Policy options to upscale solar PV and onshore wind beyond 2025

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Trinomics B.V.
Mauritsweg 44
NL-3012 JV Rotterdam
The Netherlands

T +31 (0) 10 3414 592
www.trinomics.eu

Authors

Joris Moerenhout
Henjo Jagtenberg
Andrea Demurtas
Mohammad Ansarin
Long Lam
Ling Ying Lee

Contacts

Joris Moerenhout
E: joris.moerenhout@trinomics.eu

Long Lam
E: long.lam@trinomics.eu

Date

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Management summary

Context, research objectives & research method

The SDE++ has been a key factor in upscaling renewable energy generation in the Netherlands. Prior arrangements and recent developments have urged the government to reconsider its design. Under the national Climate Agreement ('klimaatakkoord'), support for solar PV and onshore wind is guaranteed until 2025; a decision on (support) policies beyond 2025 must be made. Moreover, during the recent energy crisis, some renewable energy projects generated 'excess profits'. As a result, both the European Commission (in the proposed European Electricity Market Reform – EU EMR) and the Dutch Ministry of Economic Affairs and Climate Policy seek to redesign support schemes by integrating a solid mechanism to limit excess profits in times of high electricity prices. Other developments include: limited grid capacity (and increasing impact of solar PV and wind projects on system costs), a new financial context (with increased interest rates and fluctuating costs of materials), more externalities of solar PV and wind turbines as their installed capacity increases, and various governing developments (long permitting procedures, the Nevele arrest, and new regulations such as the solar ladder).

In this report, we identified four different instruments which should allow for sufficient investments in solar PV and onshore wind, and assessed their pros and cons. We also explored the extent to which these instruments can take issues as grid capacity, nature, circularity, spatial impacts and local participation into account. To do so, we first describe current developments and challenges around solar PV and onshore wind projects, we distillate key objectives that should be targeted by such instruments and identify criteria to score different options against (Chapter 2). Then, we collected information on a wide range of policy options, based on a literature review and a scan of policies abroad, which we assessed against criteria to identify four options for more detailed review (Chapter 3). Lastly, we performed this more detailed review (Chapter 4), discuss first design considerations for the best suited option (Chapter 5), and provide conclusions (Chapter 6). We used literature review, our expertise on energy policy and markets, and input from 20 interviews in our assessments.

In Chapter 2, we conclude that continued upscaling of solar PV and onshore wind and introducing a mechanism to limit excess profits is the main objective. We argue that moving away from support policies after 2025 creates a discontinuity risk for solar PV and onshore wind development, thereby putting pressure on climate targets (i.e., a zero-carbon electricity system in 2035). Therefore, we focus on support instruments that trigger continued investments. Moving towards an efficient energy system dominated by renewables and addressing key grid congestion issues are regarded as secondary objective. This is because both are directly related with the main (energy) related objective. Circularity, spatial planning, local participation, and nature are regarded as subobjectives, which *may* be targeted by a support scheme, but also outside the support scheme. Other actors, like local authorities and network operators, play a key role in pursuing secondary objectives.

Results & Conclusions

The four options selected for more detailed assessment were a 2-way contracts for difference (CfD), a Power Purchase Agreements (PPA) guarantee fund, tradeable CfDs and direct investment support. Six other options other options were explored, but not selected for a variety of reasons: a purchase obligation for energy suppliers, a 1-way CfD, direct government support with loans, carbon contracts for difference, a feed in premium and a feed in tariff.

We conclude that a 2-way CfD for solar PV and onshore wind fits best with the policy objectives and context. A 2-way CfD can be very similar to the current SDE++ (a 1-way CfD), depending on the design choices. The main difference is the mechanism to limit excess profits, where revenues are transferred to the government if the market price exceeds a set strike price. There are some main advantages of 2-way CfDs. A 2-way CfD provides revenue security for the project developer over the project exploitation period. This reduces a project developers risk exposure, which **lowers financing costs** which weigh heavily in total costs. Also, it *can* **close potential profit gaps**, which exist if the expected rate of return is not sufficiently high for a positive investment decision. This is relevant for e.g., newer technologies or applications, but also in the context of pursuing secondary objectives, which generally correspond with higher costs for project developers. Lastly, it allows to **limit excess profits**. Disadvantages are also present. The upward revenue limitation could result in higher bid prices (lower efficiency) and possibly reduce overall investment appetite (lower effectiveness) compared to the SDE++. It would also imply that the government remains involved in long term financial contracts and obligations. Lastly, 2-way CfDs hamper development of private markets. The level of many positive and negative impact depends on design choices. Nonetheless, if designed well, a 2-way CfD fits better with the policy objectives and context than the current SDE++.

A PPA guarantee fund is unlikely to align with in the required growth of solar PV and onshore project development for the climate objectives. A PPA guarantee fund limits the exposure of project developers in PPA contracts to the default risk of offtakers. PPAs are private contracts; prices are set by market dynamics, rather than by the government as in, e.g., a CfD. This implies that there is significantly less (or no) room to adjust the price to cover potential profit gaps. As a result, replacing the SDE++ by a PPA guarantee fund would likely result in a reduced project pipeline, which does not seem to align with the climate targets. It also does not align well with pursuing secondary policy objectives and does not allow a limit on excess profits. Private long-term contract markets could contribute to the transition towards an efficient energy system dominated by renewables. Incentivising those (which does not happen in the SDE++) is relevant, and a PPA guarantee fund is one way to do this. Other actions to support private market development include, e.g., further standardisation of contracts (which is also a key objective in the EU EMR).

Tradeable CfDs involve large changes, so a large discontinuity risk exists for implementation in 2026. Direct investment support does not allow a suitable limit on excess profits. A tradeable CfD (also referred to as financial or capability-based CfD) is similar to a 2-way CfD. The main difference is that the CfD contracts are tradeable. However, this scheme is still mostly academic and not applied anywhere (yet) and hence could have still unforeseen implementation issues, also since it is relatively complex. Direct investment support would simplify support but would also make it difficult to limit excess profits, since not only project costs but also uncertain revenues have to be estimated ex ante. As an additional instrument to subsidise specific elements, investment support is a promising instrument though.

