispatch-spread analysis establishes the energy-market benchmark needed to cover marginal generation costs and contribute to fixed-cost recovery. Second, the revenue-recovery and cash-flow framework relates annual revenues and costs to the applicable investment criterion over the lifetime of the asset. Third, the investment-viability results compare how capital-intensive, fuel-intensive and intermediate pathways respond to different utilisation and revenue conditions.

Together, these analyses clarify the distinction between system-cost-effective and investable technologies and identify the conditions under which alternative pathways may contribute to future low-carbon dispatchable capacity.

6.1 Required electricity-price and dispatch-spread framework

6.1.1 Energy-market benchmark

For dispatchable generation, the realised dispatch spread represents the operating margin earned during the hours in which an asset is dispatched: the electricity price received minus the marginal costs of generation. These marginal costs include fuel costs adjusted for conversion efficiency, variable operating costs and, where applicable, carbon costs. The resulting margin contributes to the recovery of the asset's fixed costs.

The required dispatch spread represents the difference between the electricity price needed to meet the specified investment criterion at the assumed utilisation level and the marginal cost of generation. It therefore incorporates the recovery of fixed costs and other project-level cash-flow requirements.

This distinction is particularly relevant when comparing CCS-equipped generation with hydrogen-fired gas turbines. CCS-equipped plants require substantial capital investment in

generating equipment, carbon-capture installations and the supporting CO₂ transport and storage chain. Their relatively high annual fixed-cost requirement must therefore be covered through a combination of sufficient operating hours and operating margins. At low utilisation levels, this results in a comparatively high required dispatch spread.

Hydrogen-fired gas turbines exhibit a different cost structure. Their generating assets generally require less upfront capital investment than CCS-equipped plants, reducing the annual revenue requirement for fixed-cost recovery. Their required margin above marginal generation costs may therefore be lower. However, their marginal generation costs are generally higher because of the cost of hydrogen and the conversion efficiency of the generating asset. Consequently, a lower fixed-cost-recovery requirement does not necessarily imply a lower required electricity price: hydrogen-fired generation may still depend on relatively high-price periods to earn a positive operating margin.

The comparison therefore reveals two distinct dimensions of investment viability. Capital-intensive technologies require sufficient annual operating margins to recover high fixed costs, while fuel-intensive technologies require electricity prices high enough to cover their marginal production costs whenever they operate. The balance between these dimensions depends on the assumed utilisation level, technology-specific cost structure and electricity-market conditions.

6.1.2 Capacity-remuneration context

The required dispatch spreads presented in this study provide an energy-market benchmark. In practice, dispatchable generation may also receive revenues for making reliable capacity available. The anticipated introduction of a capacity remuneration mechanism currently under development could therefore reduce the portion of fixed costs that must be recovered through electricity-market spreads. The resulting reduction in the required spread per MWh depends on the assumed operating hours.

Where technologies receive the same CRM revenue per unit of accredited capacity, their annual revenue requirement from the energy market is reduced by the same absolute amount. The resulting reduction in the required energy-market spread per MWh nevertheless depends on the assumed operating hours: the same annual capacity revenue results in a larger reduction per MWh when allocated across a smaller volume of electricity production. This effect arises from utilisation rather than from operational flexibility or capital intensity itself.

The relative effects may differ where technologies face different capacity-accreditation factors, availability obligations, contract conditions or opportunities to combine capacity revenues with other revenue streams. These design features and the resulting CRM revenues are not explicitly modelled in this study. CRM should therefore be interpreted as relevant institutional context for the required-spread analysis rather than as a quantified component of the results. The required dispatch spreads presented here are comparative energy-market benchmarks, not predictions of realised spreads or complete project revenues.

6.2 Revenue recovery and cash-flow framework

The required-spread analysis identifies the average operating margin per MWh needed to meet the specified investment criterion at different utilisation levels. Revenue recovery depends on whether the operating margins earned, together with any other revenues, generate a sufficient annual contribution to meet the project-level revenue requirement. A technology may therefore earn a positive margin whenever it operates while still generating insufficient annual revenue to support investment.

This section takes the analysis one step further by examining how annual operating hours, cost structure and assumed revenue conditions affect cost recovery over the lifetime of the asset. The simplified discounted cash-flow models are designed to generate annual revenues, costs and free cash flows and to calculate investment indicators including internal rates of return and payback periods. The results provide indicative benchmarks for investment viability rather than bankable project evaluations.

6.2.1 Analytical framework

The cash-flow models combine annual electricity production and revenues with capital expenditure, fixed and variable operating costs, fuel costs, conversion efficiency, start-up and operating characteristics, carbon costs, taxation and financing assumptions over the lifetime of the asset. Annual utilisation and electricity-price conditions are specified as model assumptions rather than derived from hourly market-clearing or dispatch modelling. The calculations therefore assess investment outcomes under stylised operating and revenue conditions; they do not predict realised dispatch, electricity prices or market revenues.

6.2.2 Assessed technology cases

Cash-flow analyses were performed for thirteen assessed dispatchable generation concepts, covering hydrogen-based generation pathways, CCS-equipped thermal generation, biomass-based generation, BECCS and IGCC systems, together with a grey-hydrogen reference case. The cases span different combinations of fixed-cost exposure, fuel intensity, conversion efficiency and operational characteristics.

For comparative purposes, the assessed cases are grouped according to their dominant cost structure. Particular attention is given to the distinction between pathways characterised by high capital intensity and comparatively low marginal operating costs, and pathways with lower capital requirements but higher fuel-related marginal costs.

As shown in Table 6, biomass and IGCC pathways occupy an intermediate position between fuel-intensive hydrogen pathways and capital-intensive CCS pathways. The grouping is analytical rather than absolute: every pathway contains both fixed and variable cost components, but their relative importance determines sensitivity to utilisation and the revenue conditions required for cost recovery.

Table 6: Assessed technology pathways grouped by dominant cost structure

Cost structure	Technology pathway	Configuration
Fuel-intensive	Blue hydrogen	F-class Combined Cycle
Fuel-intensive	Blue hydrogen	H-class Combined Cycle
Fuel-intensive	Blue hydrogen	Large Simple Cycle
Fuel-intensive	Blue hydrogen	Medium Simple Cycle
Fuel-intensive	Green hydrogen	H-class Combined Cycle
Fuel-intensive	Biobased hydrogen	H-class Combined Cycle
Fuel-intensive	Ammonia-derived hydrogen	H-class Combined Cycle
Fuel-intensive	Grey hydrogen (reference case)	H-class Combined Cycle
Intermediate	Biomass	USC Modern Biomass
Intermediate	Biomass-derived syngas	IGCC
Capital-intensive	CCS	H-class Combined Cycle with CCS
Capital-intensive	CCS	USC Coal with CCS
Capital-intensive	BECCS	Biomass with CCS

6.3 Investment viability results

The cash-flow results show how differences in fixed-cost exposure, fuel intensity and operating assumptions translate into different revenue-recovery requirements and investment outcomes. The following sections examine capital-intensive and fuel-intensive pathways before comparing the investment exposures of these pathways and the intermediate configurations assessed.

6.3.1 Capital-intensive pathways

CCS-equipped thermal generation technologies are characterised by comparatively high fixed-cost exposure. In addition to investment in the generating asset, these pathways require capital expenditure for carbon-capture equipment and, depending on the system boundary applied, supporting CO₂ compression, transport and storage infrastructure. The capture process also reduces conversion efficiency and may introduce additional operating and maintenance requirements.

As a result, the annual revenue requirement of CCS-equipped generation is relatively sensitive to utilisation. At lower annual operating hours, fixed and other project-level costs must be recovered from a smaller volume of electricity production, increasing the required electricity price and corresponding dispatch spread. Higher utilisation distributes these costs across more output, but contributes to investment recovery only where the additional operating hours generate sufficient margins above marginal generation costs. Higher utilisation is therefore not sufficient by itself to establish investment viability: the contribution to cost recovery depends on both the number of operating hours and the margins earned during those hours.

As discussed in Section 5.4.1, cycling, part-load operation and process-stabilisation requirements may also affect the effective electricity output and operating costs of CCS-

equipped generation. These operational effects may further influence revenue recovery, but should be interpreted only to the extent that they are represented in the cash-flow models.

The assessment therefore identifies a central investment challenge for capital-intensive pathways: their high annual fixed-cost requirement creates a stronger dependence on sufficient cumulative operating margins. Their investment viability consequently depends on the interaction between fixed-cost exposure, annual utilisation, electricity prices received and the applicable investment criterion. Capacity or other availability-related revenues could reduce the portion of this requirement that must be recovered through the energy market, as discussed in Section 6.1.2.

6.3.2 Fuel-intensive pathways

Fuel-intensive pathways exhibit a different investment profile from capital-intensive pathways because a larger proportion of their total costs is incurred when electricity is produced. Hydrogen-capable gas turbines generally have comparatively low fixed-cost exposure at the generation-asset level, but relatively high marginal generation costs resulting from hydrogen supply costs and conversion losses.

Their lower fixed-cost exposure reduces the annual revenue requirement for fixed-cost recovery. At low utilisation levels, the required operating margin above marginal generation costs may therefore remain lower than for more capital-intensive pathways. This does not necessarily imply a lower required electricity price, however. Before contributing to fixed-cost recovery, electricity-market revenues must first cover the comparatively high marginal costs of hydrogen-fired generation.

The investment viability of these pathways consequently depends on two distinct conditions. The generating asset must earn sufficient cumulative operating margins to recover its fixed costs, while electricity prices during dispatch must be high enough to cover hydrogen supply and other variable costs. Fuel-intensive pathways can therefore be compatible with selective operation during relatively high-price periods, but lower utilisation is not itself economically advantageous and does not guarantee cost recovery.

Differences among hydrogen pathways primarily arise from hydrogen supply costs and, where different generating configurations are compared, conversion efficiency and capital requirements. Under the assumptions used in this study, blue-, green-, biobased- and ammonia-derived hydrogen therefore result in different required electricity prices and revenue-recovery profiles. Grey hydrogen is included only as a reference case.

The assessment therefore identifies the central investment challenge for fuel-intensive pathways: comparatively low fixed costs limit the amount of annual revenue required for capital recovery, but high marginal generation costs restrict profitable operation to hours in which electricity prices are sufficiently high. Their investment viability depends on the frequency and duration of such periods, the margins realised during them and any additional capacity- or service-related revenues.

6.3.3 Comparison across pathways

The comparison across pathways reveals that investment viability is determined by the interaction between marginal generation costs, fixed-cost exposure, annual utilisation and the

electricity prices received during operating hours. No single cost characteristic determines investment viability independently. Operational flexibility may expand the range of operating conditions in which a technology can participate, but creates economic value only where that operation generates a positive margin.

