6. Decarbonisation support in practice: case studies

This chapter presents the results of two case studies which illustrate the consequences of the current set of policy instruments for the financial viability of two representative decarbonisation projects identified as critical by the zero-emission scenario for the Dutch industry by 2050 (Chapter 3). The two projects are green hydrogen for ammonia production in the chemicals sector and CCS for hydrogen production by steam-methane reforming in the refinery sector.

The zero-emission scenario for the Dutch industry by 2050 described in Chapter 3 presents sector-specific technological pathways that would be compatible with full decarbonisation, while Chapter 5 presents a comprehensive analysis of the policy instruments currently in place to encourage the decarbonisation of the Dutch industry. In this chapter, two case studies are carried out in order to understand in practice the consequences of the current set of policy instruments for the financial viability of specific decarbonisation projects identified as critical in Chapter 3. Additional analysis of emerging technologies necessary for industry decarbonisation is carried out in Chapter 8.

The two selected case studies are: 1) green hydrogen for ammonia production in the chemicals sector; and 2) CCS for hydrogen production by steam-methane reforming (SMR) in the refinery sector. The chemicals and refineries sectors are the two largest CO_2-emitting sectors in the Dutch industry (Chapter 2). The case studies focus on hydrogen production, as this technology is expected to contribute the most to the low-carbon transition, accounting for more than 25% of emission reductions by 2050 (Chapter 3). It plays a significant role in the four sectors analysed in this report, but is of major importance in the chemical sector and for refineries. CCS represents more than 12% of the necessary emission reductions by 2050, and has applications in the chemical, metallurgical and refineries sectors because all three will remain partly reliant on fossil fuels in 2050 and, more generally, because it enables the production of blue hydrogen.

The two case studies also correspond to two different Technology Readiness Levels (TRL). Green hydrogen, based on electrolysis of water fuelled by renewable electricity, is an immature technology that still requires significant cost reductions, which could be brought about by research and development as well as through learning-by-doing and scale economies. Green hydrogen production also requires large amounts of renewable electricity, which is not yet available in the Netherlands. In comparison, blue hydrogen – a combination of CCS and steam-methane reforming (SMR) – is a fairly mature technology that can be deployed relatively soon and can enable the uptake of hydrogen as an energy carrier, but leads to direct abatement as well, by replacing current hydrogen production via grey steam-methane reforming.

The two projects are analysed from the perspective of a fictive firm that seeks to implement a carbon-reducing project and undertakes an assessment of its potential viability under the current policy landscape, which includes pricing mechanisms that discourage carbon emissions and also the various public subsidies that can potentially be requested. For each project, information is collected on the required amount of capital and the operational costs (under different energy price scenarios) and an assessment is made on the eligibility to various support mechanisms and the likelihood of obtaining the subsidies. The final objective is to assess whether the implementation of the projects is dependent on obtaining public subsidies.

6.1. Case Study 1: Green hydrogen in ammonia production

6.1.1. Introduction

Ammonia is an important feedstock for fertilisers and its production is currently the most energy-intensive process in this industry.[1] To produce ammonia (NH_3), nitrogen (N_2) and hydrogen (H_2) are required. The production of ammonia currently represents 43% of global hydrogen demand. Most of the remaining demand relates to oil refining into fuels and basic commodities, with 52% of global hydrogen demand (IEA, 2019[1]).

Currently, ammonia-producing plants use natural gas-based steam-methane reforming (SMR) for hydrogen production on site, a CO_2-emitting process because methane is used both for energy production and as feedstock. An option for sustainable ammonia production is to use electrolysis from renewable resources for hydrogen production. Electrolysis is the process by which electricity is used to split water into hydrogen and oxygen. This reaction takes place in a unit called an electrolyser. Electrolysers can range in size from small, appliance-size equipment that is well-suited for small-scale distributed hydrogen production, to large-scale, centralised production facilities that could be tied directly to renewable or other non-greenhouse-gas-emitting forms of electricity production.[2] If the electricity production is renewable, this process is called green hydrogen production.

According to Berenschot, the plausible technological pathway for ammonia production is based on a combination of green hydrogen and auto-thermal reforming with CCS (blue hydrogen, with an assumed carbon capture rate of 85%). A major determinant of the growth of green hydrogen is the amount of renewables in the Dutch energy mix. For ammonia production at sites that are connected to offshore wind farms, green hydrogen from electrolysis is a logical route. Electricity can then be used to produce the nitrogen with air separation units and to supply the compressors for the Haber-Bosch process. According to Berenschot, a total of 115 PJ of hydrogen will need to be produced on sites in 2050, which requires either 175 PJ of electricity supply for green hydrogen, or 115 PJ of natural gas and 30 PJ of electricity for blue hydrogen.

The Netherlands is the second largest hydrogen producer in Europe after Germany, producing an estimated volume of around 10 billion cubic metres per year.[3] According to *Fertiliser Netherlands* (Meststoffen Nederland), the Dutch ammonia market consists of four players: Yara (Sluiskil), OCI Nitrogen (Chemelot), Rosier (Sas van Gent) and ICL fertilisers (Amsterdam & Heerlen).[4] The sites in Amsterdam, Sas van Gent and Sluiskil are not land-locked and should soon have access to electricity from offshore wind. Therefore, these sites have the option to produce green hydrogen on site from electrolysis, because of the close proximity to offshore wind power.

Ørsted (the developer of the Borssele wind farm project) and Yara recently announced a plan to produce 75 000 tonnes of “green ammonia” per year at Yara’s existing Sluiskil plant in the Netherlands. To realise this ambition, Yara intends to install a 100 MW electrolyser, which would be run using Ørsted’s offshore wind energy (capacity 752 MW[5]). The final investment decision is expected in 2021-22, and production would begin in 2024-25.[6] This 100 MW electrolyser project will serve as the first case study.

The case study is potentially replicable to other sites in the Netherlands, provided that abundant renewable electricity supply is available and that a large electricity connection is established. For example, the electricity connection at OCI is currently limited to 12 MW[7] and the sites in Heerlen and Chemelot have less access to renewable electricity, requiring infrastructure adjustments to be made as a prerequisite for similar projects.

6.1.2. Case study characteristics

Yara Sluiskil produces around 5 million tonnes of fertiliser products per year. The three ammonia plants (‘C’, ‘D’ and ‘E’) use natural gas to produce ammonia and have a combined production capacity of approximately 1.8 million tonnes of NH_3 per year (Table 6.1) requiring about 0.22 million tonnes of hydrogen (Batool and Wetzels, 2019[2]).

Table 6.1. Overview of annual production and emissions of Yara ammonia plants

Yara	Estimated production capacity (kt/a)	CO_2 emissions 2017 (kt/a)
Ammonia plant C (1973)	449	793
Ammonia plant D (1984)	639	1 221
Ammonia plant E (1988)	731	1 128
Total	1 820	3 142

Note: Estimated production benchmark for year 2009
Source: PBL.

A 100 MW electrolyser can produce around 50 tonnes of hydrogen per day,[8] amounting to approximately 18 kt of hydrogen annually. With this production capacity of hydrogen, a back of the envelope calculation ($N_2 + 3 H_2 \rightarrow 2 NH_3$) shows that the potential ammonia production capacity is 100 kt annually.

How much carbon emissions would this project abate? According to PBL, Yara's ammonia plant C, the oldest and least efficient plant on the site, produces 449 kt of ammonia per year, leading to 793 kt of CO_2 emissions (Table 6.1). The substitution of 100 kt of production from plant C with green hydrogen would thus result in an abatement of (793*100/449=) 177 kt of CO_2, which should however be adjusted downward because some energy is used for pressurising. Similarly, the Ammonia Energy Association states that a 100 MW electrolyser would reduce Yara's CO_2 emissions by about 5%,[9] or 180 kt CO_2, considering the emissions of 3.6 million tonne CO_2 in 2017. Finally, Praxair, one of the world's largest hydrogen producers, reports that the carbon footprint for conventional (SMR) hydrogen production is 9.3 kg CO_2/kg H_2, leading to 167 kt (18*9.3) for our system.[10] Hence, we assume that with this project Yara can abate 160 – 180 kt CO_2 annually.

Although electrolysers are a mature technology, the significant scale of the hydrogen project of Yara is new. Three types of electrolysers exist: Alkaline Water Electrolysis (AWE), proton-exchange membrane cell (PEM) and solid oxide electrolysis cell (SOEC) (Grigoriev et al., 2020[3]). Of the AWE type, installations up to the MW scale are commercially available; of the PEM type, on the multi-MW scale; and of the last type, no installation is commercially available yet, only demonstration projects at lab scale (around 200 W). The AWE technology is the cheapest regarding CAPEX (EUR 700-800/kW), while the PEM has higher CAPEX (EUR 1 000-1 500/kW) but significant progress has been made over the past few years. For both the AWE and PEM, the OPEX is 2% of the CAPEX annually for a 20 MW installation, (Table 6.2).

Table 6.2. Expected costs and other technicalities of electrolyser types

Technology		Alkaline		PEM	
	Unit	2017	2025	2017	2025
Efficiency	kWh of electricity/kg of H_2	51	49	58	52
Efficiency (lower heating value)	%	65	68	57	64
Lifetime Stack	Operating hours	80 000	90 000	40 000	50 000
CAPEX – total system costs (incl. power supply and installation costs)	EUR/kW	750	480	1200	700
OPEX	% of initial CAPEX/year	2	2	2	2
CAPEX – stack replacement	EUR/kW	340	215	420	210
Typical output pressure	Bar	Atm.	15	30	60
System lifetime	Years	20		20	

Note: CAPEX and OPEX are based on a 20 MW system.
Source: Grigoriev et al. (2020[3]).