All four policy options can integrate measures on energy system costs, grid congestion, nature, circularity, spatial impacts and local participation. Steering on any secondary objective fits better with support instruments which can set a price above the market price. Minimum requirements can be introduced in each instrument. However, pursuing sub- and secondary objectives generally results in higher costs. In instruments where market (price) dynamics are leading, higher costs result in lower project development. Hence, there would be a clear trade-off between pursuing climate objectives and other objectives. A 2-way CfD offers more room to steer on any objective than a PPA fund, as a 2-way CfD can financially reward market actors to pursue other objectives. The same as for PPAs applies to some extent to tradeable CfDs, which are to be sold to market actors as well.

We did not assess how to best pursue policy objectives on e.g., nature and circularity. This can be within the future instrument, but also outside the instrument, depending on the costs and benefits. To our understanding, this fundamental question has never been studied. To answer this question, one should consider multiple options and assess those on the costs and benefits. While various objectives *can* be pursued in future support instruments, it may not be desirable as it is likely to lower the effectiveness of the instrument (less renewable electricity generation) and as better options may exist. There is no one size fits all instrument.

The devil is in the detail; before implementing a 2-way CfD, numerous design choices must be made involving many trade-offs. A 2-way CfD can retain successful elements of the SDE++. However, the SDE++ is not designed to specifically reach zero carbon energy system at the lowest system costs. A future support scheme should provide incentives to reduce costs from a system perspective . We already identified certain elements in which a 2-way CfD could be improved compared to the SDE++. Most importantly, ensuring generators are exposed to short-term price signals and maximise market revenue rather than generation volumes. Both are relevant to incentivise system optimalisation and mitigate ‘price cannibalisation’. Next to this, it is possible to set criteria before receiving a subsidy, such as requiring a grid capacity indication or limiting the grid connection at 50% of max capacity (like in the SDE++ now), but more structural solutions are likely found outside of the support scheme. If more solar PV and onshore wind projects are developed without support, any measure coupled to the support scheme affects a decreasing share of the market. Lastly, we note that we only assessed 2-way CfDs in the context of solar PV and onshore wind; results are not directly applicable to other SDE++ categories as they differ in e.g. scale, maturity and market dynamics.

Summary assessment of options against criteria

Category	Criteria	1-way Contract for Difference (SDE++)	2-way CfD	PPA guarantee fund	Direct investment support	Tradeable CfD
Effectiveness: ensure continued RE expansion	Attractive profit potential	++	+	--	++	+
	Reduce project risks	++	++	+/-	-	++
Efficiency: minimise scheme cost RE per MWh	Support intensity	--	-	+	--	+/-
	Limit excess profits	-	++	++	--	+
Coherence - alignment with medium term electricity system objectives	Incentivising long-term contracts	-	+	++	+	++
	Short-term market price exposure	+/-	+/-	+	++	++
	In line with EMR	--	++	++	-	+
Coherence - steering ability	Steer on primary objectives	++	++	--	+	+/-
	Steer on other objectives	+/-	+/-	-	+	+/-
Implementation feasibility	Short term feasibility	n/a	+	+/-	+/-	--
	Long term feasibility	n/a	++	++	++	+/-
	Administrative complexity	+/-	-	+/-	+	--

++ = very positive, -- very negative, +/- could be both, depending on design. In the table we compare what could be done in the type of options. For example, the 1-way CfD option is not necessarily what is currently done in the SDE++ but what could be done within the instrument being a 1-way CfD.

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1 Introduction

1.1 Reason for this research

Although the reason for this research should be seen in a broader context, the direct reasons for this research are (1) the content of the Dutch Climate agreement and (2) recent developments in the electricity market:

1. **SDE++ support for renewable electricity (solar PV and onshore wind) projects is guaranteed until the end of 2025 or until 35 TWh was reached, according to the Climate Agreement.** In 2019, the Netherlands approved the Climate Agreement ('Klimaatakkoord'), in which the financial support for solar PV and onshore wind projects via the Support of sustainable energy production and climate transition (SDE++) mechanism was pledged until 35 TWh or the end of 2025. Since there is no explicit commitment for support after 2025 in the agreement, the Ministry of Economic Affairs and Climate Policy (EZK) has taken the opportunity to reevaluate the need and design for support for solar and wind, in light of recent developments.
2. **Due to cost reductions and changing market conditions, (subsidised) renewable energy projects have a better business case** or may even generate *excess profits* at times of high electricity prices, such as in recent years due to the Russian invasion of Ukraine and subsequent energy crisis. As a result, the European Commission's (EC) proposal for electricity market reform may force Member States to transform existing support schemes for renewable energy generation to 2-way Contracts for Difference (2-way CfD), in which profits above a certain level should be clawed back to the government. This limits the room for subsidised projects to generate high profits.

1.2 Research objectives

EZK aims to reach a balance between continued investment security after 2025 for solar PV and onshore wind, while limiting the room for excess profits. This results in the **first research question**: What options are there to offer sufficient investment security for solar PV and onshore wind, and what are their advantages and disadvantages?

In addition, the high growth rate of solar PV and onshore wind deployment in the Netherlands has resulted in new challenges. This rapid growth and resulting challenges warrant reconsidering the policy design for solar PV and onshore wind. It is relevant to understand the extent to which different policy options are suited (or can explicitly address) the new challenges induced by the rapid growth rate of solar PV and onshore wind deployment. This has led to a **second research question**: To what extent can the proposed options take potential other subobjectives into account, such as grid capacity, spatial integration, public acceptance, nature inclusiveness and circularity?

1.3 How to read this report

In this study, we identify potential support options for solar PV and onshore wind, based on a list of relevant criteria based on policy objectives. We take into account expected market developments, challenges related to onshore electricity generation, and lessons learnt from support options used in other countries.

The report in short follows the following structure:

- **Chapter 2.1 Deployment of solar PV and onshore wind.**

- **Chapter 2.2 - Objectives to be targeted in future policies** describes the policy objectives that we assume should be targeted with future support policies;
- **Chapter 2.3 – Criteria used for assessment of support options** then converts these objectives in criteria that can be used to assess the policy options.
- **Chapter 3 – Analysis and selection of most relevant policy options** starts with an overview of the full spectrum of policies which *can* (reasonably) be considered to support further solar PV and onshore wind deployment, then zooms in on certain types of support. We also scanned relevant policies abroad, such as in the UK and France. Based on this, we developed a long list of potential policy options. We do a first assessment of the long list in order to select 4 promising options for further assessment.
- **Chapter 4 – Assessment of most relevant options for further support.** Here we provide an in-depth assessment of the 4 most relevant options, along with a specific section on how sub-objectives and secondary objectives can be taken into account.
- **Chapter 5 – First considerations for a 2-way CfD design** gives first considerations for the further design of a 2-way CfD, since the 2-way CfD is assessed as one of the most promising options, hence making such an initial assessment useful guidance.
- **Chapter 6 – Conclusions –** gives the overall conclusions and recommendations based on the previous chapters.