Hydrogen-fired gas turbines combine comparatively low fixed-cost exposure with relatively high marginal generation costs. They consequently require less annual revenue for fixed-cost recovery than capital-intensive pathways, but depend on electricity prices being sufficiently high to cover hydrogen supply costs and conversion losses. Their investment case is therefore relatively compatible with selective operation during high-price periods, provided that sufficient cumulative margins can be earned.

CCS-equipped generation exhibits the converse profile. Its marginal generation costs may be lower than those of some hydrogen pathways, but its comparatively high fixed-cost requirement creates a stronger dependence on cumulative annual operating margins. Declining utilisation therefore increases the average margin required during the remaining operating hours. Additional operating hours improve investment recovery only where they yield positive margins after variable and operational costs.

Biomass, biomass-derived syngas and BECCS pathways combine fixed- and variable-cost characteristics in different proportions and cannot be represented by a single common profile. Their investment viability depends on the interaction between capital intensity, feedstock costs, conversion efficiency and operational characteristics. BECCS additionally provides potential negative emissions, but any corresponding revenue contribution depends on whether and how this value is monetised. It is therefore considered separately from electricity-market revenue in the investment assessment.

Taken together, the pathways represent different investment exposures rather than a universal ranking of investability. Fuel-intensive technologies are particularly exposed to fuel prices and the occurrence of sufficiently high electricity-price periods. Capital-intensive technologies are more exposed to annual utilisation and the cumulative margins available for fixed-cost recovery. Intermediate pathways combine both exposures. Utilisation should therefore not be interpreted as an independent or universally dominant driver of investment viability: additional operating hours support investment recovery only where they generate positive margins. Capacity or other availability-related revenues may reduce the fixed-cost requirement to be recovered through the energy market, but do not remove the need to cover marginal generation costs when electricity is produced.

7 Transition pathways and policy implications

Chapter 5 assessed the system-cost performance and operational suitability of the evaluated pathways, considering their cost structures, potential system roles, merit-order positions, operational flexibility, LCOE and CO₂ avoidance costs. Chapter 6 examined the complementary private-investment perspective by assessing the electricity prices, dispatch spreads and cumulative revenues required to recover costs under different utilisation conditions.

These perspectives show that system-cost effectiveness, operational suitability and private investability are related but distinct. A pathway that appears cost-effective from a system perspective may not generate sufficient market revenues to attract investment. Conversely, a pathway that is comparatively investable under particular market conditions does not necessarily provide the most cost-effective contribution to public objectives.

This distinction is important because the deployment of low-carbon dispatchable generation ultimately depends on the alignment between public value and private delivery. Technologies must contribute to a sustainable, affordable and reliable electricity system, while investors must be able to recover their costs under the applicable market and policy arrangements. Differences in cost structure, operational characteristics and infrastructure requirements therefore translate into different system contributions, investment exposures and enabling conditions.

This chapter integrates the findings from the system-cost and investment assessments. It first characterises the main techno-economic pathway archetypes emerging from the analysis. It then assesses their implications for sustainability, affordability, reliability and private investability. Finally, it identifies the principal implications for transition pathways, market design and policy, and formulates hypotheses for further assessment through the power-system simulations.

7.1 Integrated assessment of pathway archetypes

The system-cost and investment assessments show that the evaluated pathways differ not only in their total costs, but also in the distribution of costs between fixed investment requirements and marginal generation costs. These differences interact with conversion efficiency, operational suitability and infrastructure dependence, resulting in distinct techno-economic profiles. Table 7 provides an integrated qualitative synthesis of these profiles. The archetypes are intended to clarify the principal trade-offs identified in the assessment; they do not constitute a universal technology ranking or a prediction of the future generation mix. Actual system roles will depend on future fuel and carbon prices, renewable-generation patterns, infrastructure availability, market design and the utilisation realised by individual assets.

Table 7: Overview of techno-economic input parameters and data sources used in the assessment

Pathway archetype	Cost structure	Marginal-cost exposure	Fixed-cost-recovery exposure	Operational suitability	Indicative system-role alignment	Critical enabling conditions
Hydrogen-fired OCGT	Predominantly fuel-intensive	High; driven by hydrogen supply costs and relatively low conversion efficiency	Low relative to the other assessed pathways	High suitability for rapid start-up, ramping and repeated short-duration operation	Short-duration scarcity response and peaking	Availability and cost of low-carbon hydrogen; hydrogen transport and storage; sufficient high-price periods; capacity or other availability-related revenues
Hydrogen-fired CCGT	Fuel-intensive, with higher capital requirements and greater efficiency than OCGT	High, but moderated by higher conversion efficiency	Low–moderate	Relatively high suitability for flexible operation, with longer start-up requirements than OCGT	Longer-duration peak support and potential mid-merit operation	Availability and cost of low-carbon hydrogen; hydrogen infrastructure; sufficient operating margins
CCS-equipped thermal generation	Predominantly capital-intensive	Moderate–high, depending on fuel costs, capture-related efficiency losses and residual carbon costs	High	Moderate; start-up, cycling and process-stabilisation requirements affect short-duration operation	More sustained dispatch and potential mid-merit operation	Sufficient cumulative operating margins; access to CO ₂ transport and permanent storage; performance of the capture chain; investable revenue arrangements
Conventional biomass steam-cycle generation	Intermediate, with material fixed and feedstock costs	Moderate–high and sensitive to biomass prices and conversion efficiency	Moderate–high	Moderate; generally more suited to longer operating periods than repeated short-duration activation	More sustained dispatch and potential mid-merit operation	Sustainable feedstock availability; logistics and competing biomass uses; sufficient utilisation and operating margins
Combined-cycle generation using biomass-derived syngas*	Intermediate	Sensitive to syngas supply costs and conversion efficiency	Moderate	Potentially moderate–high, depending on the included technology configuration	Flexible or mid-merit operation	Technology maturity; feedstock and syngas logistics; integration of gasification and generation; confirmation of the applied system boundary
BECCS	Predominantly capital-intensive, combined with material feedstock costs	Moderate–high and sensitive to biomass costs and conversion efficiency	High	Low–moderate; biomass conversion and capture processes constrain short-duration operation	More sustained generation combined with potential carbon removal	Sustainable biomass supply; CO ₂ transport and permanent storage; reliable carbon-removal accounting and remuneration; sufficient cumulative revenues

The comparison highlights two principal investment exposures. Hydrogen-fired generation has comparatively low fixed-cost exposure at the generating-asset level but remains strongly exposed to fuel costs and the occurrence of electricity prices high enough to cover its marginal generation costs. CCS-equipped generation and BECCS face greater fixed-cost-recovery exposure and consequently depend more strongly on sufficient cumulative margins. Conventional biomass and biomass-derived syngas configurations combine these exposures in different proportions.

Operational suitability introduces a related but distinct dimension. Rapid start-up and ramping capabilities may align a technology with short-duration scarcity operation, while technologies with greater thermal inertia or process-integration requirements may be better aligned with longer and more sustained activation. These alignments do not determine actual dispatch or adequacy contributions, which depend on system conditions.

The archetypes should therefore be understood as different combinations of costs, operational characteristics and delivery requirements rather than as mutually exclusive technology choices. Their contribution to future electricity systems must ultimately be assessed against the public objectives of sustainability, affordability and reliability, together with the private-investment and infrastructure conditions required for delivery.

7.2 Implications for public values and delivery

The techno-economic archetypes identified in the preceding section contribute differently to the objectives of a future electricity system. Their policy relevance therefore cannot be determined from a single cost or performance indicator. An integrated assessment must consider whether pathways contribute to sustainability, affordability and reliability, as well as whether the investments and supporting value chains required to deliver those contributions can be realised.

These dimensions are related but not interchangeable. A pathway with low emissions may involve comparatively high costs; a technology capable of providing reliable capacity may not recover its costs through the energy market; and an investable technology does not necessarily provide the most cost-effective contribution to public objectives. The following sections examine these dimensions separately before considering their interaction.

7.2.1 Sustainability

The sustainability contribution of dispatchable generation depends primarily on the emissions associated with electricity production and its upstream fuel and infrastructure chains. The present assessment focuses on CO₂ emissions and should not be interpreted as a comprehensive assessment of all environmental and social impacts.

Hydrogen-fired generation produces no direct CO₂ emissions at the point of combustion, but its overall emissions performance depends on how the hydrogen is produced, converted, transported and stored. Green-hydrogen pathways are strongly influenced by the carbon intensity and availability of the electricity used for electrolysis. Blue-hydrogen pathways retain residual emissions from hydrogen production and may also be affected by upstream methane emissions and the capture rate achieved. Biobased hydrogen and ammonia-derived pathways have their own conversion losses, supply-chain emissions and sustainability

considerations. The designation of a fuel as low-carbon therefore does not by itself determine its full emissions performance.

For CCS-equipped generation, the emissions reduction depends on the capture rate, the efficiency penalty associated with carbon capture and the emissions arising from the remaining fuel and infrastructure chain. CCS substantially reduces direct emissions but does not necessarily eliminate them. Its sustainability contribution consequently depends on both the emissions captured and the residual emissions per unit of electricity produced.

Biomass-based generation raises additional questions concerning feedstock origin, land and resource availability, competing uses and applicable sustainability criteria. BECCS may generate net-negative emissions where biogenic carbon is sustainably sourced, effectively captured and permanently stored. This potential distinguishes BECCS from the other pathways, but the magnitude and permanence of the resulting removals depend on the full biomass and carbon-management chain.

The CO₂ avoidance costs calculated in this study compare each technology with a conventional natural-gas reference based on technology-specific costs and emissions intensities. They should therefore be interpreted as technological avoidance costs rather than as system-wide or marginal emissions-reduction costs. The calculations do not determine which generating unit would actually be displaced in the electricity market. That question requires the system-level dispatch analysis undertaken in WP2.

7.2.2 Affordability

Affordability concerns the cost at which the assessed pathways can contribute to a low-carbon electricity system. The LCOE and CO₂ avoidance-cost results provide comparative information on technology-level cost performance, but do not represent the full costs of the electricity system.

The results show that cost structure is central to the effect of utilisation. For capital-intensive pathways, declining utilisation allocates fixed and project-level costs across a smaller volume of electricity production, increasing LCOE. Fuel-intensive pathways are less exposed to this effect at the generation-asset level, but may nevertheless have high LCOE because fuel costs and conversion losses dominate the cost of each MWh produced. Low capital intensity therefore does not necessarily imply low generation costs, just as relatively low marginal costs do not imply low total costs.

The ranking based on CO₂ avoidance costs may differ from the LCOE ranking because avoidance costs reflect both incremental generation costs and the emissions reduction achieved relative to the reference case. A technology with relatively low LCOE may still have high avoidance costs where its additional emissions reduction is limited. Conversely, a pathway delivering deep or net-negative emissions may occupy a different position when assessed per tonne of CO₂ avoided.