One hundred MW scale systems are under development. Large-scale implementation of electrolysis technologies still requires cost reductions; nonetheless, investments are being made towards the development of macroscale power-to-gas and breakthroughs in related fuel technologies facilitate cost reduction down to the target of EUR 500/kW. Indeed, OCI Nitrogen has estimated that a large-scale electrolysis pilot unit of 100 MW requires an investment of EUR 50 million.[11] Moreover, PBL uses EUR 525/kW for the electrolyser CAPEX (comparable with Grigoriev et al. (2020[3])) and estimates the OPEX to amount for 3% of the CAPEX (50% higher than Grigoriev et al. (2020[3])). The PBL estimates imply a CAPEX of EUR 52.5 million and an annual OPEX of EUR 1.5 million. This is in the same order of magnitude as Grigoriev et al. (2020[3])., therefore we assume CAPEX to be EUR 50-75 million, based on the PBL, OCI estimate and 2017 alkaline costs of Grigoriev et al. (2020[3]).

In the Netherlands, other hydrogen-related projects are currently being developed. Topsector Energie reports four other projects with a cost specification. In particular, a feasibility study for the HyNetherlands Eemshaven project (a 100 MW electrolyser) projects a CAPEX of EUR 50-100 million. Two other projects, H2ermes and H2.50, are in the phase of conducting a front end engineering design (FEED) study and estimate the CAPEX to be EUR 150 million and EUR 225-300 million for a 100 MW and 250 MW electrolyser project, respectively. The realisation of DJewels, a 20 MW electrolyser, specifies a EUR 16 million subsidy, but the total project costs are unknown.[12] Therefore, the order of magnitude of the costs are in line with the assumptions above. However, it is clear that the construction phase is really the last phase of the projects, which should include development costs and a possible FEED study. In this case study, a development study is assumed to amount to EUR 25-30 million, as calculated by the European Commission[13].

Finally, the lifetime of an electrolyser is estimated to be 80 000 hours, both by PBL and Grigoriev et al. (2020[3]). In a situation where the plant operates 24/7, it runs for 8 000 hours annually. Therefore, the installation depreciates in ten years (it is unknown whether there is residual value). It can reasonably be assumed that Yara would want to run the electrolyser full-time, as hydrogen supply is critical for the ammonia production supply chain. A situation where the installation acts as a balancing method of electricity supply would imply discontinuous hydrogen production. Then, either the ammonia production becomes discontinuous itself, or SMR hydrogen production should act as swing supply while emitting the corresponding greenhouse gases. The benefit of acting as a balancing method is cost reduction, because the electricity price is lower in times of 'over' supply. For the sake of simplicity, we assume that Yara favours a continuous production.

A summary of the ammonia production quantities, abated emissions, costs and electricity consumption is given in Table 6.3.

Table 6.3. Overview of case study characteristics

Case study characteristics	Quantity
Total annual production ammonia at Yara	1820 kt
Ammonia production of 100 MW electrolyser	100 kt
Emission abatement 100 MW electrolyser	160 - 180 kt CO2
CAPEX 100 MW electrolyser	50 - 75 EUR mln
OPEX 100 MW electrolyser	1.5 EUR mln/a
Development study	25-30 EUR mln
Lifetime 100 MW electrolyser	80.000 h (~ 10 year)
Electricity consumption 100 MW electrolyser	0.8 TWh/y
Natural gas savings 100 MW electrolyser	0.52 TWh/y
SMR OPEX savings	3 EUR mln/y

6.1.3. Policy instrument analysis

The construction of a 100 MW electrolyser can best be regarded as a pilot or demonstration project with a prior R&D component (FEED study). However, the SDE++ instrument – aimed at scaling up projects with the highest TRLs – also mentions green hydrogen in its call for tenders. Therefore, in this analysis all policy instruments will be considered, from R&D support to SDE++, in addition to the possible savings from the EU ETS, the Carbon Levy and energy taxes.

Research, Development and Demonstration Instruments

H2020 (Innovation Action, deadline 26 January 2021, single stage)

There is a special call from the European Commission to develop and demonstrate a 100 MW electrolyser.[14] The case study seems like an excellent example of a project that can respond to this call, as the operation in an industrial environment like a fertiliser production plant is mentioned explicitly. The EU proposes a contribution of EUR 25–30 million and support can be combined with other European or national financing instruments. In return for the funds, mandatory knowledge sharing is required, as is an evaluation of the project and its environmental impact. A list of expected technological impacts is presented, including reducing the electrolyser's CAPEX to EUR 480/kW. This is more ambitious than the estimates above, implying that a development study is required.

Innovation Action projects are typically assessed on two criteria: excellence and impact.[15] Because this is a special call, the excellence (technological impact) is already prescribed. Projects thriving for even higher efficiencies have higher chances of winning the subsidy, but this is not expected before 2025 based on Grigoriev et al. (2020[3]). Regarding the impact criterion, the electrolyser at the fertiliser plant has a direct impact on emissions, and could induce knowledge spillovers. To conclude, Yara's project is very likely eligible for the EUR 25-30 million subsidy, but it is unknown exactly how much competition there is for the grant.

WBSO

The WBSO is a tax credit on R&D expenditures, which are included in the first stages of the project. It consists of two parts, a fiscal deduction mechanism for R&D labour and prototype costs which do not have commercial value.[16] The fiscal deduction mechanism for labour costs amounts to 40% for the first EUR 350 000 and 16% above. The tax deduction is 100% for prototype costs. Yara is actively engaged in R&D activities[17], and could use their R&D personnel to work on the development study. If we assume that 80% of the development costs are labour costs and 20% prototype costs, EUR 8.2-9.8 million could be deducted, using the 16% rate.

MOOI (Mission-driven Research, Development and Innovation) under Topsector New Gas

As the name suggests, this policy instrument focuses on (industrial) research and development. The scheme excludes prototype/pilot activities, but includes development and FEED studies. Hence, the development part of the project is eligible. Moreover, green hydrogen and the development of a 100 MW electrolyser are explicitly mentioned as one of the missions[18] (MMIP 8), although it says "the road map pleads for green sustainable hydrogen but acknowledges that grey hydrogen in the short run and blue hydrogen in the middle run can help with its development". A total of EUR 17 million is available for industry, with a single project cap of EUR 4 million "for industrial research, experimental development or a feasibility study carried out by a consortium of at least three companies" and EUR 350 000 for 'other' project costs. The size of the project must be at least EUR 2 million and 50% of the development costs can be incurred.

Although the project is fully eligible (if it is developed by Yara together with at least two other companies), the cap of EUR 17 million shows that no more than four projects in the largest category can be supported. The ranking criteria are "meeting a mission", "quality of partnership/ consortium", "innovation level (with a system-level emphasis)", "success chance in Dutch market and society" and "quality of the project plan". If a project of the same type scores higher, the proposal will be rejected, even though it might score higher than other projects, to ensure a diversified subsidy portfolio. Therefore, whether or not the project could receive the subsidy depends on the degree of competition in the programme call.

Nationaal Groeifonds (development, infrastructure and innovation)

The funds concentrate on the growth of the national economy and creating public value and will allocate EUR 20 billion over five years.[19] Although an electrolyser technology can be applied across the fertiliser industry and across multiple sectors, potentially creating public value through knowledge spillovers, the project integrated into Yara's business, is an on-site innovation and does not imply direct growth of Dutch GDP. Examples of eligible projects that are regarded to create public value more directly are the Amsterdam metro line expansion and adaptations to the current gas network to create a hydrogen backbone.[20] Moreover, projects falling under other subsidy schemes are not eligible[21]. Therefore, this project is unlikely to be eligible to receive funds from the Nationale Groeifonds.

Demonstration Energy and Climate Innovation

The DEI+ supports pilot- and demonstration projects that contribute to cost-effective greenhouse gas abatement.[22] A project can be either a pilot or a demonstration project. Pilot or experimental development projects can apply for a direct subsidy of 25% and demonstration projects for 40% with a maximum of EUR 15 million, where the eligible amount is the additional costs of the climate-friendly investment in comparison with a similar non-climate friendly investment. The difference between a pilot project and a demonstration project is the practical application: while a pilot project focuses on testing, the aim of a demonstration project is to be commissioned and built. Both project types must have an experimental character and demonstrate the working of a new technology beyond lab conditions, such that the innovation can be brought to the market. Because this instrument is meant to develop and demonstrate technologies, projects should have a size no larger than strictly necessary, according to an expert interview from RVO. This categorisation leads to some ambiguity for this project, because part of the project, the development study, focuses on the development of a new technology, while the construction of a 100 MW electrolyser demonstrates this technology on a new scale. After consultation with the expert from RVO, it was concluded that only the development study for this project is eligible to the subsidy, because that part of the project focuses on innovation.

Three important grant criteria are: 'sufficient' abatement (cost-effectiveness), sufficient chance of success for the innovation in the Dutch market, and repetition potential. This project arguably scores less on the first criterion (although blue hydrogen projects are exempted), but well on the second and third. Nevertheless, the instrument works on a first come first serve basis, thus if the criteria are sufficiently fulfilled the subsidy should be granted.

Finally, among the categories of eligible project types for the DEI+, the category "flexibilisation of the electricity sector including hydrogen" explicitly mentions green hydrogen pilots where the resulting hydrogen may be used as feedstock for the industry. Hence, we assume that the project is eligible for a subsidy amounting to 25% of the costs of the development study, or EUR 6.25-7.5 million.