Box 1: Glossary - List of key definitions used in this report.

Roles:

Investor:	The entity that supplies equity or a loan for a project.
Project developer:	The entity that develops a project, applies for the support, and makes the final investment decision (often also the equity provider).
Generator:	The entity that owns the plant and receives support.
Consumer:	The entity that uses energy, including small households and large industrial energy users.
Supplier:	The entity that sells energy to consumers; sometimes also called retailer.
Offtaker:	Buyer of energy (specifically for PPAs).

Financial terms:

Excess profits:	Profits higher than required by the entity for a positive business case. This is different from windfall profits, as windfall profits refer to large, unexpected profits resulting from unexpected external circumstances.
Strike price:	A fixed and pre-arranged price between parties in a CfD contract (often after receiving bids from project developers in a tender-offer or after negotiation). Also known as ‘indieningsbedrag’ and closely related to ‘basisbedrag’ in the SDE++.
Reference price:	The specific defined market-price referred to in a support scheme, to be matched with the strike price to see if the government must pay out (or will receive money back in case of a 2-way CfD). Also known as ‘correctiebedrag’ in the SDE++.
Reference period:	The period over which a reference price is calculated (e.g., a weekly average).
Settlement terms:	How and how often it is agreed between parties to pay out and/or payback.

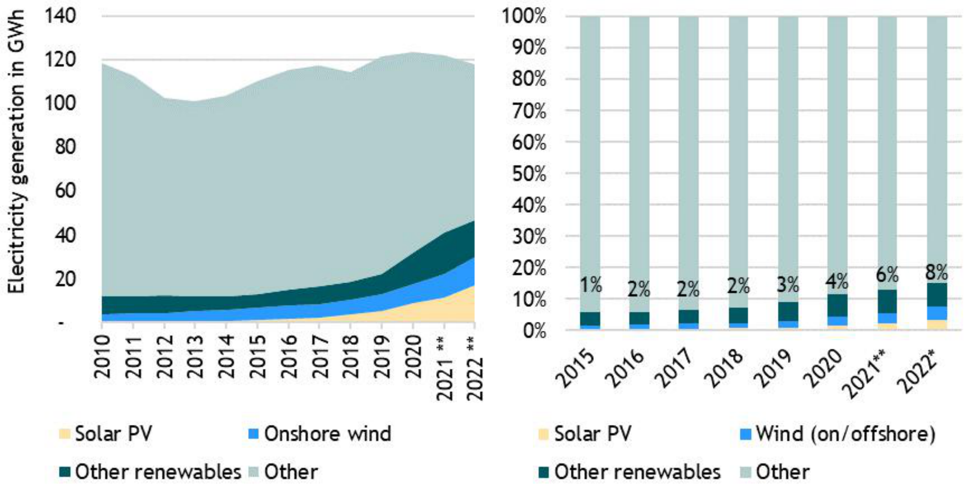
2 Solar PV and onshore wind in the Netherlands

2.1 Deployment of solar PV and onshore wind – where do we stand?

Status of solar PV and onshore wind energy in the Netherlands

Over the past decade, renewable electricity generation has grown significantly. As shown in the left panel of Figure 2-1, electricity generation by solar PV and onshore wind increased sharply, in particular since 2017. In 2022, 26% of the generated electricity was generated by onshore wind and solar PV installations. In that same year, the share of renewable electricity generation rose by 20%.[1] With these growth rates, the Netherlands has been ranked among the best scoring countries in the world, in particular with regards to solar PV. In 2022, the Netherlands generated more electricity from solar PV than from coal fired power plants.[2] The Netherlands is among the countries with the highest shares of solar PV generation globally, only leaving Chile and Jordan ahead.[3]

Figure 2-1 Electricity generation in the Netherlands by source (in GWh), left panel. Renewable energy generation as share of total energy consumption in the Netherlands, right panel.



*Right panel: the percentage in each bar shows the cumulative share of solar PV and wind. "Other renewables" does not include the statistical transfer in 2020. ** Indicate preliminary data. Source: CBS (2023).*

While the Netherlands is among the global leaders in terms of growth rates, renewable energy generation only accounted for 15% in the total *energy* consumption. Vast upscaling is still required. Decarbonising the electricity sector should continue full speed to reach climate goals. However, electricity consumption constitutes only 20% of final energy consumption (55% is heat for industry, buildings; 25% is transport fuels).[4] As a result, the share of onshore wind and solar PV in total energy consumption only equalled 8% in 2022. Most forecasts assume that many processes now fuelled by other (fossil) energy sources will be electrified to achieve full decarbonisation (such as in the draft National Energy System Plan[5]). Continued growth of renewable electricity generation is needed to accommodate this required electrification.

[1] CBS (2023). *Aandeel hernieuwbare elektriciteit met 20 procent gestegen in 2022.*
[2] Ember (2023). European Electricity Review 2023.
[3] Ember (20230. Global Electricity review 2023.
[4] CBS (2022). Totale finale energieverbruik 2022.
[5] Ministerie Economische Zaken en Klimaat (2023). *Nationaal Plan Energiesysteem.*

Current support for solar PV and onshore wind: the SDE++

Currently, both solar PV and onshore wind projects are eligible for financial support via the SDE++, which offers a minimum revenue per MWh at times when the wholesale market price is insufficient to cover project costs. The SDE++ aims to reduce greenhouse gas emissions at the lowest costs, by supporting e.g., renewable energy projects. Projects supported by the SDE++ receive a subsidy, which complements market revenues at times when the market price is below the price which is required for a bankable project. As a result, the SDE++ provides additional income to renewable energy projects and it lowers the risk profile, which lowers the financing costs.[6] Prior to the implementation of the SDE++, solar PV and onshore wind were eligible for the SDE+ subsidy, which was very similar in design, but dedicated to renewable energy only, while the SDE++ also includes other emission reduction technologies (e.g. CCS, electrification). Next to the SDE++, the Dutch government offers a variety of instruments to support investments targeting different profiles, as shown in Table 2-1.[7]

Table 2-1 Instruments to support solar PV and/or onshore wind in the Netherlands

Name	Target group	Type of instrument
Energy tax rebate	Citizens	Taxes and duties
Support of sustainable energy production and climate transition (SDE++) and predecessor (SDE and SDE+)	Businesses and non-profit organisations	Operational support
Net metering	Citizens / households	Output support
Sustainable energy investment grants (ISDE)	Businesses and citizens	Investment aid
Subsidy for cooperative energy generation (SCE)	Energy cooperations	Operational support
Energy Investment Allowance (EIA)	Businesses	Taxes and duties

Source: Government of the Netherlands (nd). Stimulating the growth of solar energy.