These indicators do not capture all system-level costs and benefits. The wider affordability of a pathway may also depend on network reinforcement, fuel production and storage, CO₂ transport and storage, balancing requirements, infrastructure utilisation and interactions with other electricity-system resources. Some of these costs are incorporated in the assumed technology or fuel costs, while others fall outside the applied system boundary. The results

should therefore be used to compare the assessed configurations under common assumptions, not as a complete ranking of their contribution to total electricity-system costs.

7.2.3 Reliability

Reliability concerns the ability of the electricity system to supply electricity when required, including during periods of low renewable output, peak demand and prolonged system stress. Dispatchable technologies may contribute to this objective in different ways, depending on their start-up behaviour, ramping capability, cycling performance, operating-duration constraints and dependence on fuel and infrastructure availability.

The FMPE assessment provides a comparative indication of operational suitability within the assumed activation window. Technologies with rapid start-up and ramping capabilities can convert a larger part of a short activation period into electricity production. Technologies with greater thermal inertia or process-stabilisation requirements may be better suited to longer and more sustained periods of operation. A lower FMPE score therefore does not imply that a technology cannot contribute to reliability; it indicates that its potential contribution is aligned with a different operating profile.

Reliability requirements are themselves heterogeneous. Short scarcity events may favour technologies capable of rapid activation and repeated cycling, whereas prolonged periods of low renewable generation require resources capable of sustained operation and access to sufficient fuel, storage and supporting infrastructure. The reliability contribution of a pathway consequently depends not only on generating technology but also on the resilience and availability of the associated hydrogen, biomass, natural-gas, electricity and CO₂ chains.

FMPE is not a measure of system adequacy or firm-capacity contribution. It does not determine how often a technology will be required, whether sufficient capacity will be available during system stress, or how different resources interact within the electricity system. Capacity accreditation and adequacy contributions must therefore be established through system-level modelling. WP2 will assess these questions by evaluating dispatch, scarcity conditions and adequacy within an integrated future electricity system.

7.2.4 Investability and delivery

Public-value contributions can be realised only if the required generation assets, infrastructure and supply chains are developed and maintained. Investability is therefore treated here as a delivery condition: it concerns whether private investors can recover their costs and obtain the required return under the applicable market and policy arrangements.

The analysis distinguishes between the electricity price required to cover marginal generation costs and the operating margin required to meet fixed and other project-level cash-flow requirements. Fuel-intensive pathways may require comparatively limited fixed-cost recovery but remain dependent on high electricity prices to cover fuel costs. Capital-intensive pathways may have lower marginal costs but require sufficient cumulative margins across the year to recover substantial upfront investments. System-cost effectiveness therefore does not automatically translate into private investability.

Energy-market revenues may be supplemented by revenues for capacity availability, ancillary services or other system contributions. A capacity-remuneration mechanism could reduce the

portion of fixed costs that must be recovered through electricity-market spreads. Its effect will depend on the design of the mechanism, including capacity accreditation, availability obligations, contract duration and interaction with energy-market revenues. Such revenues do not remove the need to cover marginal generation costs when electricity is produced.

Delivery also depends on risks that extend beyond the generating asset. Hydrogen-fired generation requires the timely availability of low-carbon hydrogen production, transport and storage. CCS-equipped generation depends on access to a functioning CO₂ transport and permanent-storage chain. Biomass and BECCS require sustainable feedstock supply and supporting logistics. Uncertainty over the timing, cost and accessibility of these infrastructures may materially affect investment even where the generating technology itself appears viable.

The distinction between public value and private delivery is therefore central to the assessment. A system-cost-effective pathway is not necessarily privately investable, while an investable technology does not necessarily provide the most cost-effective contribution to public objectives. Policy must consequently consider both which system contributions are required and whether market arrangements, infrastructure development and risk allocation provide credible conditions for their delivery.

7.3 Transition and policy implications

The assessment identifies structural differences between the evaluated pathways but does not establish a universally preferred technology or an optimal future generation mix. Its principal policy implication is that decisions concerning low-carbon dispatchable generation must consider system contribution, cost structure, operational suitability, investability and infrastructure dependence together.

7.3.1 A portfolio rather than a single technology ranking

The assessment points to complementary techno-economic functions rather than a universal technology ranking. Technologies with relatively low fixed-cost exposure and strong operational flexibility may be aligned with short-duration scarcity operation, while capital-intensive technologies may require more sustained operation and cumulative market margins. Other pathways may provide additional functions, including the potential delivery of negative emissions.

These differences do not by themselves demonstrate that all pathways will be required or determine their appropriate scale. Nor do they imply that each technology should receive a distinct form of policy support. They indicate that comparisons based on a single indicator—such as marginal generation costs, LCOE, operational flexibility or capital intensity—provide an incomplete basis for technology selection.

Policy assessment should therefore start from the system contribution required under different future conditions. Relevant contributions may include rapid response during short scarcity events, sustained generation during prolonged periods of low renewable output, firm-capacity availability and, where applicable, carbon removal. The technologies capable of providing these contributions can then be compared in terms of their full costs, emissions performance, operational suitability and delivery requirements.

7.3.2 Alignment of remuneration with system contribution

The pathways assessed in this study face different revenue exposures. Fuel-intensive technologies depend on electricity prices being sufficiently high to cover marginal generation costs whenever they operate. Capital-intensive technologies depend more strongly on earning sufficient cumulative margins to recover fixed and project-level costs. A technology may therefore be operationally suitable and system-cost-effective while remaining unable to recover its costs from the revenues available in the market.

This does not automatically justify technology-specific remuneration. It does imply that market and policy design should distinguish between the system contribution being procured and the mechanism through which that contribution is remunerated. Energy-market revenues reward electricity production, while capacity or availability payments may remunerate the ability to produce during scarcity. Ancillary-service revenues may reward specific operational capabilities, and carbon-market or removal revenues may value emissions reductions or removals that are not reflected fully in electricity prices.

Policy design should therefore examine:

- which system performance or availability is required;
- whether existing market revenues remunerate that contribution;
- which market and infrastructure risks investors can reasonably manage;
- whether residual missing-money, coordination or risk-allocation problems remain.

A capacity-remuneration mechanism could reduce the share of fixed costs that must be recovered through energy-market margins. Its effect will depend on capacity accreditation, availability obligations, contract duration, penalties and interaction with electricity-market revenues. Technology-neutral design does not necessarily produce identical economic effects across technologies, but differences in those effects should not be interpreted as an inherent justification for favouring a particular pathway.

The appropriate remuneration framework consequently depends on the system contribution sought rather than on technology characteristics alone. Any intervention should also preserve efficient operational incentives: capacity or availability revenues may support fixed-cost recovery, but generating assets should still face incentives reflecting their marginal costs and the value of electricity during scarcity.

7.3.3 Infrastructure and value-chain coordination

Investment in dispatchable generation cannot be considered independently of the infrastructure and supply chains on which it depends. Hydrogen-fired generation requires timely access to low-carbon hydrogen production, transport and storage. CCS-equipped generation depends on CO₂ capture, compression, transport and permanent storage. Biomass and BECCS require sustainable feedstock supply, logistics and, for BECCS, access to the CO₂ transport and storage chain.

These interdependencies can create coordination problems. Investment in generating capacity may depend on confidence that the supporting infrastructure will be available, while investment in shared infrastructure may depend on expectations regarding future demand

and utilisation. Uncertainty about timing, tariffs, access conditions and cost allocation may therefore delay otherwise potentially viable investments.

Policy should consequently consider the generating asset and its supporting value chain as a connected delivery system. This requires coordination of infrastructure planning, market development, permitting and investment decisions. It also requires transparent system boundaries: costs assigned to fuel supply or shared infrastructure must not disappear from the assessment merely because they fall outside the generating asset itself.

Shared infrastructure may create wider option value by enabling more than one technology, user or future development pathway. At the same time, premature commitment to infrastructure designed around a narrow set of assumptions may create lock-in or underutilised assets. Coordination should therefore take account of both economies of scale and uncertainty over future utilisation.

7.3.4 Sequencing and optionality

Future operating hours, fuel costs, carbon prices, infrastructure availability and market arrangements remain uncertain. Transition decisions should therefore consider not only expected end-state performance but also sequencing, lock-in risks and the option value of adaptable assets and shared infrastructure.

Technologies that appear attractive in a particular end-state scenario may not be immediately investable if the required infrastructure, fuels or revenue arrangements are not yet available. Conversely, investments made to address near-term adequacy or decarbonisation needs may retain value if they can be adapted to alternative fuels, operating profiles or system functions as conditions change.

Optionality should not be interpreted as an argument for postponing decisions or preserving every pathway. Maintaining options also involves costs, and some infrastructure choices require early commitment and long development periods. The relevant policy question is therefore which decisions must be taken early, which can remain conditional, and where flexibility in technology, contracts or infrastructure design has sufficient value to justify its cost.

Sequencing is particularly important where investments are mutually dependent. Generation assets, fuel production, transport networks, storage facilities and CO₂ infrastructure may need coordinated development even where their eventual utilisation remains uncertain. Transition strategies should therefore combine credible near-term investment conditions with periodic reassessment as information about costs, demand, system needs and technology performance improves.

7.3.5 Hypotheses for system simulation

The potential system roles identified in this chapter should be interpreted as techno-economic hypotheses rather than definitive deployment outcomes. The present assessment identifies differences in cost structure, marginal-cost exposure, operational suitability, revenue requirements and enabling conditions. It does not determine the optimal capacity mix or the actual dispatch and revenue position of individual technologies in a future electricity system.

The second work package in this study will test these hypotheses through integrated power-system simulation. The analysis should assess:

- the operating hours and dispatch patterns emerging under alternative renewable-generation and demand conditions;
- the technologies displaced during operation and the resulting system-wide emissions effects;
- the duration and frequency of scarcity events;
- captured electricity prices and operating margins;
- adequacy and firm-capacity contributions;
- interactions with storage, interconnection and demand-side flexibility;
- revenue recovery and investment outcomes under alternative market-design assumptions.

This system-level analysis will show whether the indicative alignments identified in this report remain valid once technologies compete and interact within the same electricity system. It will also provide the basis for assessing whether complementary pathways are required, where investment gaps may arise and which market or policy arrangements could address those gaps.

8 Conclusions

The assessment demonstrates that the challenge of decarbonising dispatchable generation extends beyond the selection of individual technologies. The evaluated pathways differ in their cost structures, operational characteristics, emissions performance, infrastructure requirements and conditions for investment recovery. The main conclusions and policy implications are summarised below.