HER+

The explicit aim of the HER+ is to reduce future subsidy expenditures under the SDE++ scheme by investing in innovative projects that bring about cost-efficient emission reductions.[23] Hence, a leading criterion is that the future savings should outweigh the requested subsidy. HER+ is focused on demonstrating new technologies that are not yet close to the market, as opposed to DEI+. Still, the subsidy savings should be realised before 2030. The instrument works on a first come first served basis. Because the development of a large scale electrolyser does not reduce renewable electricity production costs, nor is in the list of 'regulation designation categories of sustainable energy production'[24], the project is likely not eligible. Furthermore, if green hydrogen would be eligible due to the (recent) inclusion of green hydrogen in the SDE++ scheme, and subsequent inclusion in the HER+, this project is unlikely to cause the potential future requested SDE++ subsidy to drop beyond the current cap of EUR 300/tCO_2. According to PBL, the current subsidy intensity for green hydrogen is EUR 1 064/t CO_2[25], and the project cannot be expected to reduce the costs by as much as EUR 765/t CO_2. Therefore, it is most likely not eligible to HER+.

Summary on RD&D instruments

Table 6.4 gives an overview of the RD&D policy instruments to which the electrolyser is eligible and the corresponding amount of the potential subsidy. All these instruments would subsidise the project's development study.

Table 6.4. Overview of RD&D subsidies to which the project's development study is eligible

Instrument	Amount Estimate
H2020 IA	EUR 25-30 mln
WBSO	EUR 8.2-9.8 mln
MOOI	EUR 4.35 mln
DEI+ (pilot)	EUR 6.25-7.5 mln

Deployment instruments

VEKI

VEKI is targeted at SMEs, hence Yara is not eligible.

Mia/Vamil

The project's technology must be on the *milieulijst*, which is not the case for the 100 MW electrolyser.

EIA

To be eligible the project must be on the *energielijst*. While power to hydrogen gas is on the list, installations for the purpose of feedstock production are excluded. Hence, the project is not eligible.

SDE++

The SDE++ is the largest Dutch policy instrument for deployment of low-carbon technologies and is similar to a contract-for-difference. The electrolyser in this case study is eligible, as hydrogen production by electrolysis is explicitly mentioned under the category "low CO_2 production".

However, the SDE++ is granted by tender. One of the criteria of subsidy for the SDE++ is the cost-effectiveness of CO_2 reductions. However, PBL estimates that hydrogen production by electrolysis requires a subsidy intensity of EUR 1 064/t CO_2, which is second to last in the cost-effectiveness ranking of various technologies for decarbonisation. Therefore, such a project will likely not be eligible for subsidy if the total requested subsidy of competing projects is larger than the allocated budget. This is acknowledged by the Minister of Economic Affairs and Climate in his letter to the parliament[26]. He writes: "From the broader perspective of the transition towards 2050, the development and timely start of hydrogen infrastructure and production scale-up is crucial to contribute to abatement after 2030" and "Although green hydrogen production is a relatively expensive option with respect to other techniques, I open this category to offer market parties the required perspective on the SDE++. Parties that run upfront – because of favourable conditions and/or other subsidies – can, in the meantime, be eligible for the SDE++ for the maximal subsidy amount of EUR 300/tCO_2. In that case the SDE++ covers part of the economic difference and other income (European or regional subsidy), lower costs (cheap installation of current) or a lower result covers the resulting amount." Furthermore, the Minister points to the hydrogen vision of the cabinet, published 30 March 2020.

In this vision, it is acknowledged that green hydrogen will not be able to compete in the SDE++, and hence "presents a new, temporary, instrument for exploitation support with the purpose of scaling up and reducing costs of green hydrogen production".[27] The government will allocate approximately EUR 35 million a year for this purpose by reallocating part of the existing funds for hydrogen pilots within the DEI+.

To conclude, green hydrogen projects are eligible for a support of EUR 300 per tonne of avoided CO_2, for 2 000 hours per year, but it remains ambiguous whether some of the SDE++ budget will be reserved for hydrogen projects. If this amount is not reserved, it is highly unlikely that a green hydrogen project will receive funds due to the low cost-effectiveness, until substantial cost reductions are achieved. The total eligible amount for this project would be EUR 12-13.5 million, based on the abatement of 160-180 kt CO_2 and taking into consideration that the subsidy is granted for a maximum of 2000 hours per year instead of 8000 hours.

Market-based instruments

ETS/Carbon Levy

Because the new Carbon Levy is coupled with the ETS, the two instruments are discussed together. The CO_2 levy is a baseline-and-credit system, where emissions above the baseline are taxed, and emissions below the baseline can be traded. The benchmark is set at the 2008 carbon efficiency and decreased by 0.2% per year to 2023 (i.e. the 2008 benchmark - 3% in 2023), the annual reduction factor starts at 1.2 and decreases by 5.7 percentage points per year until 2030. In 2021, the levy starts at EUR 30 /t CO_2, increases each year by EUR 10.56 /tCO_2 up to EUR 125 /tCO_2 in 2030. The ETS price of the previous year is subtracted from the levy. Yara is subjected to the tax and receives dispensation rights (1 DPR = 1 tonne of CO_2). Although the exact amount of dispensation rights (DPR) is unknown, it is given by the product of the activity level, the EU ETS benchmark and the reduction factor.

Using the (preliminary) EU ETS benchmark in 2008 (1.46 tCO_2/tNH_3),[28] accounting for the annual tightening, and assuming a constant production level of 1 820 t NH_3 (2009), the expected DPR for 2021-30 is given in column 2 of Table 6.5. EU ETS free allowances are granted based on the EU ETS benchmark and the plant's output. Since we assume that the plant will generate the same output with or without the electrolyser, the EU ETS free allowances are received in both cases and cancel out, so they do not have to be considered in this exercise.

Table 6.5. Effects of the carbon levy on the electrolyser project

Year	Reduction factor (CE Delft)	Expected DPR (kt CO_2)	Benchmark tCO_2/tNH_3 (2008)	Activity ammonia (2009) (kt NH_3)	CO_2 price (EUR/t CO_2)	Expected emission BAU (kt CO_2)	Expected penalty BAU (EUR)	Expected emissions 100 MW (kt CO_2)	Expected penalty 100 MW (EUR thsd)	Penalty Difference (EUR thsd)
2021	1.2	3 106	1.422	1 820	30.00	3 140	1 028	3 140	1 028	0
2022	1.14	2 944	1.419	1 820	40.56	3 140	7 934	3 140	7 934	0
2023	1.09	2 809	1.416*	1 820	51.12	3 140	16 897	3 140	16 897	0
2024	1.03	2 655	1.416	1 820	61.68	3 140	29 927	2 980	20 058	9 869
2025	0.97	2 500	1.416	1 820	72.24	3 140	46 222	2 980	34 664	11 558
2026	0.92	2 371	1.416	1 820	82.80	3 140	63 650	2 980	50 402	13 248
2027	0.86	2 217	1.416	1 820	93.36	3 140	86 205	2 980	71 268	14 938
2028	0.8	2 062	1.416	1 820	103.92	3 140	112 027	2 980	95 400	16 627
2029	0.74	1 907	1.416	1 820	114.48	3 140	141 115	2 980	122 798	18 317
2030	0.69	1 778	1.416	1 820	125.04	3 140	170 246	2 980	150 240	20 006

Note: where the 100 MW electrolyser is operational in 2024 and abates 160 kt CO_2. Note the BAU scenario is stationary, which is an unlikely representation of business activity, but useful for comparison with the case study, where, apart from the installation of a 100 MW electrolyser a stationary scenario is assumed. *New benchmark values will be established by the EU in 2021 and used from 2023 onwards.

When the carbon levy price is known, the expected carbon 'penalty' paid for the BAU scenario and for the '100 MW scenario', where Yara installs a 100 MW electrolyser which is fully operational in 2024, can be estimated. Both scenarios have to be considered as illustrative, as they are based on 2017 emissions by Yara. For the analysis of this case study however, the difference between the BAU and 100 MW scenario suffices. The aggregate amount of savings between 2020 and 2030 upon installing a 100 MW electrolyser with 160 kt CO_2 annual abatement is EUR 105 million (abstracting from discounting).

REB (Energy Tax) and ODE

The REB and ODE are the energy and electricity taxes, which Yara is subject to. According to Berenschot (2020[4]), the consumption factor of electricity to natural gas for hydrogen production is 175:115. A 100 MW electrolyser operating 8 000 h per year consumes 0.8 TWh/y and hence saves approximately 0.52 TWh/y (2.9 PJ/y) of natural gas, or 50 million Nm^3/y of natural gas.[29] An intensive analysis goes beyond the scope of this case study, therefore we take a constant electricity and natural gas price, based on a study of energy and electricity price scenarios for power to ammonia from CE Delft.[30] Two scenarios are described: a low price scenario and a high price scenario where the natural gas price is EUR 20/MWh and EUR 30/MWh and the electricity price is EUR 40/MWh and EUR 60/MWh, respectively. The tariffs for the REB+ODE are 2.36 eurocent/m^3 of gas (=0.23 eurocent/kWh) and 0.05 eurocent/kWh of electricity in 2022.[31] There is a significant reduction of 2.24 eurocent/kWh when exceeding 10 GWh annual consumption, but we assume Yara already exceeds 10 GWh annual consumption without the electrolyser. Four scenarios arise: a low and a high price scenario for both the BAU and 100 MW scenarios. Again, we only take into account the production of 100 kt ammonia. The annual energy expenditures including energy taxes are shown in Table 6.6. These calculations show that the additional electricity expenditures greatly exceed the OPEX of EUR 1-1.5 million as proposed by PBL and Grigoriev et al. (2020[3]). The additional annual operational expenditures in terms of feedstock for the 100 MW electrolyser is EUR 20.8-31.6 million depending on the price of electricity.

Two notes regarding the electricity expenditures need to be made. Firstly, through a contract with Ørsted, Yara might reduce the strike price to below the market price given the security of supply. Secondly, electricity expenditures might be reduced by not producing continuously, but 'flexibly'. Because the electricity price is expected to increase in volatility upon enlarging the renewable electricity share, the cost reduction might be significant, but would result in discontinuous production and a lower output.