Almost 90% of large-scale solar PV (>15kWp)[8] and most onshore wind projects in the Netherlands are supported by the SDE++ or its predecessors; there is little incentive not to apply for the SDE++. The strong growth in renewable energy capacity is directly related to the support provided by the SDE+(+). Aside of smaller projects (e.g., residential solar PV), the vast majority of (if not all) projects apply for the SDE++. For project developers, there is no incentive not to apply for the SDE++, except its administrative burden. Between 2020 and 2022, between €1 to €4 billion was reserved for renewable electricity support per year. However, actual cash disbursements are significantly lower, as only a part of the reserved budget is disbursed, because of higher market prices. Between 2013 and 2022, the average cash disbursements from the SDE++ and its predecessors were €600 million per year for renewable electricity generation, which could increase depending on new installed capacity and electricity market prices.[7]

After 2025, there is no certainty that solar PV and onshore wind projects will be eligible for the SDE++. In the Dutch Climate agreement from 2019, support for solar PV and onshore wind from the SDE+(+) was affirmed until 35 TWh production or until the end of 2025. The 35 TWh goal was let go in 2022, when the government decided that it would continue support at least until the end of 2025, regardless of total production. Hence, EZK wants to assess the necessity and form of further support for solar and wind after 2025.

Recent challenges related to solar PV and onshore wind deployment in the Netherlands

As the energy and climate transition progresses – and as onshore electricity generation projects become more visible and form a larger share of the energy mix – new challenges arise. Until recently, the focus of renewable energy policies was on addressing one key challenge: the higher costs of renewable energy projects compared to traditional energy projects. As such, closing the financial

[6] For more information on how the SDE+(+) improves the business case for RES projects, we refer to Trinomics (2022). *Review overgangsregeling hernieuwbare elektriciteit na 2025* and/or Trinomics (2021). *Evaluatie SDE+*.
[7] For more information on the SDE, please refer to RVO (2023). *Feiten en cijfers SDE (+)(+)*.
[8] RVO (2022). *Monitor zon PV.*

gap in a cost-efficient way to further scale up solar PV and wind was the main objective of support (with technology development as a secondary goal). This has been achieved to a large extent, which has resulted in a sharp increase in solar PV and wind generation. Now, (the prioritisation of) challenges have changed compared to the early stages of renewable energy deployment. Some of these challenges are new. Other challenges have become more urgent and warrant careful consideration in this stage of the transition to a climate neutral energy system. In this section, we introduce the key current challenges in relation to renewable energy projects, after consultation with stakeholders. To do so, we separate financial, technical, governance, and public acceptance challenges.

On the financial side, renewable energy projects still face relatively high upfront costs, while future market revenues are uncertain and volatile. Recent financial challenges mentioned by stakeholders include:

- **Less optimal market conditions (e.g., increased interest rates, increased production costs) and uncertainty about future revenues.** Until 2020, virtually all major cost components related to renewable energy projects were either declining or constant. Since then, however, market developments have led certain costs to increase, due to e.g., rises in transport and material costs, installation costs, financing costs and costs related to stricter requirements.[9] Some increases were temporary and have (partially) reduced again, such as transport costs. At the same time, innovation continues, and efficiency gains are still being reached, which reduces costs. In addition, an increasingly relevant challenge for project developers in the absence of support schemes is uncertainty about future revenues. This is related to the general uncertainty about electricity prices, as well as the price that renewable electricity projects can 'capture' in the market. While a large increase in electricity demand (e.g., industry) is foreseen, the speed and timing at which electricity demand expands has a major impact on the electricity price and the business case for projects.
- **Risks of excess profits by government-supported projects during periods of high electricity prices (e.g., 2022).** With decreasing production costs and fluctuating electricity prices, the current setup of the SDE++ allows for excess revenue and possibly profits when electricity prices are above the strike price (basisbedrag). While this is positive from the project developer's side, excess profits reduce the efficiency of government support schemes since in hindsight more subsidy is awarded than needed for a reasonable business case. Recently, we have experienced very high electricity prices and hence high revenues for renewable electricity generators. These revenues were much higher than anticipated in the initial assessment of the business case, which was used to determine the support amounts. In the current SDE++, there is no mechanism to deal with excess profits.

On the energy system side, solar PV and wind developments are sometimes misaligned with the transition towards an efficient energy system dominated by intermittent renewable electricity sources. In the short term, the most urgent challenge is grid congestion, which makes realising solar PV and wind projects more difficult. This goes two ways: as the grid reinforcement costs are not borne by project developers, the rapid solar PV expansion – which only takes grid reinforcement considerations to a small extent into account – reduces optimal planning of grid reinforcements, thereby indirectly also impacting other sectors. In addition, the current SDE++ distorts some market signals which should provide the right incentives for an efficient electricity system. This results in less efficient dispatch and counteracts incentives to invest in flexibility, including storage. For instance, at times of low electricity prices, the SDE++ still compensates project owners for additional production, which makes investments in storage or demand response less attractive.

[9] IEA (2022). Special report on Solar PV global supply chains.