- **Conclusion 1: Dispatchable low-carbon generation remains costly under low-utilisation conditions**

The study assessed a range of low-carbon dispatchable generation technologies that may contribute to maintaining security of supply in a highly decarbonised electricity system. The results highlight a broader challenge: providing low-carbon dispatchable capacity under low-utilisation conditions is costly across the pathways assessed.

As annual operating hours decline, fixed and other project-level costs must be recovered from a smaller volume of electricity production, increasing generation costs, particularly for capital-intensive technologies. Technologies with lower capital intensity are less sensitive to this effect, but may nevertheless face high generation costs where fuel costs and conversion losses dominate. The challenge therefore extends along the supply chain for hydrogen-, CCS- and biomass-based pathways, although its origin and magnitude differ between technologies.

- **Conclusion 2: Different technologies may fulfil different system roles**

The results should not be interpreted solely as a direct comparison between hydrogen-fired generation and CCS-equipped thermal plants. Instead, they illustrate trade-offs between different technological approaches to delivering low-carbon dispatchable capacity.

Hydrogen-fired gas turbines combine comparatively low fixed-cost exposure with relatively high marginal generation costs and strong operational suitability for short-duration activation. CCS-equipped pathways have higher fixed-cost-recovery requirements and may therefore require more sustained cumulative operating margins. Biomass, biomass-derived syngas and BECCS combine capital, feedstock and operational exposures in different proportions.

These characteristics indicate potential alignment with different system roles. They do not determine actual dispatch, adequacy contributions or the optimal technology mix, which depend on wider electricity-system conditions.

- **Conclusion 3: Market design and revenue recovery affect technology deployment**

System-cost effectiveness and private investability are related but distinct. Technologies that appear cost-effective under the assumed utilisation conditions do not necessarily provide investable business cases, while technologies capable of recovering their

investment costs do not necessarily provide the most cost-effective contribution to public objectives.

Fuel-intensive technologies depend on electricity prices being sufficiently high to cover marginal generation costs. Capital-intensive technologies depend more strongly on earning sufficient cumulative margins to recover fixed costs. Capacity or other availability-related revenues could reduce the share of fixed costs that must be recovered through energy-market spreads, but do not remove the need to cover marginal costs during operation.

- **Conclusion 4: The assessment identifies potentially complementary functions rather than a single preferred pathway**

Dispatchable generation represents one component of a wider flexibility portfolio that may also include energy storage, demand-side flexibility, interconnection and sector coupling. The role of dispatchable generation should therefore be assessed within this wider system context rather than as a standalone solution.

Within the technologies assessed, differences in cost structure and operational suitability point to potentially complementary techno-economic functions rather than a universally preferred pathway. The study does not establish that all pathways will be required or determine their appropriate scale. The optimal composition of future dispatchable and flexible capacity cannot be determined through comparative techno-economic assessment alone.

- **Conclusion 5: Implications for policy and further analysis**

Policy assessment should begin with the system contribution required, such as rapid response during short scarcity events, sustained generation during prolonged periods of low renewable output, firm-capacity availability or, where applicable, carbon removal. Technologies capable of providing these contributions can then be compared in terms of cost, emissions, operational suitability, investability and infrastructure requirements.

Because future utilisation, fuel costs, infrastructure availability and market arrangements remain uncertain, transition decisions should also consider sequencing, coordination and optionality. The potential system roles identified in this study should be interpreted as techno-economic hypotheses rather than deployment recommendations. A simulation study in the second work package of this study will further assess these hypotheses through integrated power-system simulation, including dispatch, captured electricity prices, adequacy contributions, system-wide emissions effects and investment recovery.

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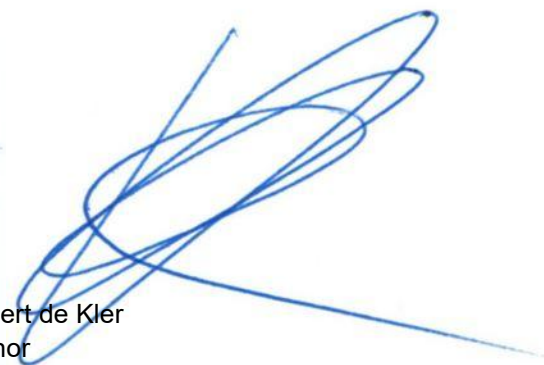
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Signature

TNO) Energy & Materials Transition) Rijswijk, 14 September 2026

A handwritten signature in blue ink, consisting of several loops and a long horizontal stroke extending to the right.

J.B. de Bes
Research manager

A handwritten signature in blue ink, featuring a large, complex loop structure with multiple overlapping strokes.

Robert de Kler
Author

J.S. Hers
Reviewer

T. Speelman
Reviewer

Appendix A

Market Prices

Ammonia	euro / MWh (th)	low	75,0
	euro / MWh (th)	mid	100,0
	euro / MWh (th)	high	125,0
Biomass	euro / MWh (th)	low	18,0
	euro / MWh (th)	mid	24,0
	euro / MWh (th)	high	28,0
Coal	euro / MWh (th)	low	8,6
	euro / MWh (th)	mid	13,0
	euro / MWh (th)	high	17,3
Syngas	euro / MWh (th)	low	60,4
	euro / MWh (th)	mid	71,1
	euro / MWh (th)	high	84,3
Hydrogen (bio)	euro / MWh (th)	low	187,6
	euro / MWh (th)	mid	222,1
	euro / MWh (th)	high	257,3
Hydrogen (grey)	euro / MWh (th)	low	50,3
	euro / MWh (th)	mid	64,0
	euro / MWh (th)	high	80,5
Hydrogen (blue)	euro / MWh (th)	low	106,5
	euro / MWh (th)	mid	131,3
	euro / MWh (th)	high	161,2
Hydrogen (ammonia)	euro / MWh (th)	low	114,0
	euro / MWh (th)	mid	147,3
	euro / MWh (th)	high	183,1
Hydrogen (green)	euro / MWh (th)	low	206,4
	euro / MWh (th)	mid	293,1
	euro / MWh (th)	high	413,1

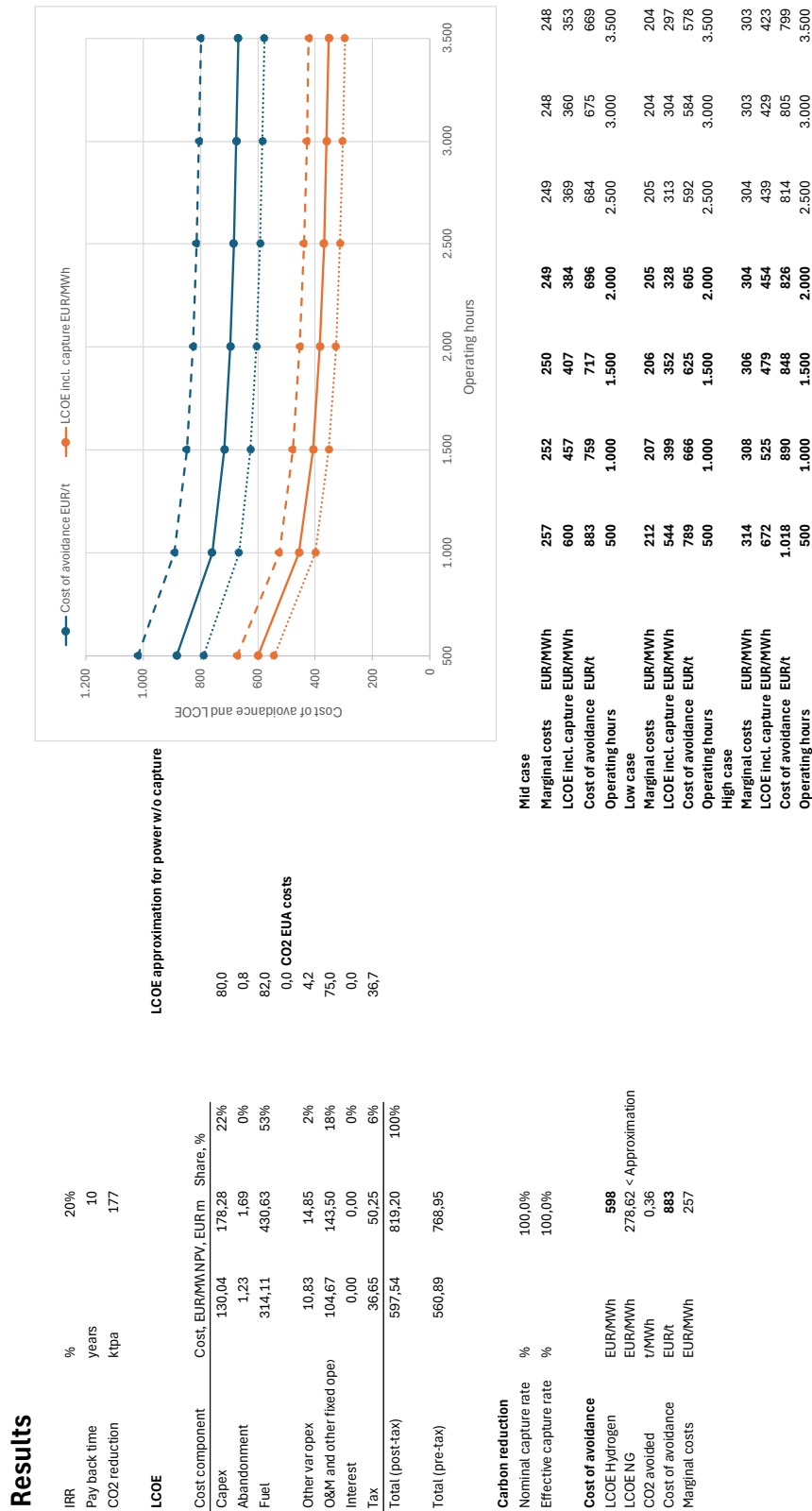
Ammonia price	euro / MWh (th)	low	75,0
	euro / MWh (th)	mid	100,0
	euro / MWh (th)	high	125,0
CO2 ETS	euro / t	mid	75,0

Appendix B

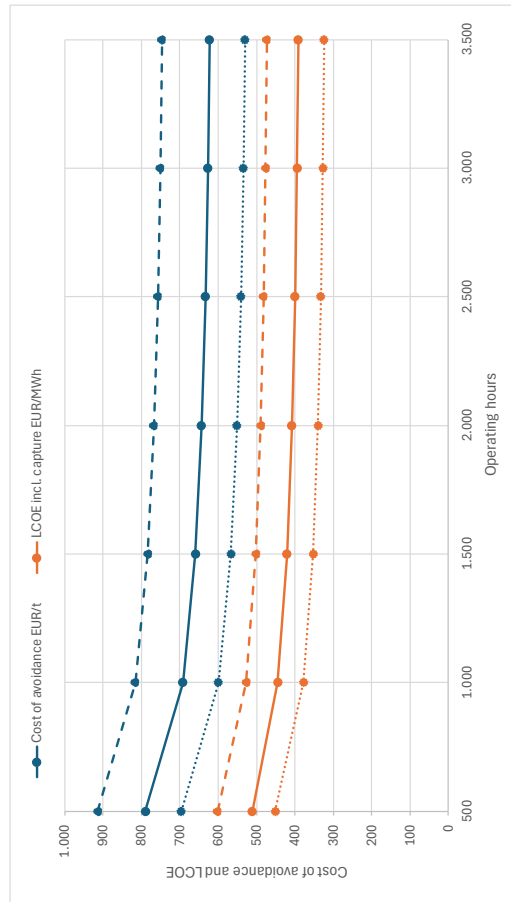
Cash flow analyses

Results are also provided by the separate cash flow analyses excel work books.