Table 6.6. Annual energy expenditures for the production of 18 kt hydrogen as feedstock for the production of 100 kt of ammonia

	Annual energy consumption for 18 kt hydrogen production in TWh (gas, electricity, respectively)	Price (EUR/MWh)	Tax (EUR/MWh)	Total (EUR mln)
BAU – low energy price	0.52	20	2.3	11.6
BAU - high energy price	0.52	30	2.3	16.8
100 MW - low energy price	0.80	40	0.5	32.4
100 MW - high energy price	0.80	60	0.5	48.4

Summary on deployment and market-based instruments

Table 6.7 gives an overview of the deployment instruments to which the electrolyser is eligible (in effect, the SDE++) and the market-based instruments (EU ETS and carbon levy, energy taxes) which Yara is subject to, and the corresponding impacts on cash flows (potential subsidy, savings on carbon levy and additional energy-related expenditures).

Table 6.7. Impacts on cash flows from carbon levy, tax-inclusive energy costs and SDE++

Instrument	Impact on cash flows (EUR mln)	Description
ETS/Carbon Levy	105-118	Total savings up to 2030
Energy Bill and Taxes	20.8-31.6	Additional annual energy expenditures (including taxes)
SDE++	12-13.5	Annual subsidy

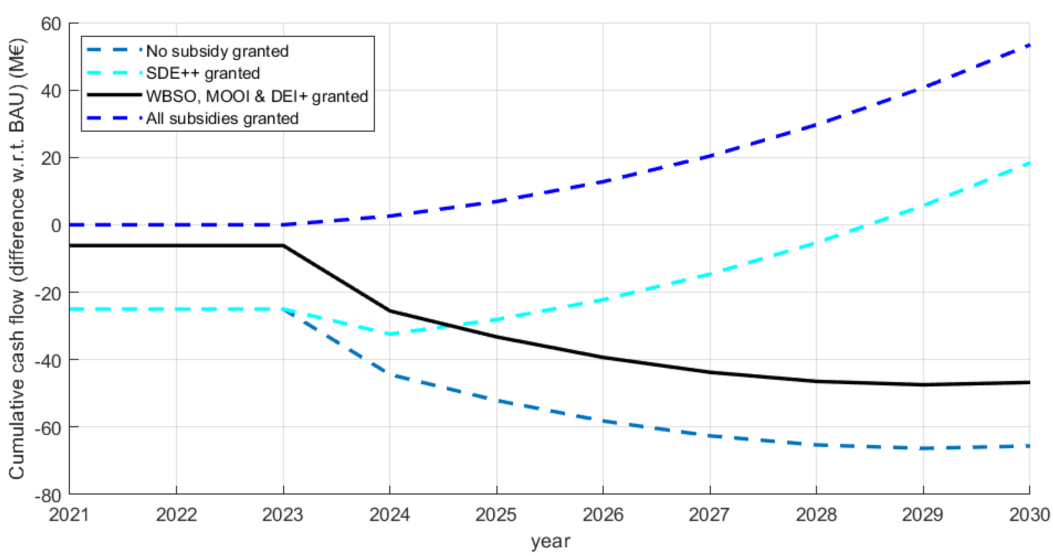
6.1.4. Cash flows, internal rate of return and project's viability

Figure 6.1 to Figure 6.3 show the combined result of the above analysis on green hydrogen's annual expected cash flows. Various scenarios are considered: high abatement (180 kt/year) vs low abatement (160 kt/year), and high versus low energy prices (as detailed in Table 6.6).

In each figure, various combinations of eligible subsidies are shown, with the solid black line corresponding to the most likely outcome. The four possible policy combinations include: no subsidy granted (bottom line), subsidies for RD&D granted (solid black line), SDE++ granted but no RD&D subsidies (dashed, light-blue) and all subsidies granted (RD&D and SDE++, top line).

Figure 6.1 presents a conservative scenario where abatement amounts to 160 kt CO_2 annually and energy prices are low. Without subsidies, the green hydrogen project is, not surprisingly, unviable despite the savings from the carbon levy. However, the main message from the figure is that current RD&D support programmes are insufficient to make the project financially attractive, even in the rather favourable case when all eligible subsidies (WBSO, MOOI and DEI+) would be granted. At the end of the period, the electrolyser becomes competitive with the BAU due to the CO_2 levy savings, but this is not enough to yield a return on the investment within this ten year period. Without support from the SDE++ (which we know is highly unlikely given the high costs associated with the project), the project never breaks even, but with the SDE++ granted (at EUR 300 per tonne of CO_2 avoided, for 2000 hours per year), it can do so before 2030.

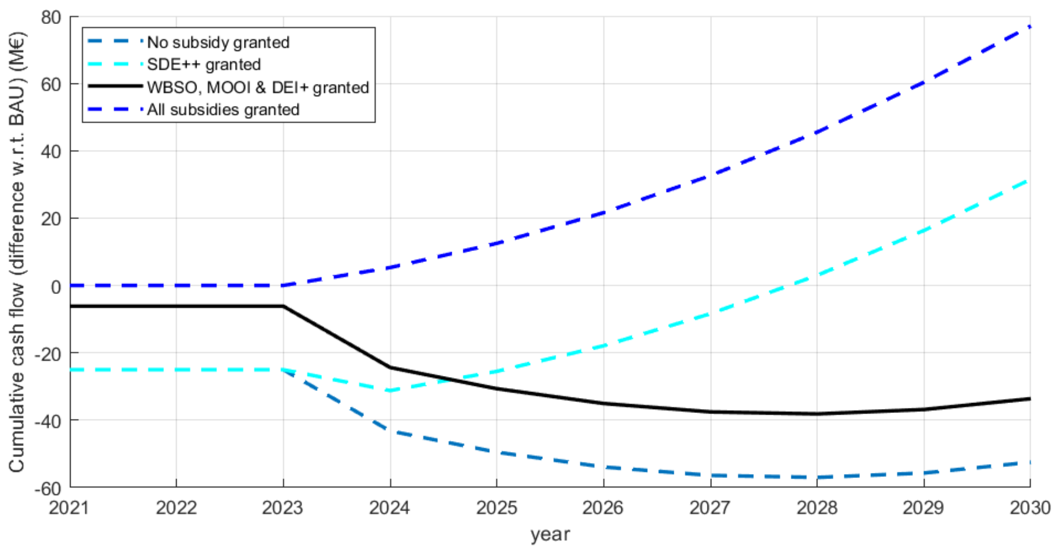
Figure 6.1. Green hydrogen electrolyser cash flows (160 kt abatement, low energy prices)



Note: the development cost is incurred in 2021 and the CAPEX in 2024.

As show in Figure 6.2, a more favourable high CO_2 abatement scenario (180kt per year instead of 160 kt) does not alter the conclusion substantially. The project becomes competitive with the BAU slightly earlier in terms of OPEX, but the additional benefits from the carbon levy savings are not high enough to make up for the initial investment costs.

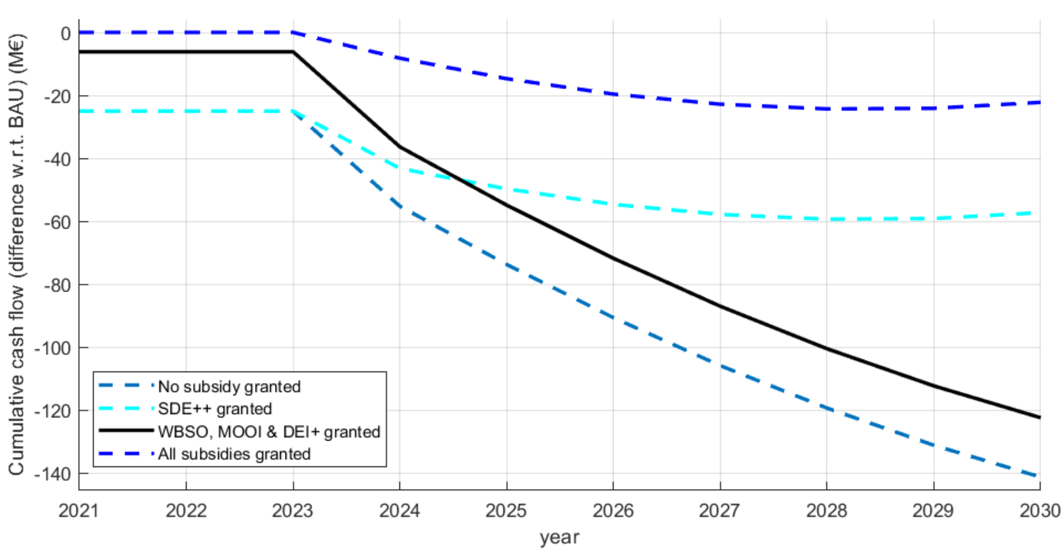
Figure 6.2. Green hydrogen electrolyser cash flows (180 kt abatement, low energy prices)



Note: The development cost is incurred in 2021 and the CAPEX in 2024.

Importantly, in the case of a high energy price scenario (with natural gas at EUR 30 /MWh and electricity price at EUR 60 /MWh), even with the SDE++ granted (at EUR 300 per tonne of CO_2 avoided, for 2 000 hours per year), the project is not financially viable until 2030 (Figure 6.3).

Figure 6.3. Green hydrogen electrolyser cash flows (160 kt abatement, high energy prices)



Note: The development cost is incurred in 2021 and the CAPEX in 2024.