On the governance side, (long) permitting processes and stricter requirements (e.g., solar ladder and rules from regional governments) restrict the locations for new solar PV and wind projects. In 2020, the solar ladder ('zonneladder') announced a hierarchy of preferred locations for new solar PV. Rooftop solar PV is most preferred, followed respectively by urban areas and non-urban areas. Farmland and natural grounds are the least preferred locations. In July 2023 the EZK announced the binding character of the ladder will be reinforced and restrictions for solar PV projects on farmland and natural grounds will be further operationalised.[10,11] 72% of total ground-mounted PV installed capacity was on farmland (and 27% of total solar PV capacity, including rooftop PV) in 2021.[12] Next to this, in provincial coalition agreements the general tendency goes towards restricting solar PV on agricultural land, while reconfirming their existing commitment to reaching the RES-targets.[13]

For onshore wind, the most recent coalition agreement considers implementing a minimum distance requirement for onshore wind turbines and sensitive objects, such as homes.[14] Also, in 2021 the Council of State annulled the national environmental requirements for onshore wind parks (Nevele arrest), causing delays and uncertainty for wind parks in development.[15] This contributed to declining project pipeline for onshore wind.[16] Also, most provinces want to set further restrictions to certain types and locations of solar and wind projects, showing the current trend towards more restrictive spatial policies.[17]

Finally, there are various challenges related to the impacts on nature, spatial impacts, resource use and local participation. Based on input from EZK, from stakeholders[18], and literature, we consider impacts on nature, spatial impacts, circularity, and local participation as the most relevant set of additional challenges. While addressing these challenges is relevant, we note that this may result in additional costs.

2.2 Objectives to be targeted in future policies

2.2.1 First set objectives, then design policies

When designing a support system, the first and foremost question is: what should this policy aim to achieve? Each policy instrument should be targeting a clear policy objective. In the context of this research, this refers to the policy goals for solar PV and onshore wind beyond 2025. Many strategies and documents have been published (recently), providing policy goals and implementation directions and for solar PV and onshore wind (e.g., solar ladder, draft National Plan Energy System, Regional Energy Strategies). However, there is no explicit interpretation from the government of what all these strategies imply for solar PV and onshore wind rollout. Different objectives — e.g., the pace of renewable energy deployment, cost efficiency, inclusion of social and environmental aspects — result in different policy choices. Most importantly, translation of policy goals towards rollout of solar PV and wind requires the government to weigh the importance of different objectives, which are often not aligned and involve trade-offs. More details on this can be found in sections 2.2.2 to 2.2.4.

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[10] Ministry of Economic Affairs and Climate (2023). *2e zonnebrief over ontwikkeling zonne-energie.*
[11] For more details on further operationalisation of preference order: Bosch & Van Rijn (2023). *Onderzoek verdere verankering Voorkeursvolgorde Zon*
[12] RVO (2022). *Monitor Zon-PV 2022 in Nederland*. More info on location of solar PV can be found in Kadaster (2023). Bijna helft zonneparken in of bij bebouwde kom.
[13] NVDE (2023). Analyse provincial coalitieakkoorden.
[14] Ministry of Economic Affairs and Climate (2022). *Onderzoek afstandsnormen windturbines.*
[15] Ministry of Infrastructure and Water Management (2023). *Kamerbrief over stand van zaken Nevele arrest*.
[16] RVO (2023). *Monitor wind op land 2022.*
[17] NVDE (2023). *Analyse elf provinciale coalitieakkoorden.*
[18] Please refer to Annex II for a list of all stakeholders we have engaged with.

As the objectives are not entirely clear and are a political question, we are required to make assumptions in order to assess potential future support options. In the following section we elaborate on the objectives that we identify as important, also based on existing government policies. Our further assessment of support is based on these objectives. Where possible, we make these assumptions explicit to help decision makers find their desired balance between the goals.

2.2.2 *Main objectives for a future support mechanism*

Previous objectives of renewable energy support schemes (SDE+ and SDE++)

The direct objective of the SDE+ was to generate as much renewable energy as possible at the lowest (subsidy) costs. This changed in the SDE++ to GHG emission reduction at the lowest subsidy costs. The SDE+ operationalised its main objective by providing subsidies to projects with the lowest € subsidy per MWh renewable energy. The SDE++ instead, by providing subsidies to projects with the lowest € subsidy per avoided ton CO_2 equivalent. Both schemes are technology neutral to a large extent; project developers compete on the main objective within the same budget, regardless of differences between technologies.[19]

While the SDE+(+) delivered relatively well on their (short term) objectives, certain components are not fully aligned with the transition to a fully decarbonised energy system. The SDE+ contributed significantly to the deployment of renewable energy in the Netherlands. The technology neutral approach also contributed to the SDE+ being a cost-efficient tool to increase renewable energy production.[20] Granting subsidies to projects with the lowest production costs per MWh allows relatively cost-efficient projects to be realised with the SDE+, while projects with higher production costs are not supported. If the SDE+ is additional, this leads to cost-efficient support of the least cost renewable energy generation projects. However, the Netherlands not only aims to cut emissions by 55% in 2030, it also aims to reach climate neutrality in 2050. For the latter objective, the development of more expensive technologies or energy sources is relevant as well. This includes renewable heat and technologies that have not yet reached similar cost reductions as solar PV and wind.

In response, several changes have been implemented in the SDE+(+), such as (partially) moving away from the technology neutral approach. To ensure the deployment of a broader spectrum of technologies, guaranteed budgets ('hekjes') are introduced in the SDE++ in 2023. This implies that a share of the total budget is guaranteed for a specific group of technologies which' deployment is deemed relevant for long term goals, while not being necessarily most cost-efficient on the short run (and hence would not be granted a subsidy without the budget guarantee). In case of insufficient applications for this technology group, the remaining budget can be used in other technologies.

Policy objectives for renewable electricity generation in the near future

On the short term, the SDE+(+) plays a vital role in reaching the 2030 climate and renewable electricity goals from the Climate Agreement, and the resulting Regional Energy Strategies (RES). To reach the onshore renewable electricity generation targets from the Climate Agreement (2019), 'Regionale Energiestrategiën' were introduced. Each of the 30 RES regions, together covering the entire country, is tasked to reach a certain capacity of renewable electricity generation. As such, the RES system distributes generation capacities across the country. Each RES region can decide *how* to reach this target. The deployment of solar PV and onshore wind until 2030 is essential to meet the targets from the Climate Agreement, and the related RES targets. Many strategies assume that the SDE+(+) will be available for solar PV and onshore wind.

[19] Certain design elements already reflect steering on other factors than lowest cost, such as categories for onshore wind based on wind speed and turbine height (and thus location).
[20] See for instance: Trinomics (2021). *Evaluatie SDE+*. SDE++ is currently under evaluation. We refer to SDE+ here, as the SDE++ has not been evaluated yet.