Application 1 F-class CC Blue Hydrogen



Application 2 Large OCGT Blue Hydrogen



LCOE approximation for pow

CO2 EUA costs

Results

IRR	%	21%
Pay back time	years	10
CO2 reduction	ktpa	364

LCOE

Cost component	Cost, EUR/MM	NPV, EUR m	Share, %
Capex	26,51	56,31	5%
Abandonment	0,25	0,53	0%
Fuel	440,79	936,22	84%
Other var opex	12,36	26,24	2%
O&M and other fixed opex	42,44	90,13	8%
Interest	0,00	0,00	0%
Tax	4,38	9,31	1%
Total (post-tax)	526,73	1.118,75	100%
Total (pre-tax)	522,35	1.109,44	

Carbon reduction

Nominal capture rate	%	100,0%
Effective capture rate	%	100,0%

Cost of avoidance

LCOE Hydrogen	EUR/MWh	526,73
LCOE NG	EUR/MWh	170,26 < Approximation
CO2 avoided	t/MWh	0,44
Cost of avoidance	EUR/t	8,16
Margin cost	EUR/MWh	359

Mid case

Marginal cost	295	294	294	293	293	293
LCOE incl. capture EUR/MWh	512	445	420	408	400	395
Cost of avoidance EUR/t	789	692	659	643	633	627
Operating hours	500	1.000	1.500	2.000	2.500	3.000

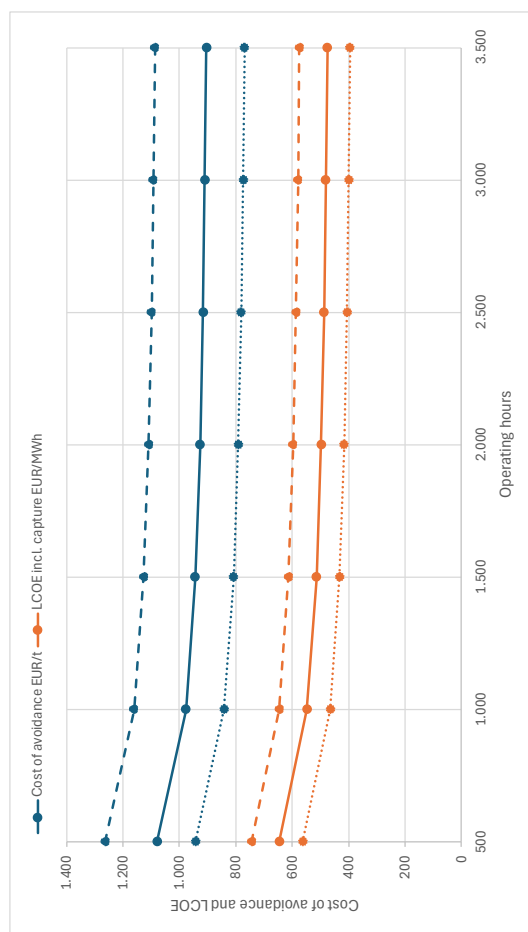
low case

Marginal cost	241	240	240	240	240	240
LCOE incl. capture EUR/MWh	452	377	352	340	332	327
Cost of avoidance EUR/t	696	599	567	551	541	534
Operating hours	500	1.000	1.500	2.000	2.500	3.000

high case

Marginal cost	360	359	358	358	358	358
LCOE incl. capture EUR/MWh	601	527	502	489	482	476
Cost of avoidance EUR/t	914	816	784	767	758	751
Operating hours	500	1.000	1.500	2.000	2.500	3.000

Application 3 Medium OCGT Blue Hydrogen



	mid		low		high	
Marginal costs	358	356	356	355	355	355
LCOE incl. capture	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh
Cost of avoidance	EUR/t	EUR/t	EUR/t	EUR/t	EUR/t	EUR/t
Operating hours	500	1,000	1,500	2,000	2,500	3,000
Marginal costs	292	291	291	290	290	290
LCOE incl. capture	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh
Cost of avoidance	EUR/t	EUR/t	EUR/t	EUR/t	EUR/t	EUR/t
Operating hours	500	1,000	1,500	2,000	2,500	3,000
Marginal costs	437	434	434	433	433	433
LCOE incl. capture	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh	EUR/MWh
Cost of avoidance	EUR/t	EUR/t	EUR/t	EUR/t	EUR/t	EUR/t
Operating hours	500	1,000	1,500	2,000	2,500	3,000

Results

IRR	%	21%
Pay back time	years	10
CO2 reduction	ktpa	637

LCOE approximation for

Cost component	Cost, EUR/MNP, EUR m	Share, %
Capex	15,92	55,05
Abandonment	0,15	0,52
Fuel	532,00	1.839,43
Other var opex	14,91	51,55
O&M and other fixed opex	9,09	31,44
Interest	0,00	0,00
Tax	2,86	9,87
Total (post-tax)	574,93	1.987,87
		100%

Total (pre-tax)	572,07	1.978,00
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Carbon reduction		
Nominal capture rate	%	100,0%
Effective capture rate	%	100,0%
Cost of avoidance		
LCOE Hydrogen	EUR/MWh	574.93
LCOENG	EUR/MWh	183.55 < Approximation
CO2 avoided	t/MWh	0.36
Cost of avoidance	EUR/t	1.087
Marginal costs	EUR/MWh	433

Application 4 Modern CC Blue Hydrogen

Results

IRR	%	22%
Pay back time	years	10
CO2 reduction	ktpa	1215

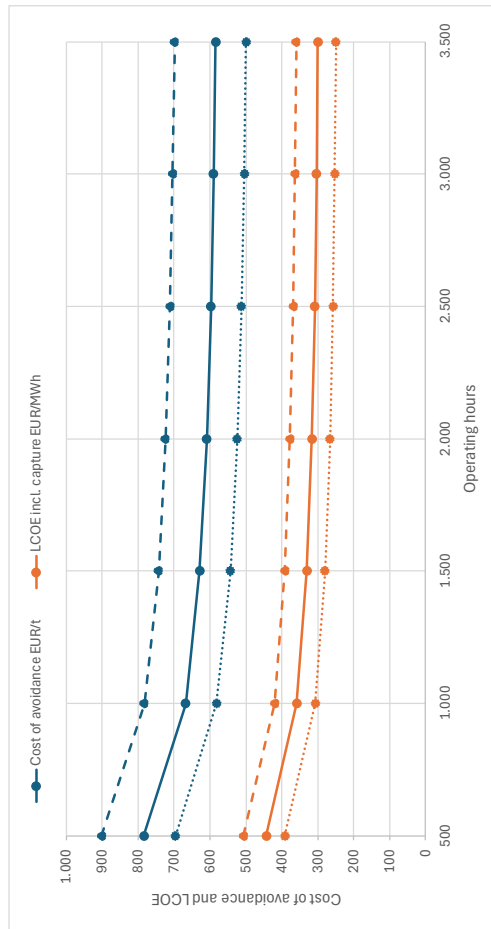
LCOE

Cost component	Cost, EUR/MM	NPV, EUR m	Share, %
Capex	9,22	102,04	3%
Abandonment	0,09	0,97	0%
Fuel	266,83	2,952,32	89%
Other var opex	8,20	90,70	3%
O&M and other fixed opex	13,35	147,72	4%
Interest	0,00	0,00	0%
Tax	2,01	22,23	1%
Total (post-tax)	299,70	3,315,98	100%
Total (pre-tax)	297,69	3,293,75	

LCOE NG

6,8
0,1
69,4
0,0
6,1
5,0
0,0
2,0

CO2 EUA costs



Carbon reduction

Nominal capture rate	%	100,0%
Effective capture rate	%	100,0%
CO2 avoided	EUR/MMWh	299,70
CO2 avoided	EUR/MMWh	89,38 < Approximation
CO2 avoided	t/MMWh	0,36
CO2 avoided	EUR/t	584
Marginal costs	EUR/MMWh	218

mid

Marginal costs	EUR/MMWh	226	221	220	219	218	218	218
LCOE incl. capture	EUR/MMWh	444	358	330	316	308	303	300
Cost of avoidance	EUR/t	784	667	629	609	598	590	584
Operating hours		500	1,000	1,500	2,000	2,500	3,000	3,500