6.1.5. Conclusion of Case Study 1

The analysis presented above has obvious limitations and is not designed for decision-making (this would require a more thorough modelling exercise taking into account future natural gas prices, electricity prices and feedstock contracts, etc). It has to be understood that it is illustrative of the most likely costs and benefits associated with a green hydrogen project. Nevertheless, it can be concluded that, while current policy instruments for green hydrogen should enable project developers to recoup some of the costs associated with research and development activities, they do not allow for deployment at scale. A low electricity price, abundant renewable electricity supply and an increased energy efficiency of electrolysers are drivers for the business case going forward, but at present, without the hypothetical support from the SDE++, green hydrogen projects are unlikely to be developed.

6.2. Case Study 2: Carbon capture and storage on steam methane reforming in refineries

6.2.1. Introduction

As presented in the first case study, steam methane reforming (SMR) is a CO_2-intensive process for producing hydrogen gas. In the refinery sector, hydrogen is an important feedstock used in several processes such as hydrocracking and hydrodesulphurisation. Currently, hydrogen production accounts for 21% of total CO_2 emissions in the refinery sector (2.3 Mt out of 10.7 Mt).[32] An option to produce the hydrogen more sustainably is to combine SMR with CCS. With this option, the existing SMR plants can be maintained, combined with carbon capture technology. The flue gas has a concentration of 24.2% CO_2, of which a 85% capture rate is assumed in Berenschot (2020[4]). Therefore, this option does not lead to zero emission, and in addition to this, the carbon capture technology requires electricity to run. Nevertheless, this process, referred to as "blue hydrogen" production, results in CO_2 abatement, and because of the maturity of the technology, currently at TRL 9[33], it can be implemented soon.

PBL and TNO[34] analysed different decarbonisation options for the refinery industry: 1) carbon capture; 2) fuel substitution; 3) feedstock substitution; and 4) process design. According to Berenschot (2020[4]), the vision of the petroleum industry is to apply CCS to steam methane reforming, the combination of these processes resulting in blue hydrogen. Another possibility for CCS would be to use it on centralised heat and power production, the main emission source in refineries.[35] However, the concentration of CO_2 in flue gases from these sources is insufficient to make CCS economically viable. Because electrification for CHP does not seem a viable option either, CHP could be decarbonised by replacing fossil fuel by hydrogen. Hence, the applications for hydrogen will be broader in the future, and production facilities and infrastructure, including blue hydrogen, need to be put in place.

The port of Rotterdam, where the majority of refineries in the Netherlands are located, developed a pathway towards zero emissions. This pathway consists of three consecutive steps, taking place between 2020 and 2025, between 2025 and 2030 and between 2030 and 2050. The three steps can be roughly described as: 1) energy efficiency and infrastructure; 2) change in processes; and 3) change in feedstock (Berenschot, 2020[4]). Therefore, up to 2 025 hydrogen infrastructures will be built, up to 2030 it will be reinforced to facilitate feedstock adaptations and be fully operational from 2030 onwards, at which point the Port of Rotterdam is assumed to benefit from abundant renewable electricity and to be equipped with large scale electrolysers. Either way, the demand for hydrogen gas will increase and lead to CO_2 abatement via two routes: direct abatement in hydrogen production and indirect abatement due to the switch to hydrogen as a feedstock.

Currently, there are six refineries located in the Netherlands, five of them being located in the port of Rotterdam: BP, Gunvor Petroleum Rotterdam, Vitol (Koch), EonMobil and Shell. Zeeland Refinery is located in Zeeland and is part of the Smart Delta Resources. The Port of Rotterdam is currently developing Porthos, a carbon transportation project. Of the five refineries, BP and Shell are part of the consortium of H-vision, the project aiming to have blue hydrogen available when Porthos is ready. These companies are also investigating green hydrogen options.

Among the refineries located in the Port of Rotterdam, Shell and Esso produce hydrogen via SMR. This technology accounts for about 35% of hydrogen production capacity (the two other technologies are gasification and naphtha reforming). Because Shell is part of the H-vision consortium and therefore will have access to Porthos and uses SMR, adapting a current SMR facility to a blue hydrogen facility producing 18 kt/year (comparable with the 100 MW electrolyser case study above) will be taken as the second case study.

6.2.2. Case Study Characteristics

Shells SMR facilities at the Port of Rotterdam have a nameplate capacity of 49 kt/y. These facilities cover multiple plants and therefore the integration level of these plants with capture technology is likely flexible. This enables the upgrade of part of the facility, with a capacity of 18 kt/y, towards a blue hydrogen facility. As we have seen in the first case study presented above, the associated CO_2 emissions of this activity are in the range of 160-180 kt of CO_2. Because carbon capture enables 85% abatement of these emissions, the resulting abatement is 135-150 kt CO_2 per year, while 25-30 kt of CO_2 is still released. With Shells total emissions level at its refinery being 4.25 Mt in 2016[36], this project abates about 3% of its emissions, with a potential to 8% if the entire capacity is adapted.

The carbon capture technology requires electricity. According to Berenschot (2020), the production of 115 PJ of hydrogen requires 115 PJ of natural gas and 30 PJ of electricity for blue hydrogen. Accordingly, the facility requires 0.52 TWh of natural gas and 0.14 TWh of electricity. It is unknown whether the natural gas demand rises upon installing capture technology, thus it is assumed that the natural gas consumption is unaltered and that the capture technology is entirely driven by electricity.

CCS on SMR is considered as a mature technology[37]. The flue gas typically has a concentration of 24.4% CO_2, a relatively high concentration making CCS on the system more economical than for lower concentration of flue gases. In the MIDDEN report, PBL published a breakdown of costs for CCS systems for flue gases with a concentration below 18% (Table 6.8) and a total costs estimate for blue hydrogen based on a report to be published (Table 6.9). Because the CAPEX of blue hydrogen is based on building a new SMR facility, as well as a CCS installation, in this case study the cost of a post-combustion capture system is used. With 135-150 kt of captured CO_2, the CAPEX for the capture technology is EUR 3.4-4.6 million. For the OPEX the values from (Cioli, Schure and van Dam, 2021[5]) are used, which include labour and maintenance costs, while excluding feedstock and energy costs and the cost of transport. For the installation under consideration this comes down to EUR 1.2-2.2 million per year.

Table 6.8. Costs of capture systems for different CO_2 concentrations

	Low CO2 concentration (5 %vol)	Medium CO2 concentration (8-10 %vol)	High CO2 concentration (10-18%vol)
CAPEX [EUR 2017/t CO2 captured]	45	31-39	28-31
Fixed OPEX40) [EUR 2017/ t CO2 captured/yr]	19	15-18	14-15
Steam consumption [GJ/ t CO2 captured]	2.5	2.5	2.5
Electricity consumed [kWh/ t CO2 captured]	183	149-185	162-166
CO2 avoided/CO2 captured	0.65	0.67	0.67

Source: (Oliveira and Schure, 2020[6])

Table 6.9. Costs of decarbonisation options for hydrogen production from PBL MIDDEN

Option	CAPEX	OPEX
Blue hydrogen production	90–145 EUR2017/t CO2 captured	10–15 EUR2017/t CO2 captured
Green hydrogen	3,193 EUR2017/t H2	159 EUR2017/t H2
H2 production via biomass	3,344 EUR2017/t H2	17 EUR2017/t H2
H2 production via thermal decomposition of methane	500–1,300 EUR2017/t H2	20–40 EUR2017/t H2

Source: (Oliveira and Schure, 2020[6])

In addition to the costs of the capture technology, the CO_2 needs to be transported and stored after capture. The exact business model of this value chain is not known yet, but the costs of this operation have to be covered. Although it is possible that (part of) the costs of transportation and/or storage will be subsidised directly by government funds. In this exercise we include them in the operational costs. In EBN and Gasunie (2017[7]), two firms in the Netherlands active in storage and transport in CCS projects, estimated the costs for transport and storage at EUR 9-11/t CO_2.[38] This estimate is far lower than the estimate from PBL, which stands at EUR 45/t CO_2. Because these estimates are so far apart, both are used separately in the analysis. Next to the transport and storage costs, the cost for the connection has to be paid by the emitter, which amounts to EUR 0.2-0.5 million per year. Hence, additional expenditures related to the transport and storage for this project amount to around EUR 1.4-2.2 million when assuming the Gasunie/EBN estimate, where the minimal abated emission level is multiplied by the lowest price and the maximal abated emission with the highest price. When using the PBL estimate, the transport and storage costs amount to EUR 6.3–6.8 million. CO_2 could be transported via lorries and ships, however the excellent connection with Porthos should make transportation via pipelines more economical.

An overview of the case study characteristics and costs is given in Table 6.10 below. Note that all the cost estimates are scaled by the amount of CO_2 captured.

Table 6.10. Overview of case study characteristics for a blue hydrogen project in the port of Rotterdam, where a novel CCS system is added to an existing SMR plant

Case study characteristic	Quantity
Total SMR hydrogen production Shell	49 kt/y
Blue hydrogen production capacity	18 kt/y
Emission abatement associated with CCS	135-150 kt CO2 /y
Unabated emissions	25-30 kt CO2 /y
Natural gas consumption SMR	0.52 TWh
Electricity consumption Capture Technology	0.14 TWh
CAPEX capture technology	EUR 3.8-4.6 mln
OPEX capture technology (excluding energy, transport and storage costs)	EUR 1.4-2.2 mln/y
OPEX SMR (excluding fuel costs)	EUR 3 mln/y
Transport and storage costs (including connection) using Gasunie/EBN estimate	EUR 1.4-2.2 mln
Transport and storage costs (including connection) using PBL estimate	EUR 6.3-6.8 mln/y

6.2.3. Policy instrument analysis

According to ECN and TNO, CCS technology for SMR is at TRL level 9[39]. Therefore, this technology does not require fundamental research, but rather needs to be deployed at an industrial scale. Of course, the deployment brings experience and this comes with potential cost-efficiency gains for future projects, which is an important criterion for some support schemes.