On the long term, further deployment of renewable electricity is necessary to meet the (long term) climate and energy goals, also beyond 2030. This is confirmed by e.g., the (draft) *Nationaal Plan Energiesysteem* (NPE),[21] which foresees strong continued growth of onshore generation capacities, also beyond 2030. The NPE argues this growth is required to meet the future electricity demand, which is expected to at least double by 2035. In addition, in EZK's climate decisions from last spring, it was announced that the electricity system should be carbon free by 2035, which would hence imply continued growth of zero carbon electricity generation capacities beyond 2030.[22] We conclude that one of the policy objectives to be targeted by the proposed policy instruments is to continue the (pace of the) deployment of solar PV and onshore wind generation capacities.

If financial support is required to ensure reaching the targeted deployment rates, a key concern is specifically mitigating the risk of excess profits due to periods of high electricity prices. In the next section, we argue why we deem it is crucial to continue with smart support policies to ensure stable continued solar PV and onshore wind deployment. As the costs for solar PV and onshore wind projects are expected to continue to decline, building in mechanisms to limit potential excess profits has (and will) become increasingly relevant. This is also acknowledged by the EU, which obliged member states to implement legislation to reclaim excess profits from electricity generators in December 2022.[23] Lastly, the EC's proposal for the Electricity Market Reform states that any *operational* support mechanism for renewable energy projects should include "an upward limitation of the market revenues of the generation assets concerned", to limit excess profits.

Why is support for renewable electricity generation required to meet the objectives?

When support policies for renewable energy were first introduced, they mainly aimed to bridge the gap between the cost of renewable energy and the market price. One of the main goals of government support schemes, was to kick start the deployment of these technologies at scale, and \therefore reduce their cost to the point they could be competitive with traditional sources, such as gas. To do so, most support policies offered additional revenues to projects, above the market revenues, for instance through subsidies.

By now, very substantial cost reductions have been achieved and further costs reductions are expected. For instance, the International Energy Agency (IEA) uses a further decline for solar PV costs of 30% between 2022 and 2030 in Europe in their stated policies scenario.[24] In the past years however, CAPEX for solar PV and wind projects increased, due to supply chain disruptions, among others. As a result, transport and material costs increased. Installation costs increased as well. The expected cost reductions may not be (fully) achieved, if similar (material) cost increases occur again.[25]

Despite the achieved and expected cost reductions, renewable electricity projects still face other challenges that are likely to limit project development without government support. These challenges are related to the differences between renewable electricity projects and traditional electricity projects:

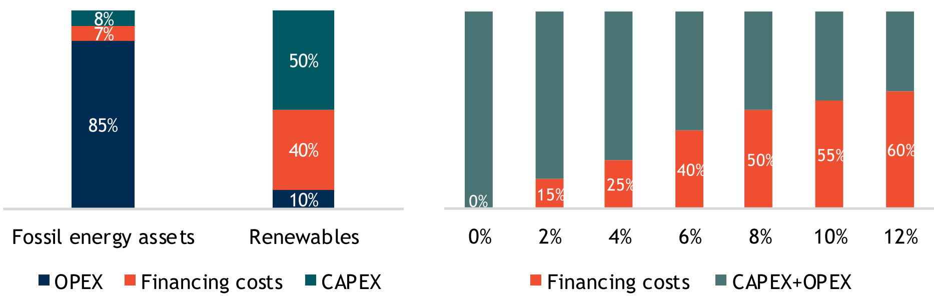
- **A large share of the lifetime costs (often >90%) of renewable electricity projects are fixed and are to be incurred upfront.** This means that solar PV and onshore wind projects have a much more rigid cost structure compared to traditional generation projects, for which fixed costs may amount to 10%-20% of the total lifetime cost of the plant.

[21] Ministry of Economic Affairs & Climate Policy (2023). *Nationaal plan energiesysteem - concept*.
[22] Ministry of Economic Affairs & Climate Policy (2023). *Voorjaarsbesluitvorming Klimaat*.
[23] Dutch central government (2022). *Heffing overwinsten elektriciteitsproducenten van kracht vanaf 1 december*.
[24] IEA (2022). World Energy Investment 2022.
[25] Trinomics (2023). *De toekomst van de HER+ voor zon-PV en wind*. Not published.

- **The market revenues of renewable electricity projects are highly uncertain**, in the absence of long-term contracts. Electricity price developments are highly uncertain, in particular on the long run. Traditional power plants also deal with this uncertainty. However, as the electricity market price is set by the marginal plant (traditionally often a gas-fired power plant), the market price of electricity varies, ensuring a period of high (coal or gas) costs is also a period of high revenues. This means that (some) fossil fuel plant investments are hedged against the risk of increases in production cost. This is not the case for renewable energy projects; a large share of costs is fixed and cannot be reduced in case of a drop in future market price. Moreover, as the share of renewable electricity generation capacity rises (and renewable energy plants are increasingly the marginal plant), the average market revenues of renewable energy plants decrease, compared to traditional generation plants. This is often referred to as revenue cannibalisation. In short, revenues are uncertain, and affected by international energy market development as well as future political decisions (on e.g., electricity market design, and electrification and renewable energy policies).

As renewable energy projects have relatively large investment costs, financing conditions have a very substantial impact on the business case, compared to traditional electricity generation projects. As most renewable projects are currently built via project finance, financing costs depend on equity and debt costs, both of which are affected by risk. For this reason, risk reduction has been long recognised as one of the main strategies to reduce the cost of renewables.[26] For example, an average cost of capital (CoC) of 6% translates into financing costs amounting to around 40% of total project costs for renewable electricity projects on average. 12% CoC even translates into financing cost amounting to 60% of total lifetime cost,[27] resulting in a 50% increase in the levelized cost of electricity.[28] This is visualised in Figure 2-2. With a high share of the costs being financial, and with high debt-to-equity ratios (i.e. a high share of the investment covered with loans, often above 75%) usually adopted for solar PV and onshore wind project, a negative feedback loop is created. As most ongoing costs are due to debt servicing, which is usually at a fixed rate throughout the contract period, renewable generators may struggle to service the debt in period of low market prices.

Figure 2-2 Distribution of CAPEX, OPEX and financing costs fossils vs. renewables (left panel) and impact of financing costs on levelized costs of energy (right panel)



Source: Kitzing (2023). Are contracts for difference here to stay?
Note: rough examples of representative solar PV / wind installation at 6% costs of capital.