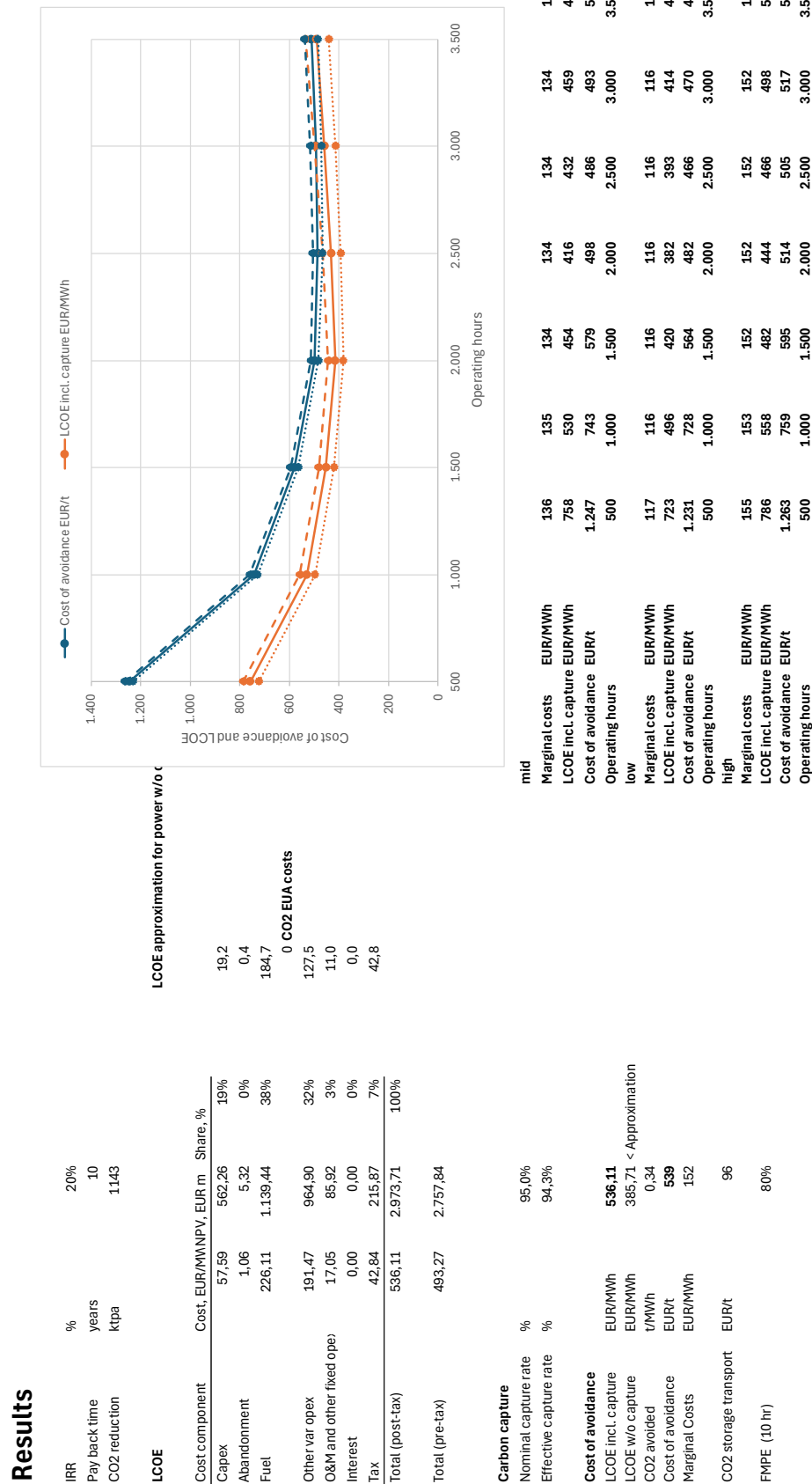
low

Marginal costs	EUR/MMWh	184	181	179	179	178	178	178
LCOE incl. capture	EUR/MMWh	391	307	279	265	257	252	249
Cost of avoidance	EUR/t	696	581	543	524	512	505	499
Operating hours		500	1,000	1,500	2,000	2,500	3,000	3,500

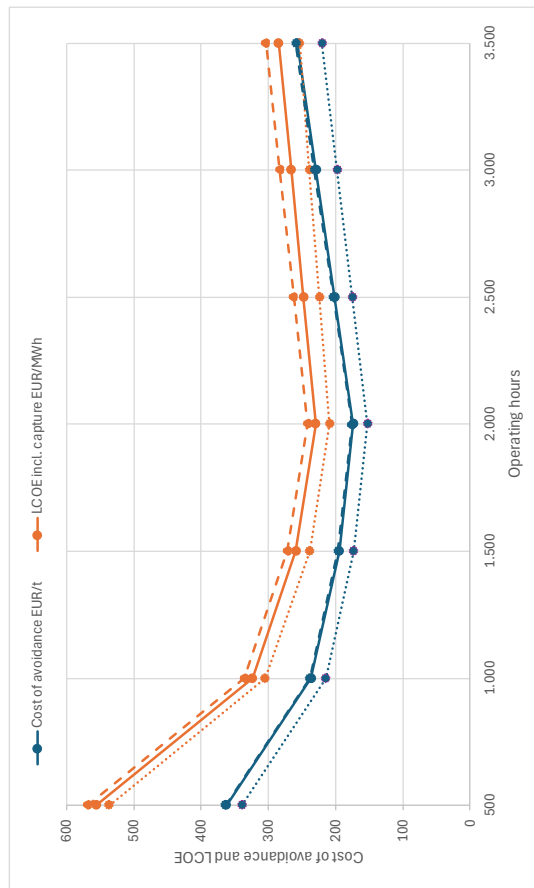
high

Marginal costs	EUR/MMWh	275	270	268	267	267	266	266
LCOE incl. capture	EUR/MMWh	507	420	391	377	369	363	360
Cost of avoidance	EUR/t	902	783	743	723	712	704	698
Operating hours		500	1,000	1,500	2,000	2,500	3,000	3,500

Application 5 Modern CC and CCS (realistic)



Application 6 USC 100% Biomass (realistic)



mid	Marginal costs	EUR/MWh	76	72	71	70	70	70	69
	LCOE incl. capture	EUR/MWh	556	324	259	229	248	266	284
	Cost of avoidance	EUR/t	362	236	194	173	201	229	256
	Operating hours		500	1,000	1,500	2,000	2,500	3,000	3,500
low	Marginal costs	EUR/MWh	61	58	57	56	56	56	55
	LCOE incl. capture	EUR/MWh	537	305	238	209	224	239	254
	Cost of avoidance	EUR/t	339	215	173	153	175	198	220
	Operating hours		500	1,000	1,500	2,000	2,500	3,000	3,500
high	Marginal costs	EUR/MWh	87	82	80	80	79	79	79
	LCOE incl. capture	EUR/MWh	569	336	271	242	262	283	304
	Cost of avoidance	EUR/t	364	238	196	175	203	231	259
	Operating hours		500	1,000	1,500	2,000	2,500	3,000	3,500

Results

IRR	%	20%
Pay back time	years	10
CO2 reduction	ktpa	897

LCOE

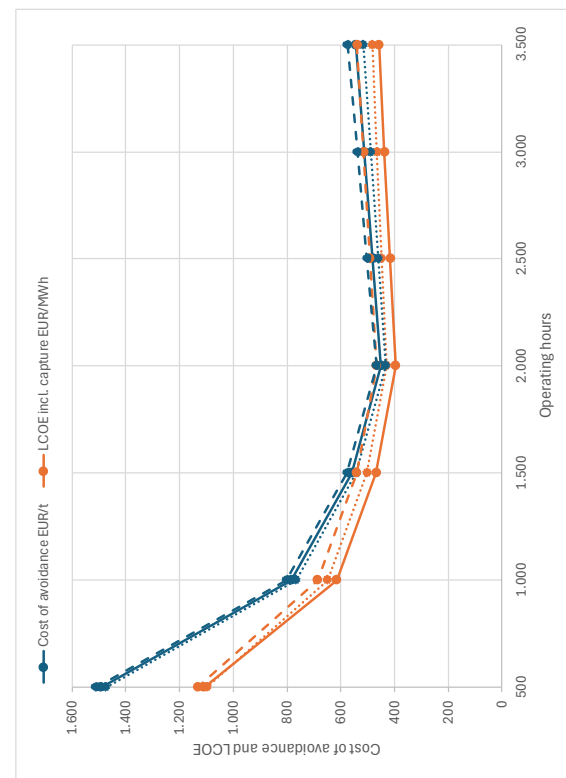
LCOE before

Cost component	Cost, EUR/MMNPV, EUR m	Share, %
Capex	75.66	457.25
Abandonment	0.72	4.33
Fuel	143.06	864.59
Other var opex	30.66	185.27
O&M and other fixed opex	38.52	232.80
Interest	0.00	0.00
Tax	14.92	90.19
Total (post-tax)	303.53	1,834.42
Total (pre-tax)	288.61	1,744.24

Biomass emission CO2

CO2 biomass	%	100.0%
Effective		85.0%
Cost of avoidance		
LCOE incl. Biomass	EUR/MWh	303.53
LCOE no Biomass	EUR/MWh	224.19 < Approximation
CO2 avoided	t/MWh	0.31
Cost of avoidance	EUR/t	259
Marginal costs	EUR/MWh	79
FMPE (10 hr)		
Average Peak price	EUR/MWh	75%

Application 7 USC with CCS (Realistic)



LCOE approximation for power w/o capture

Cost component	Cost, EUR/MW NPV, EUR m	Share, %
Capex	200,47	1.514,44
Abandonment	1,90	14,34
Fuel	61,81	466,93
Other var opex	84,24	636,38
O&M and other fixed opex	49,27	372,24
Interest	0,00	0,00
Tax	85,62	646,79
Total (post-tax)	483,31	3.651,12
Total (pre-tax)	397,89	3.004,33

Results

IRR	%	21%
Payback time	years	10
CO2 reduction	ktpa	1576

LCOE

Cost component	Cost, EUR/MW NPV, EUR m	Share, %
Capex	200,47	1.514,44
Abandonment	1,90	14,34
Fuel	61,81	466,93
Other var opex	84,24	636,38
O&M and other fixed opex	49,27	372,24
Interest	0,00	0,00
Tax	85,62	646,79
Total (post-tax)	483,31	3.651,12
Total (pre-tax)	397,89	3.004,33

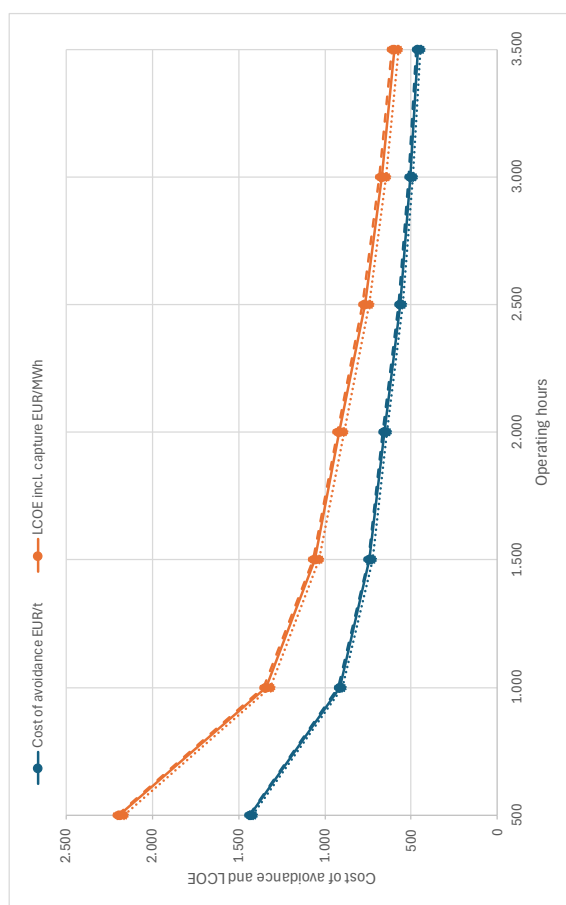
Carbon capture

Nominal capture rate	%	95,0%
Effective capture rate	%	91,9%
Cost of avoidance		
LCOE incl. capture	EUR/MWh	483,31
LCOE w/o capture	EUR/MWh	312,63 < Approximation
CO2 avoided	t/MWh	0,33
Cost of avoidance	EUR/t	516
Marginal Costs	EUR/MWh	163
CO2 transport / storage	EUR/t	96
FMPE (10 hr)		60%
Average Peak price	EUR/MWh	694