Research and Development Instruments

H2020

The H2020 grant is aimed to accelerate research. While there are calls available for CCS,[40] these are either concentrated on other sectors than the oil and gas industry, or focussed on developing parts of the technology, such as research on innovative nanocomposite membranes for capture processes. Because the case study considers the deployment of an existing technology, the project is not eligible for funds from H2020.

WBSO

The WBSO is a stimulus for R&D work, hence this project is not eligible.

MOOI (Mission-thrived Research, Development and Innovation)

This policy instrument focuses on (industrial) research and development. The scheme excludes prototype/pilot activities but includes FEED studies. Among the missions of this instrument is MMIP 6: closing industrial chains. This includes CCS[41], but due to the high TRL, this technology is covered under the DEI+ and SDE++. Also, CCS is not an innovation theme of the MOOI. Hence, this project (aside from a possible FEED study) is not eligible.

Nationaal Groeifonds (development, infrastructure and innovation)

The funds concentrate on the growth of the national economy and the creation of public value. EUR 20 billion will be injected into the Dutch economy over five years. While the infrastructure for CCS (such as CO_2 pipelines) might be part of the national growth fund, specific CCS projects are not eligible. Those are instead directed towards the SDE++ scheme in a letter dated October 2020 to parliament.[42]

Demonstration Instruments

EU Innovation fund (small scale projects, one-stage)

“Small scale projects” with capital costs between EUR 2.5 million and EUR 7.5 million are eligible for the innovation fund.[43] All sectors are included and the focus lies on CCUS, renewable energy, energy storage substitute products and cross-cutting projects. The total size of the instrument is EUR 100 million and beneficiaries can apply for a grant covering a maximum of 60% of the project costs, plus project development assistance. The project costs consider both CAPEX and OPEX,[44] the duration of which is based on the project planning, for this project it is limited to EUR 7.5 million, over 1 to 3.5 years. Although the project is eligible, special attention is given to “projects demonstrating highly innovative technologies, offering support tailored to market needs or complementing a large-scale call by targeting small-scale projects, thereby offering an opportunity in particular for small and medium-size companies”. The evaluation criteria are: 1) the degree of innovation; 2) the project maturity and greenhouse gas avoidance potential; and 3) scalability and cost efficiency, with the scores for the first two criteria having a double weight compared to the last one. While the innovative character of this project is relatively low, the project scores relatively high on maturity, scalability and cost efficiency. The grant available for this project would be EUR 2-2.8 million for the CAPEX and EUR 0.7-1.3 million for the OPEX annually, with the sum maxed at EUR 4.5 million.

Demonstration Energy and Climate Innovation

The DEI+ supports pilot and demonstration projects that contribute to cost-effective greenhouse gas abatement.[45] A project can be either a pilot or a demonstration project. Pilot or experimental development projects can apply for a direct subsidy of 25% and demonstration projects for 40% with a maximum of EUR 15 million, where the eligible amount is the additional costs of the climate-friendly investment in comparison with a similar non-climate friendly investment. For CCS, only pilot projects are eligible. CCS pilot projects consider research and validation of innovations in capture technology, which are for example required for other processes than SMR, in other sectors, where TRL levels for carbon capture technologies are lower. Because the blue hydrogen project installs existing technology and does not validate an innovative technology, the project is not eligible for funds from the DEI+.

HER+

The explicit aim of the HER+ is to reduce future subsidy expenditures (SDE++), by investing in innovative projects that bring about cost-efficiency.[46] Hence, a leading criterion is that the future savings should outweigh the requested subsidy. The HER+ includes industrial and experimental research projects for CCS and blue hydrogen[47], but excludes CCS and blue hydrogen[48] demonstrations. Because this project aims to deploy an existing technology and does not contribute to CCS research directly, the project is not eligible for funds through the HER+.

Summary on RD&D and deployment instruments

Table 6.11 gives an overview of the RD&D policy instruments for which the electrolyser is eligible to the corresponding amount of the potential subsidy. The largest, but not very likely support instrument, is the EU Innovation Fund.

Table 6.11. Eligible subsidies from RD&D instruments

Instrument	Amount Estimate
MOOI	FEED study
EU Innovation fund	EUR 2-2.8 mln for CAPEX + EUR 0.7-1.3 mln/y OPEX with a max of EUR 4.5 mln
MIA	EUR 0.3-0.4 mln via tax deduction
EIA	EUR 0.4-0.5 mln via tax deduction

Deployment instruments

VEKI

This instrument targets SMEs, hence Shell is not eligible.

MIA/Vamil

The schemes allow for an investment deduction of 36% (MIA) or 75% (Vamil). The investment must be on the *milieulijst*, which is the case for CCS apparatus, but only for the MIA scheme[49]. The maximum amount for the asset is EUR 25 million. The asset of the case study is lower than this, which makes it possible to deduct EUR 1.4-1.7 million, leading to a net benefit of EUR 0.3-0.4 million considering a tax rate of 25%.[50]

EIA

To be eligible the project must be on the *energielijst*. CCS is on this list, in particular CO_2 cleaning apparatus, CO_2 compressors, transport pipes, and CO_2-buffer reservoirs. The project is therefore eligible. With this scheme, 45% of investment costs can be deducted from the fiscal profit. This instrument will have ambiguous effects however, as Shell did not legally pay taxes in 2016-18, because selective foreign losses can be deducted from Dutch profits.[51] [52] [53] If there are profit taxes to be paid which cannot be deducted from foreign losses, the rate for this tax is 15% for EUR 0-245 000 and 25% above EUR 245 000 in 2021 (the boundary is increased to EUR 395 000 in 2022).[54] Assuming the total profit would be higher than the EUR 245 000 or EUR 395 000 boundary, the potential of the instrument is to give a tax deduction of EUR 0.4-0.5 million.

SDE++

The SDE++ is the largest Dutch policy instrument and is similar to a contract-for-difference. CCS is eligible for this subsidy within the subcategory “new capture system on existing installation”. The advised subsidy amount for this category is EUR 114.16/t CO_2 (across the four CCS categories, the average advised subsidy rate is EUR69/tCO_2). For the establishment of this amount, a rise in electricity expenditures of EUR 15/t CO_2 is taken into account and a transport cost of EUR 45/t CO_2 is taken into account, which is significantly higher than the cost estimate of Gasunie/EBN (EUR 9-11/t CO_2). With this subsidy rate, PBL estimates a break even period of nine to ten years, but this might be lower when taking into account CO_2 levy savings (although the calculations above are highly simplified) next to the savings from the ETS which PBL already takes into account.

The SDE++ grants subsidy to projects based on a cost-effectiveness criterion, for which the CCS category “new capture system on existing installation” is ranked 37th out of 95 and is the least cost-effective subcategory of CCS. This is still a fairly high position, considering for example that 12 different categories of wind on land are ranked higher (rank 1 to 36). To prevent crowding out projects in other categories, a 2.5 Mt/y cap on CO_2 emission reductions from CCS was introduced, corresponding to EUR 285.4 million annually. The requests for the SDE++ in 2020 (presented in Section 9.2) included seven CCS projects for a total subsidy requested (over the 15 years of each project) of EUR 2.135 billion and 2.35 million tonnes of CO_2 abated annually (implying a unit subsidy of EUR61/tCO_2). The total amount of annual emission reduction is lower than the 2.5 Mt cap, so in theory all projects could be granted a subsidy (especially since they have on average the lowest marginal abatement cost). This makes it very likely that the project analysed in this case study would receive the SDE++ subsidy. Depending on the exact amount of emissions abated, the total SDE++ subsidy would amount to EUR 13.7-17.1 million per year and can be granted for 15 years.

Market-based instruments

ETS/Carbon Levy

Because the new Carbon Levy is coupled with ETS, the two instruments are discussed together. The CO_2 levy is a baseline-and-credit system, where emissions above the baseline are taxed, and emissions below the baseline can be traded. The benchmark is set at the 2008 carbon efficiency and decreased by 0.2% per year to 2023 (i.e. the 2008 benchmark - 3% in 2023), the annual reduction factor starts at 1.2 and decreases by 5.7 percentage points per year until 2030. In 2021, the levy starts at EUR 30/t CO_2, increases each year by EUR 10.56/t up to EUR 125/t CO_2 in 2030. The ETS price of the previous year is subtracted from the levy. Shell is subjected to the tax and receives dispensation rights (1 DPR = 1 tonne of CO_2). Although the exact amount of DPR is unknown, it is given by the product of the activity level, the EU ETS benchmark and the reduction factor. EU ETS free allowances are granted based on the EU ETS benchmark and the plant’s output. Since we assume that the plant will generate the same output with and without CCS, the EU ETS free allowances are received in both cases and cancel out, so they do not have to be considered in this exercise.

For the SMR technology, a benchmark in the form kg CO_2/kg H_2 is not available. For an isolated SMR system, the benchmark is ambiguous because the system is highly integrated at refinery sites, and the emission level depends on, for example, the use of export steam, the level of CO_2 recirculation and the hydrogen purity. Moreover, from a chemical perspective the best available technology (BAT) for SMRs is not about CO_2 concentration reduction, but about NOx and SOx reduction. Nevertheless, the best available techniques reference document[55] states that “for every tonne of hydrogen produced, some 10 tonnes of CO_2 are produced including the amount related to steam production”. In addition, the EIGA report[56] states that “the process is chemically limited to emit at least one mole of CO_2 for every four moles of hydrogen produced”, giving a mass ratio of 5.5, while the IEA GHG reports in 2017[57] that “modern hydrogen production facilities have achieved efficiency that could reduce CO_2 emissions to about 10% above the theoretical minimum”. Finally, as mentioned already, an analysis of Praxair, one of the world’s largest hydrogen producers, concluded that the CO_2/H_2 mass ratio is 9.3, considering a plant operating at 13% above the theoretical minimum.[58] Where the mass ratio of 5.5 considers only the chemistry, the 9.3 mass ratio includes heat for the reforming energy, combustion for steam and power for separation and compression, which explains the difference.