In short, the cost and risk profile of solar PV and onshore wind differs from traditional electricity generation technologies, which leads to various financial challenges, e.g., for acquiring capital from institutional lenders. Support schemes such as the SDE++ significantly reduce the electricity price risk and hence the risk profile and project costs. Given the relatively high debt to equity ratio in the

[26] Steffen (2020). Estimating the cost of capital for renewable energy projects.
[27] Kitzing (2023). Are contracts for difference here to stay? *Minute 10 of the presentation*.
[28] For example, assuming a project would cost 100 (CAPEX and OPEX) and has a CoC of 6%, total cost amounts to 166, but if CoC is 12% then the total cost amounts to 250 (which is 50% higher than total costs at 6%).

capital structure of investments in renewable energy projects, debt providers are important for financing these projects. These investors have become comfortable with financing renewable energy technologies supported by the SDE++, which has caused technology specific risk premia to lower. However, in the absence of support schemes, a significant electricity price risk remains present. To hedge against these risks, lenders respond by increasing the cost of debt or by not issuing the debt at all. In short, this means that without operational support (such as the SDE++) financing costs and thus project costs would increase. For the Netherlands, Trinomics estimated that project costs could increase with 14 to 22% due to higher financing costs without SDE++.[29]

The combination of high investment costs and uncertain revenues cause challenges; continued growth of solar PV and onshore wind at the current pace in the absence of smart financial support is uncertain. For this reason, we consider financial support in a future scheme as one of the most important elements necessary to reach energy goals.

Main objective to be targeted by solar PV and onshore wind instruments after 2025
We consider **two main objectives** to be targeted by the policy instrument:

1. **Ensure a further increase in the installed capacity of solar PV and onshore wind towards 2030 (to meet targets Climate Agreement and European Renewable Energy Directive) and beyond (in line with NEP, and the spring climate decision).**
2. **Ensure risks for excess profits are properly mitigated for government-supported projects.**

2.2.3 Other relevant objectives when considering future support policies for solar PV and onshore wind

Subobjective I: moving towards an efficient energy system dominated by renewables
Moving towards an efficient, secure and zero carbon energy system is the most relevant overarching objective. This energy system will be dominated by variable renewable energy sources. Whether market-based or publicly organised, overall system-efficiency (taking into account e.g., grid and storage costs) is very relevant, as inefficiencies result in higher societal costs (and, depending on the market organisation, in higher energy prices). This system integration element is increasingly relevant, not only for solar PV and onshore wind, but also for offshore wind. While we focus on reaching the main objectives in our assessment, options will be assessed against their coherence with their subobjectives.

Medium term policies for relatively mature technologies with a near-zero marginal cost structure (such as solar PV and wind) should be directed towards the creation of well-functioning long-term contracts, closer to the maturity of the financing debt (10-15 years). This is considered one of the main solutions to address revenue uncertainty for renewables. The EC's Electricity Market Reform also aims to do this, through developing long-term markets for renewables, while keeping short-term market signals intact. It is a complex process that requires the involvement of many stakeholders, primarily national regulators, and market participants. Encouraging PPAs is a promising strategy to the lack of long-term contracts, but they are usually complex bilateral contracts and thus difficult to trade. This increases the reluctance of offtakers to enter them, and the reluctance of lenders to rely on these contracts to issue debt. However, while PPAs are becoming increasingly popular, it is unlikely that they will reach a significant portion of the market. This lack of demand for long-term supply is due to the limited ability of offtakers to enter into long-term contracts, as their own customer base has shorter contract lengths.[30] For example, a factory may have sufficient sale contracts that extend to the following 5 years, which means that they can comfortably purchase electricity with that horizon, but this will not be sufficient for a generator.

[29] Trinomics (2022). *Review overgangsregeling hernieuwbare elektriciteit na 2025.*
[30] Neuhoff, May & Richstein (2022). Financing renewables in the age of falling technology costs technology.

While solid long-term contracts can reduce long-term revenue uncertainty, both generators and consumers should be fully exposed to price signals on the short-term markets. This contributes to the efficiency of the energy system, as it provides incentives for energy efficiency and flexibility.

Subobjective II: addressing grid congestion

In the Netherlands, electricity grid congestion is one of the most pressing infrastructure related challenges, causing potential projects to be delayed or even cancelled across sectors. Grid congestion refers to the situation in which the electricity grid does not have sufficient capacity to transport electricity to the consumer. One can think of a traffic jam on the electricity grid. In case of consumption congestion, the grid's capacity is insufficient to meet the demanded electricity at the consumer's side at certain times. Projects across all sectors with electricity demand are currently delayed or even cancelled, as a result of consumption congestion. This includes electrification projects, or projects of any other kind. In case of generation congestion, grid capacity is insufficient to meet the available electricity at the generator's side. Generation congestion is relevant for intermittent electricity sources, such as solar PV and wind. During sunny/windy times, the electricity grid may not have sufficient capacity to transport the available electricity generated by solar PV and wind installations. Grid congestion is time dependent and affected by e.g., weather conditions and electricity demand.

In particular the acceleration of (ground mounted) solar PV projects in remote areas (with limited capacity distribution grids) are contributing to generation congestion in distribution networks. Solar PV (and onshore wind) project developers are affected by grid congestion as they may not get a (timely) grid connection with sufficient capacity. Distribution system operators (DSOs) are affected by the intermittent projects, as they must reinforce the electricity grid on many locations, while installation capacity is limited; in practice this means reinforcement for a PV plant comes directly at the cost of other reinforcement projects.