Mid

Marginal costs	EUR/MWh	178	176	175	175	175	175	175	175
LCOE incl. capture	EUR/MWh	1.110	615	469	396	417	437	458	458
Cost of avoidance	EUR/t	1.483	784	560	450	481	513	545	545
Operating hours		500	1.000	1.500	2.000	2.500	3.000	3.500	3.500
Low									
Marginal costs	EUR/MWh	166	164	163	163	163	163	163	163
LCOE incl. capture	EUR/MWh	1.100	649	503	430	448	466	483	483
Cost of avoidance	EUR/t	1.474	766	543	433	461	488	516	516
Operating hours		500	1.000	1.500	2.000	2.500	3.000	3.500	3.500
High									
Marginal costs	EUR/MWh	191	189	188	188	188	187	187	187
LCOE incl. capture	EUR/MWh	1.133	687	541	468	491	515	539	539
Cost of avoidance	EUR/t	1.512	802	578	468	503	539	575	575
Operating hours		500	1.000	1.500	2.000	2.500	3.000	3.500	3.500

Application 8 BECCS (realistic)



mid	255	255	255	255	255	255	255
Marginal costs	255	255	255	255	255	255	255
LCOE incl. capture	2,189	1,341	1,058	917	768	669	599
Cost of avoidance	1,432	914	742	655	565	504	461
Operating hours	500	1,000	1,500	2,000	2,500	3,000	3,500
low							
Marginal costs	232	232	232	232	232	232	232
LCOE incl. capture	2,163	1,315	1,032	890	743	644	574
Cost of avoidance	1,416	898	726	639	549	489	446
Operating hours	500	1,000	1,500	2,000	2,500	3,000	3,500
high							
Marginal costs	270	270	270	270	270	270	270
LCOE incl. capture	2,201	1,353	1,070	929	781	682	612
Cost of avoidance	1,439	921	749	663	572	512	469
Operating hours	500	1,000	1,500	2,000	2,500	3,000	3,500

Results

IRR	%	20%
Pay back time	years	10
CO2 reduction	ktpa	236

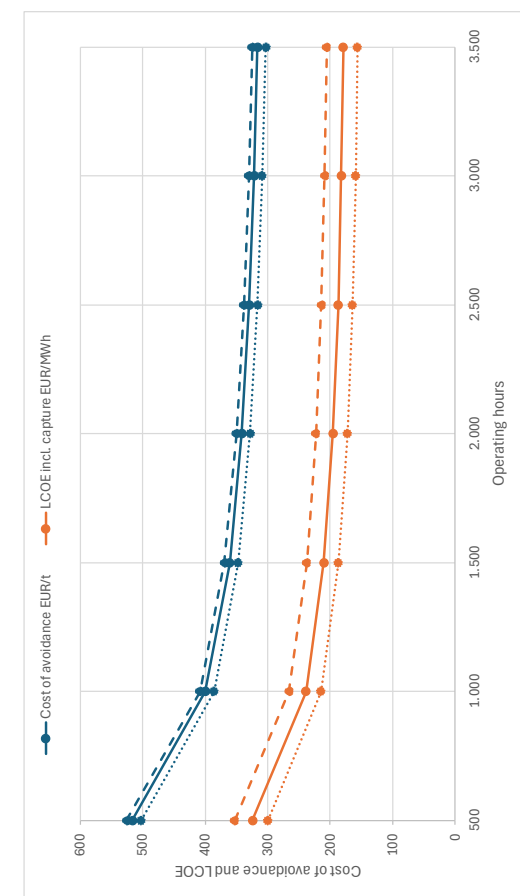
LCOE no references

Cost component	Cost, EUR/MNP, EUR m	Share, %
Capex	188,14	191,32
Abandonment	1,78	1,81
Fuel	136,03	138,33
Other var opex	205,19	208,66
O&M and other fixed opex	84,76	86,20
Interest	0,00	0,00
Tax	82,99	84,39
Total (post-tax)	698,88	710,72
Total (pre-tax)	615,90	626,33

Biomass emission CO2

Biomass	EUR/MWh	100,0%
Average Carbon intensity t/MWh	EUR/MWh	0,36
Average power price	EUR/MWh	85
Cost of avoidance		
LCOE incl. Biomass	EUR/MWh	614 - Approximation
LCOE no Biomass	EUR/MWh	0,07
CO2 avoided	t/MWh	1,64
Cost of avoidance	EUR/t	471
Marginal costs	EUR/MWh	270
CO2 transport / storage	EUR/t	96
FWPE	%	50%
Effective	%	100%

Application 9 Modern IGCC Bio-Syngas



Results

IRR	%	21%
Pay back time	years	10
CO2 reduction	ktpa	1215

LCOE NG

Cost component	Cost, EUR/MWNPV, EUR/m	Share, %
Capex	9,22	102,04
Abandonment	0,09	0,97
Fuel	173,17	1.916,00
Other var opex	8,25	91,24
O&M and other fixed ope	13,35	147,72
Interest	0,00	0,00
Tax	1,74	19,20
Total (post-tax)	205,81	2.277,17
Total (pre-tax)	204,08	2.257,97

CO2 EUA costs

6,8
0,1
69,1
0,0
6,2
5,0
0,0
1,7

Carbon reduction

Nominal capture rate	%	100,0%
Effective capture rate	%	100,0%
Cost of avoidance		
LCOE Hydrogen	EUR/MWh	205,81
LCOE NG	EUR/MWh	88,86 < Approximation
CO2 avoided	t/MWh	0,36
Cost of avoidance	EUR/t	325
Marginal costs	EUR/MWh	144

mid

Marginal costs	EUR/MWh	131	126	124	124	123	123	122
LCOE incl. capture	EUR/MWh	324	239	210	196	187	182	179
Cost of avoidance	EUR/t	516	400	361	341	330	322	316
Operating hours		500	1.000	1.500	2.000	2.500	3.000	3.500
low								
Marginal costs	EUR/MWh	112	108	106	105	105	105	104
LCOE incl. capture	EUR/MWh	300	215	187	173	165	159	156
Cost of avoidance	EUR/t	502	386	347	328	316	309	303
Operating hours		500	1.000	1.500	2.000	2.500	3.000	3.500
high								
Marginal costs	EUR/MWh	154	148	146	145	144	144	144
LCOE incl. capture	EUR/MWh	353	266	237	223	214	209	206
Cost of avoidance	EUR/t	526	409	369	350	338	330	325
Operating hours		500	1.000	1.500	2.000	2.500	3.000	3.500

Application 10 Modern CC Green Hydrogen

Results

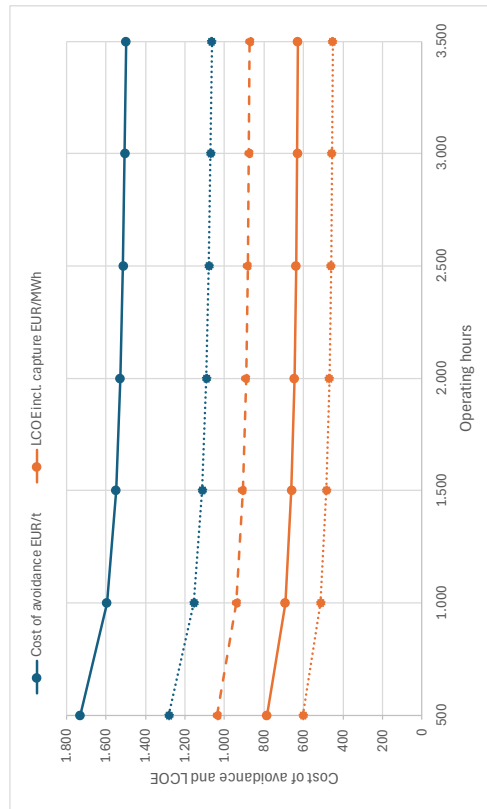
IRR	%	21%
Pay back time	years	10
CO2 reduction	ktpa	1215

LCOE

Cost component	Cost, EUR/MWh	NPV, EUR m	Share, %
Capex	9,22	102,04	1%
Abandonment	0,09	0,97	0%
Fuel	839,56	9,289,14	96%
Other var opex	8,20	90,70	1%
O&M and other fixed opex	13,35	147,72	2%
Interest	0,00	0,00	0%
Tax	1,69	18,73	0%
Total (post-tax)	872,11	9,649,31	100%
Total (pre-tax)	870,42	9,630,57	