Because the abatement level for this innovation is not based on internal reports by Shell or a technology description, but on similar assumptions about the conversion ratio, it is important for the consistency of this analysis to even the emission level with the benchmark. That is, when we consider the emissions of a 100 MW SMR to be 140-180 kt CO_2, implicitly a conversion rate of 7.8-10 CO_2/H_2 is assumed. The average of 160 kt emissions corresponds to a conversion ratio of 8.9, which is taken as the benchmark in the numerical simulation exercise, and is in the same order of magnitude as the proposed conversion ratios above. In this way, the difference between the BAU and blue hydrogen (BH) case is consistent, but forces the assumption that Shell operates a modern SMR installation. For the BH scenario, it is assumed that the system is operational in 2024, this is consistent with case study 1 and consistent with the transport and storage infrastructure opening[59].

Table 6.12 presents the annual savings from the carbon levy based on the above assumptions. The aggregate saving on CO_2 expenditures up to 2030 is EUR 88 million for the average emission level assumption. For the low emission case (140 kt), and high emission case (180 kt) and corresponding benchmarks, the aggregate savings would amount to EUR 78 and EUR 98 million, respectively.

Table 6.12. Savings from the carbon levy for the SMR CCS project

Year	Reduction factor (CE Delft)	Expected DPR (kt CO_2)	Benchmark t CO_2/ t H_2	Activity hydrogen (kt/y)	CO_2 price (EUR/t)	Expected emission BAU (t/y)	Expected penalty (EUR thsd)	Expected emissions BH (kt/y)	Expected penalty (EUR thsd)	Penalty difference (EUR thsd)
2021	1.2	192	8.9	18	30	160	-967	160	-967	0
2022	1.14	183	8.9	18	40.56	160	-918	160	-918	0
2023	1.09	175	8.9	18	51.12	160	-747	160	-747	0
2024	1.03	165	8.9	18	61.68	160	-309	25	-8 636	8 327
2025	0.97	155	8.9	18	72.24	160	333	25	-9 420	9 752
2026	0.92	147	8.9	18	82.8	160	1 045	25	-10 133	11 178
2027	0.86	138	8.9	18	93.36	160	2 075	25	-10 528	12 604
2028	0.8	128	8.9	18	103.92	160	3 309	25	-10 720	14 029
2029	0.74	119	8.9	18	114.48	160	4 745	25	-10 709	15 455
2030	0.69	111	8.9	18	125.04	160	6 185	25	-10 696	16 880

Note: The table assumes that the carbon capture technology is operational in 2024 and abates 135 out of 160 kt CO_2.

REB (Energy Tax) and ODE

The REB and ODE are the energy and electricity taxes; which Shell is subject to. According to Berenschot (2020[4]), the additional use of electricity for blue hydrogen production is 30 PJ. For the blue hydrogen installation, the additional annual consumption is therefore 0.14 TWh electricity. Again, we assume a constant electricity price, based on a study of energy and electricity price scenarios for power to ammonia from CE Delft[60] and we use EUR 40/MWh and EUR 60 /MWh, for a low and high electricity price scenario, respectively. The tariffs for the REB+ODE are 2.36 eurocent/m^3 (=0.23 eurocent/kWh) and 0.05 eurocents/kWh in 2022.[61] There is a significant reduction of 2.24 eurocent/kWh when exceeding 10 GWh annual consumption, but we assume Shell already exceeds 10 GWh annual electricity consumption without the capture technology. The additional annual operational expenditures in terms of feedstock for the blue hydrogen system is thus EUR 5.7-8.5 million. As shown in Table 6.12, the additional feedstock expenditures are generally lower than the savings from the carbon levy expenditures.

Summary on deployment and market-based instruments

Table 6.13 gives an overview of the deployment instruments to which the electrolyser is eligible (in effect, the SDE++) and the market-based instruments (EU ETS and carbon levy, energy taxes) which the project is subject to, and the corresponding impacts on cash flows (potential subsidy, savings on carbon levy and additional energy-related expenditures).

Table 6.13. Impacts on cash flows from carbon levy, tax-inclusive energy costs and SDE++

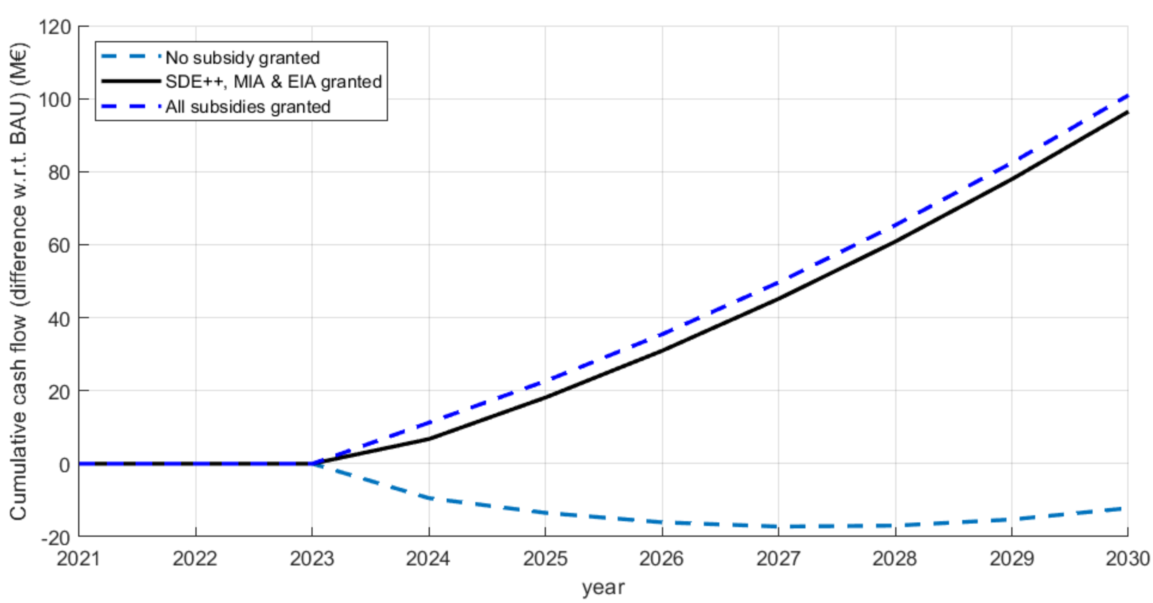
Instrument	Monetary effect (EUR mln)	Type
ETS/Carbon Levy	88-98	Total savings up to 2030
Energy Bill and Taxes	5.7-8.5	Increased energy expenditures
SDE++	14.2-17.1	Annual subsidy

6.2.4. Cash flows, internal rate of return and project's viability

Figure 6.4 to Figure 6.6 show the combined result of the above analysis on green hydrogen's annual expected cash flows. Various scenarios are considered: high vs low energy prices, and PBL vs Gasunie-EBN CO_2 transport costs (as detailed in Table 6.10).

In each figure, various combinations of eligible subsidies are shown, with the solid black line corresponding to the most likely outcome. The three possible policy combinations include: no subsidy granted (bottom line), subsidies for RD&D and SDE++ granted (solid black line), and all subsidies granted (EU Innovation Fund, MIA & EIA and SDE++, top line).

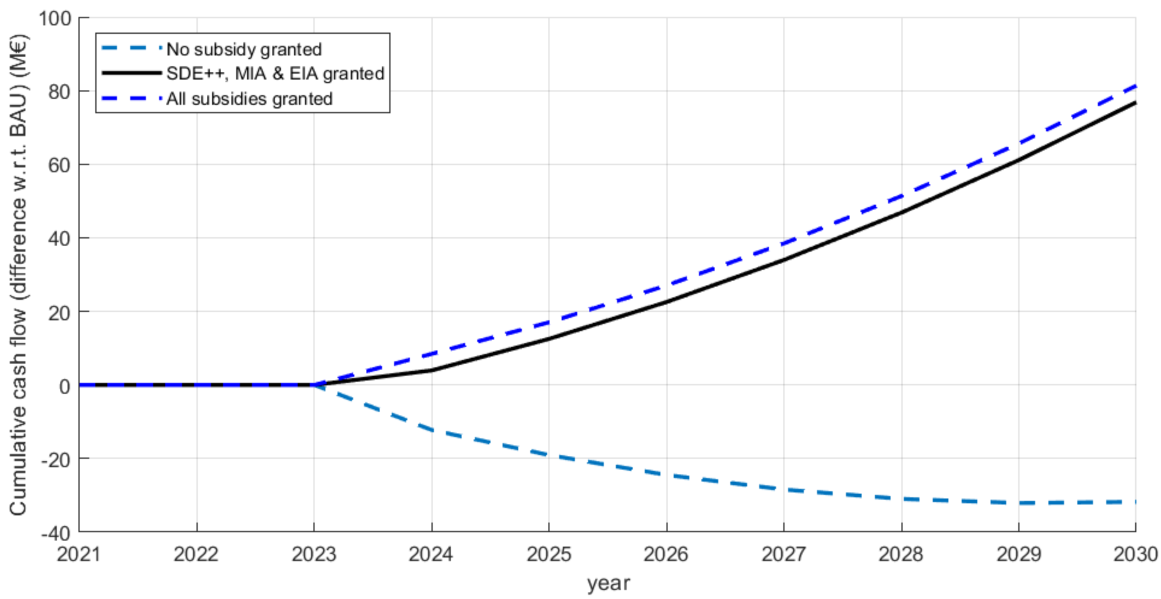
Figure 6.4. Blue hydrogen project cash flows (low energy prices, PBL CO_2 transport costs)



Note: The CAPEX is accounted for in 2024.An annual emission reduction of 135 Kt is assumed.

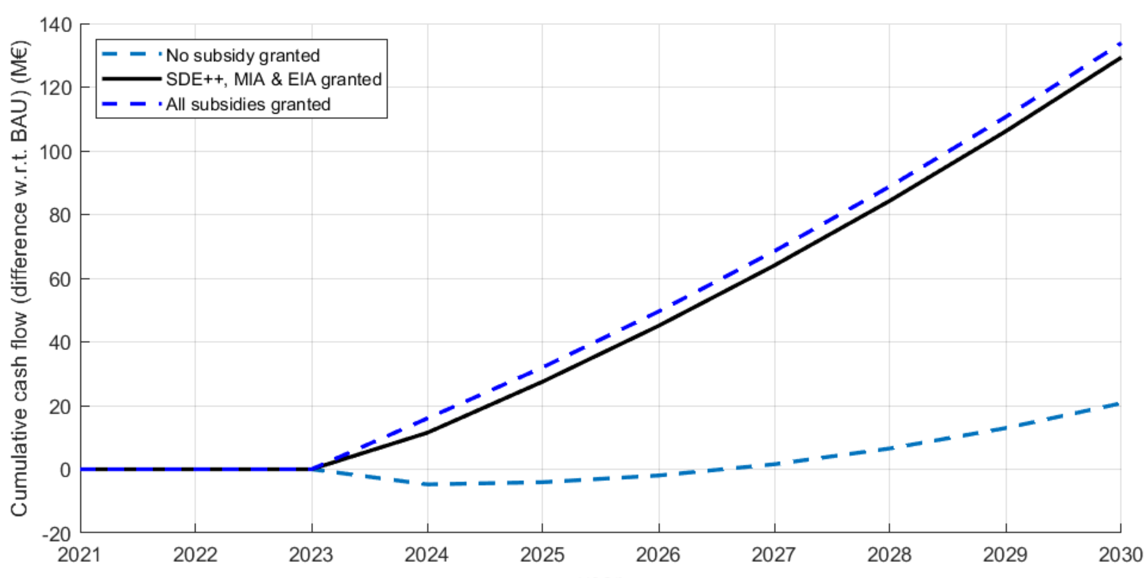
Figure 6.4 presents the conservative scenario where energy prices are low, the CO_2 transport costs are high (PBL estimate) and abatement amounts to 160 kt CO_2 annually. Without subsidies, the blue hydrogen project is unviable despite the savings from the carbon levy, but close to break even in 2030. However, the SDE++ makes the project highly attractive financially. Additional tax allowances or subsidy programmes (EU Innovation Fund, MIA & EIA) make an additional contribution, but are not critical if the SDE++ subsidy is granted, which is highly likely given the cost attractiveness of CCS projects compared to other eligible low-carbon projects. It is striking to observe that the SDE++ makes the CCS project a high return investment. This comes from the fact that savings from the carbon levy are not deducted from the SDE++ subsidy.

Figure 6.5. Blue hydrogen project cash flows (high energy prices, PBL CO_2 transport costs)



Note: The CAPEX is accounted for in 2024. An annual emission reduction of 135kt is assumed.

Figure 6.6. Blue hydrogen project cash flows (low energy prices, GasUnie-EBN CO_2 transport costs)



Note: The CAPEX is accounted for in 2024. An annual emission reduction of 135kt is assumed.

The conclusion holds if a high energy price scenario is considered (Figure 6.5). The higher relative electricity price implies additional costs, but the SDE++ subsidy is calibrated such that this does not make any difference to the overall viability of the project.

Finally, if CO_2 transport costs are lower than anticipated by PBL and closer to the Gasunie-EBN assumptions for the Porthos project, it is interesting to see that the blue hydrogen project is financially viable without support from the SDE++. The savings from the carbon levy allow the project to break even in 2027 (Figure 6.6).

6.2.5. Conclusion of Case Study 2

The analysis presented above has obvious limitations and is not designed for decision-making (this would require a more thorough modelling exercise accounting for future natural gas prices, electricity prices and feedstock contracts, etc). It has to be understood as illustrative of the most likely costs and benefits associated with a blue hydrogen project. However, the case study clearly demonstrates the attractiveness of blue hydrogen and CCS projects more generally given the current design of the SDE++. First, the relatively low costs per tonne of avoided CO_2 of CCS projects make such projects highly likely to receive subsidies from SDE++. Secondly, and more importantly, the savings from the carbon levy come in addition to the SDE++ subsidy, and make these projects doubly attractive. While savings from the EU ETS allowances are deducted ex post from the SDE++, this is not the case of carbon levy savings, which make a huge difference to the projects viability.

6.3. Conclusions from the case studies

In this chapter, two case studies are presented to put the current set of policy instruments in perspective and understand its implications for the financial viability of typical decarbonisation projects. The two case studies include green hydrogen for ammonia production in the chemicals sector (case study 1) and CCS for 'blue' hydrogen production by steam-methane reforming (SMR) in the refinery sector (case study 2). The chemicals and refineries sectors are the two largest CO_2-emitting sectors in the Dutch industry (Chapter 2). Together, hydrogen and CCS technologies would contribute to 37% of emission reductions by 2050 (Chapter 3).

Overall, the case studies confirm the major importance of the EU ETS and the two main instruments of the Dutch climate policy landscape recently introduced by the Climate Agreement: the carbon levy and the SDE++. Both instruments have large and rapid effects on the net annual cash flows associated with the two hypothetical projects. However, they have different implications.

6.3.1. Carbon levy

In the CCS case (blue hydrogen production), the avoided payments of ETS permits and carbon levy are such that they quickly compensate for the additional costs associated with the electricity consumption from the CCS device. In a rather favourable case – if energy prices remain low and transportation costs of CO_2 are lower than the current PBL estimates – the blue hydrogen project is even financially viable without additional support necessary. By contrast, in the green hydrogen case, the avoided payments of ETS permits and carbon levy are never sufficient to make the project viable and recoup the large initial investment. The carbon levy alone does not incentivise green hydrogen, but, with the current price trajectory, can quickly make the business case for CCS without other subsidies required.

6.3.2. SDE++

At present, the SDE++ appears critical for the viability of both projects, particularly in the green hydrogen case. While both projects are in theory eligible to the SDE++, the design of the SDE++, which favours projects with the lowest abatement cost, implies that the CCS project is very likely to obtain funding, provided the SDE++ ceiling on total abatement allowed through CCS is not reached, while the green hydrogen is very unlikely to receive the subsidy.

Moreover, the other key feature of the SDE++, which does not take into account savings from the carbon levy to determine the subsidy rate, implies that the CCS project gets somewhat “overcompensated” for its emission reductions. Since the CO_2 levy is not accounted for in the SDE++ scheme, the savings from the CO_2 levy are therefore a kind of “free lunch” when the SDE++ is granted. This may lead the SDE++ to incentivise the opening of new blue hydrogen production plants, resulting in higher absolute emissions (since not all emissions are captured) compared to installing capture technology on current installations or building electrolysers for green transition. It would make sense to at least partly account for carbon levy savings when determining the SDE++ subsidy rate, as savings from EU ETS allowances are already accounted for.

Strong support through climate innovation instruments (DEI+ and HER+) could help to bring about the necessary cost reductions in green hydrogen. However, further cost reductions can only be expected through scaling-up and learning-by-doing. In the absence of other available instruments to support the scaling up of green hydrogen, it could be possible to ensure that SDE++ does not only fund close-to-market technologies by allocating the tender across different TRLs in order to also support emerging technologies. At present, due to the cost-effectiveness criterion, technologies that should be scaled up to be able to allow for subsequent cost reductions are under the risk of being crowded out.

6.3.3. Electricity prices

Both the green hydrogen electrolyser and the CCS device consume large amounts of electricity. Therefore, for both projects, a low electricity price and abundant renewable electricity supply are important determinants of the business case. At present, both the pre-tax cost of electricity and the taxes on electricity consumption are higher in the Netherlands than the pre-tax cost of natural gas and the taxes on natural gas, respectively, for the same amount of energy consumed (i.e. per GJ).[62] Another implication of the case studies is thus that the current design of the electricity tax (which does not differ across energy sources used for generation) may discourage the electrification of the industry sector. With a strong carbon floor price in electricity, the elimination (or strong reduction) of the tax and ODE on electricity consumption may be envisaged. This would make the projects presented in the two case studies more viable, and make the SDE++ redundant for CCS projects, releasing funding for emerging technologies with lower TRLs, such as green hydrogen.

6.3.4. CO_2 transport costs

The CO_2 transportation and storage costs make a significant difference to the financial viability of the blue hydrogen project, which can become competitive with the current (grey) SMR process a few years after installation without the SDE++ subsidy, thanks to the carbon levy savings. Therefore, a final implication from the case studies is that infrastructure projects which help to lower the cost of CO_2 transportation and storage – such as the Porthos project – play a critical role and can contribute to reducing the future subsidies paid out of the SDE++ programme. The explicit aim of the HER+ is to reduce future subsidy expenditures through SDE++, but the programme excludes CCS and blue hydrogen demonstrations. Given the importance of CCS for short-term CO_2 emission reductions, and the large number of CCS projects submitted to the first round of SDE++ applications, making CO_2 transportation and storage projects eligible to HER+ could be envisaged. Otherwise, other programmes – potentially at European level through the Connecting Europe Facility (CEF) – could be necessary to support the deployment of a cost-effective CO_2 transportation and storage infrastructure.

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