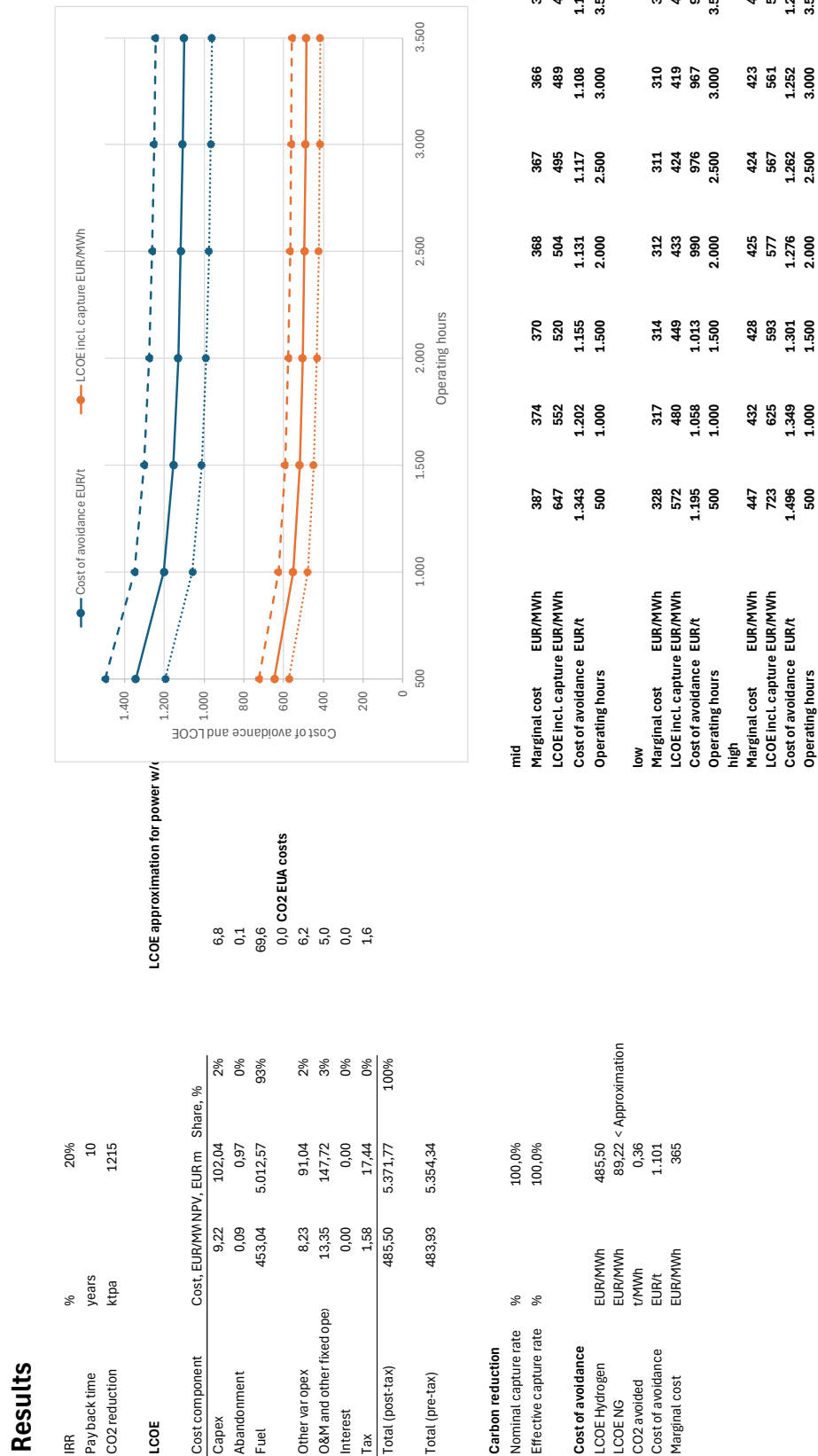
LCOE approximation for power w/o captu

6,8
0,1
89,2
0,0
6,1
5,0
1,7

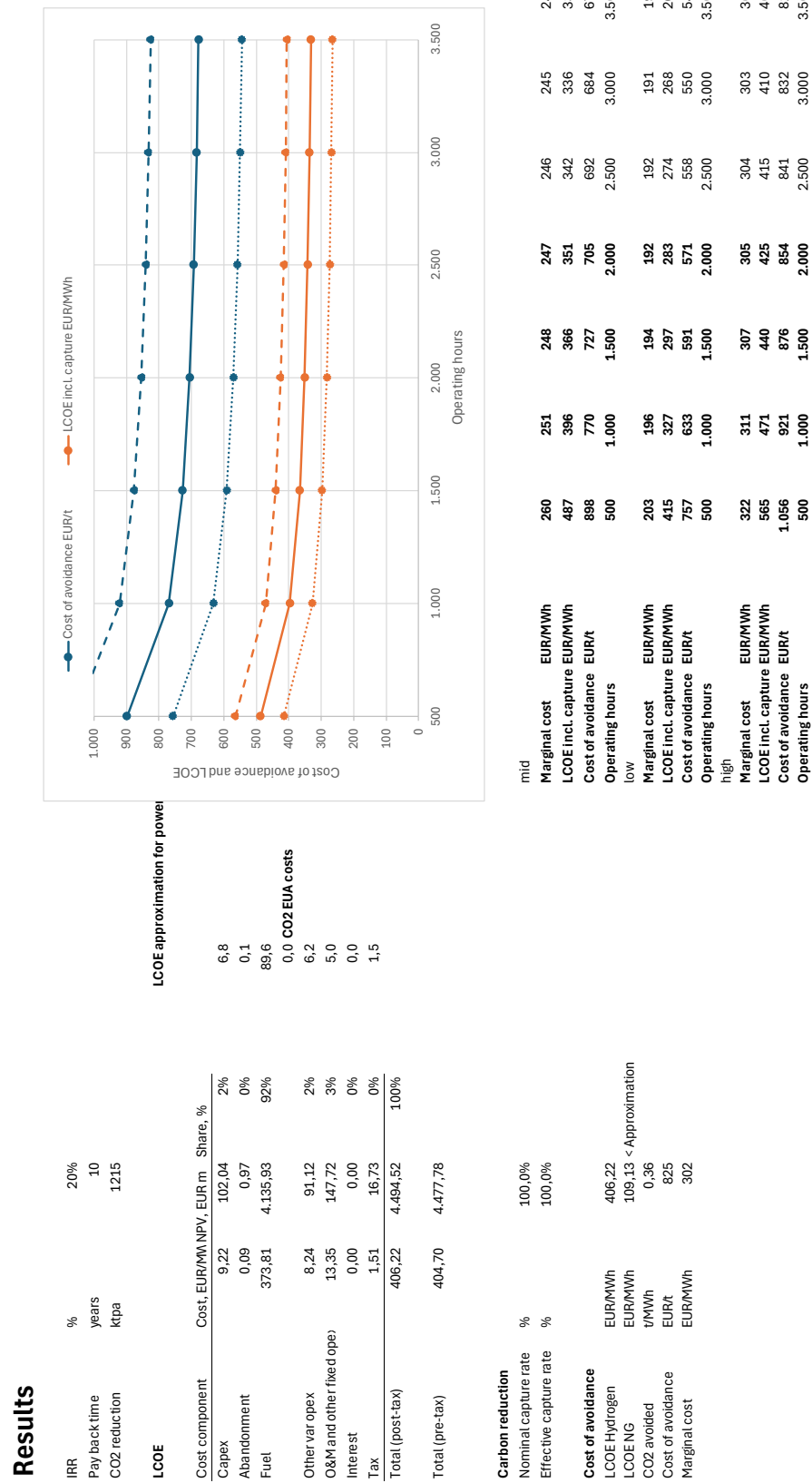


mid	Marginal cost	EUR/MWh	495	485	482	480	479	478
	LCOE incl. capture	EUR/MWh	784	692	662	646	632	628
	Cost of avoidance	EUR/t	1.731	1.595	1.549	1.527	1.504	1.498
	Operating hours		500	1.000	1.500	2.000	2.500	3.000
low	Marginal cost	EUR/MWh	351	344	341	340	339	339
	LCOE incl. capture	EUR/MWh	602	513	484	469	455	452
	Cost of avoidance	EUR/t	1.281	1.154	1.112	1.091	1.078	1.063
	Operating hours		500	1.000	1.500	2.000	2.500	3.000
high	Marginal cost	EUR/MWh	696	681	677	674	672	671
	LCOE incl. capture	EUR/MWh	1.037	940	907	891	882	876
	Cost of avoidance	EUR/t	2.375	2.226	2.177	2.152	2.137	2.120
	Operating hours		500	1.000	1.500	2.000	2.500	3.000

Application 11 Modern CC on Biobased Hydrogen



Application 12 Modern CC Hydrogen Produced from ammonia



Application 13

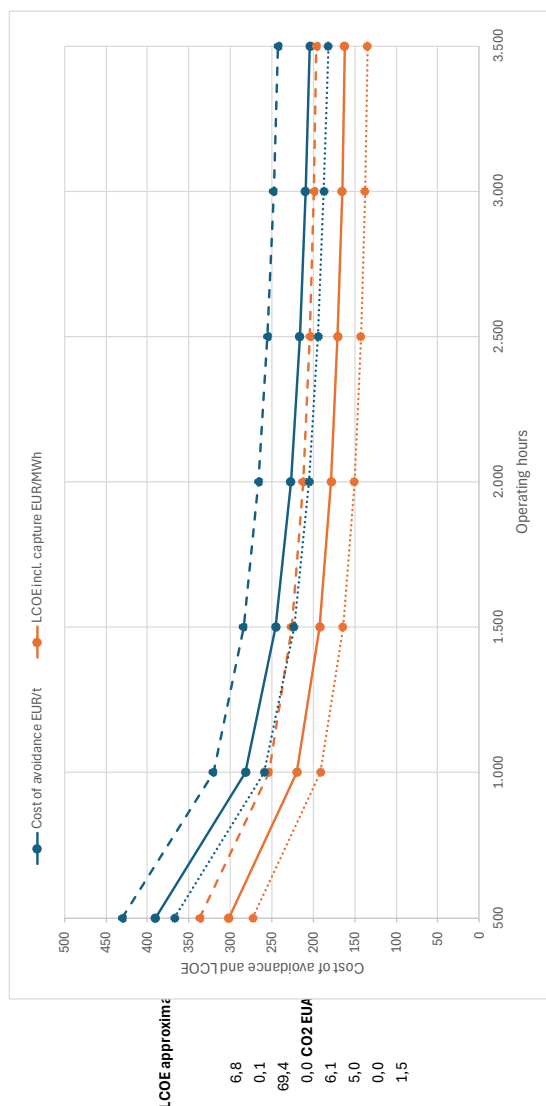
Results

	IRR	Pay back time	CO2 reduction
	%	years	ktpa
	20%	10	1215

LCOE	Cost component	Cost, EUR/MWh NPV, EUR m	Share, %
LCOE	Capex	9.22	102.04
	Abandonment	0.09	0.97
	Fuel	129.98	1,438.18
	Other var opex	8.20	90.70
	OM and other fixed opex	13.35	147.72
	Interest	0.00	0.00
	Tax	1.46	16.16
	Total (post-tax)	162.30	1,795.77
	Total (pre-tax)	160.84	1,779.61

Carbon reduction	
Nominal capture rate	100,0%
Effective capture rate	100,0%

Cost of avoidance		
LCOE Hydrogen	EUR/MWh	162.30
LCOE NG	EUR/MWh	88.83 < Approximation
CO2 avoided	t/MWh	0.36
Cost of avoidance	EUR/t	204
Marginal costs	EUR/MWh	109

[illegible]

Appendix C

Excel work books

Data sheet cost numbers



datasheet cost
numbers sent on 31 n

Hydrogen production costs



hydrogen production
costs.xlsx

Cash flow models (application 1 to 13)



13 Cash flow model
Modern Modern CC



12 Cash flow model
Modern Modern CC



11 Cash flow model
Modern Modern CC



10 Cash flow model
Modern Modern CC



9 Cash flow model
Modern Modern IGCC



8 Cash flow model
BECCS v7.xlsm



8 Cash flow model
BECCS v1 realistic.xlsm



7 Cash flow model
Modern USC convert



7 Cash flow model
Modern USC convert



6 Cash flow model
Modern USC convert



5 Cash flow model
Modern Modern CC



5 Cash flow model
Modern Modern CC



4 Cash flow model
Modern Modern CC



3 Cash flow model
Medium Simple GT cc



2 Cash flow model
Large Simple GT conv



1 Cash flow model
F-class CC convert to

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