Despite some mechanisms to consider grid congestion in the SDE++, the full range of system integration costs are not considered in the SDE++. Implemented measures within the SDE++ include a mandatory transport indication from the DSO, which should state that there is sufficient grid capacity to receive a grid connection (at time of applying for the subsidy). As of 2023, new solar PV projects supported by the SDE++ will only get a grid connection equal to 50% of their peak capacity. Lastly, the SDE++ does not provide revenue support in negative price periods exceeding 6 hours and as of 2023 at all moments of negative prices, as per European legislation. Also, the SDE++ does not take the capacity of the entire Dutch grid into account: there is no incentive to locate a generation project close to demand[31], or to locate a project on a location with excessive grid capacity. In addition, while the SDE++ does not support projects during periods of negative prices, the SDE++ incentivises feeding electricity into the grid at periods when electricity has a price just above zero (although the newly introduced maximum 50% capacity requirement will limit cannibalisation and mitigate periods of very low or negative prices). The Netherlands also does not have producer capacity tariffs, hence not providing an incentive for producers to decrease the capacity of their grid connection.[32]

Secondary objectives - nature, spatial impacts, circularity & local participation

Onshore renewable energy projects have an impact on nature, spatial planning, and materials use. Large scale ground mounted solar PV projects, for instance, can lead to soil degradation, have an

[31] Even more so, project developer can choose to locate far away from demand (rural areas), since land is relatively cheap and with lower risks.
[32] With a producer tariff the generator pays (partially) for transporting electricity, while currently only consumers pay. Depending on the design choice, this tariff can be based on MWh (electricity generation), or MW (grid capacity).

impact on spatial planning and require substantial amounts of materials. While the negative external effects (on e.g., nature and health) of traditional electricity generation plants are magnitudes (10x) larger than the negative external effects of solar PV and wind,[33] these topics become increasingly relevant as installed capacities of onshore renewable electricity grows. Hence, these impacts should be considered when further deploying solar PV and onshore wind. While not necessary, mitigating these impacts could be considered as possible secondary objectives of renewable electricity policy. We consider:

1. **Nature:** Ground mounted solar PV projects *can* have negative impacts on soil quality and on biodiversity in general. Depending on the design choices, projects may also result in positive impacts on both. Onshore wind projects can affect nature as well, for instance by decreasing the natural habitats for birds and creating barriers for birds.
2. **Spatial planning:** Likewise, both solar PV and wind projects by definition have a spatial impact. Improved spatial planning and integration of projects in landscapes can contribute to better spatial planning and reduced impact on landscapes, thereby increasing the public acceptance.[34]
3. **Circularity:** Resource (re)use is relevant for any solar PV or wind project. Through amending e.g., design options and resource purchasing strategies, the resource use of projects can be further improved.
4. **Local participation:** solid local participation – including direct financial participation and participation during the project development process – is one of the strategies which can increase public acceptance, in particular for project affected people.

2.2.4 *Pursuing subobjectives & secondary objectives in a future support instrument (or not)*

The discussed subobjectives are all directly related with climate policies and developments; they should hence to some extent be *addressed* in a future instrument. Both progressing towards an efficient zero carbon electricity system as well as addressing net congestion is directly related to the overarching energy and climate objectives. Hence, both should be considered when designing future support schemes. Moving towards an efficient zero carbon electricity system is a condition for full decarbonisation. As climate change mitigation is the main reason for solar PV and onshore wind policies, the medium-term climate objectives are directly relevant for solar PV and onshore wind policies. Electricity grid congestion has a direct impact on the realisation of solar PV and onshore wind projects, and vice versa. Hence, considering grid congestion in a future support instrument for solar PV and onshore wind is crucial. Figure 2-3 summarises our assumptions on how different policy objectives should be considered in a support instrument for solar PV and onshore wind.

The discussed secondary objectives can be affected by solar PV and onshore wind projects and are thus relevant to *consider* in a solar PV and onshore wind policies. We note that:

- **From a coherence perspective, implementing minimum requirements on secondary objectives can be considered.** As per the Better Regulation Guidelines from the EC,[35] the coherence of policies with other policies is a relevant parameter, which should be considered when designing policies. For solar-PV and onshore wind policies, this implies that the coherence of projects with e.g., nature, spatial planning, and circular economy, should be considered. This is closely related with the *Do No Significant Harm* principle from the EC's sustainable finance guidelines, which indicates a sustainable investment should contribute to a

[33] See for instance Trinomics (2020). Energy costs, taxes and the impact of government interventions on investments - external costs, in which external costs (including e.g., health, land use, resource use, air pollution and climate) in the EU are estimated at €17/MWh for Solar PV, €168 for gas fired power plants, and €154 for coal fired power plants.
[34] For more information on the SDE+ and the relation with nature and spatial planning, see for instance: Trinomics (2021). *Evaluatie SDE+*. Chapter 4.
[35] EC (2021). Better Regulation Guidelines.

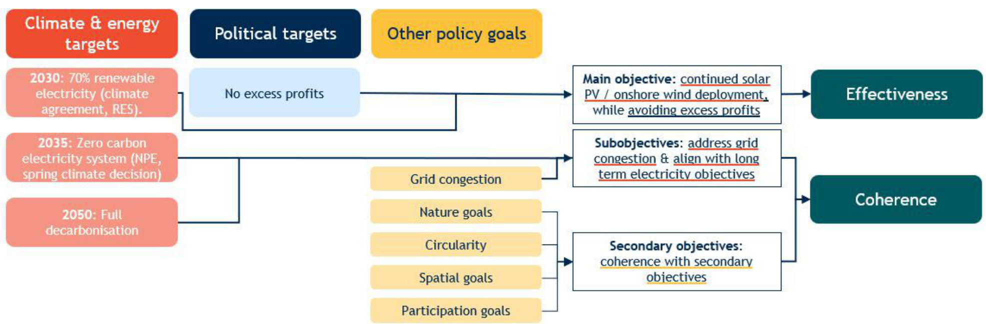
specific (environmental or social) policy objective, while preventing significant damage on other (environmental or social) objectives.

- **Pursuing specific policy objectives on non-energy topics through an energy instrument, however, may not be most effective.** It is not evident that energy policy instruments are the most efficient and effective instruments to deliver on specific policy objectives on non-energy topics, such as nature and spatial planning (without losing effectiveness on their main objective). Some policy experts argue that policy instruments should have one main objective. Hence, solar PV and onshore wind projects then should be coherent with the side objectives and when opportunities for synergies are present, they can be seized. However, pursuing specific side objectives through energy instruments is likely not most effective, when following this reasoning. There are other specific targets, dedicated policies, and responsible ministries for the secondary objectives.

Implementing (stricter) minimum requirements and pursuing secondary objectives in renewable energy projects may be covered within a future policy instrument, or outside. The key advantages of addressing challenges within a future support instrument is that it is administratively and possibly politically easier to implement. The key advantages of addressing challenges outside an instrument are that it allows for more flexibility. This is for instance the case in the current situation, where local governments decide on minimum requirements through permits. If deemed desirable, minimum requirements could also be implemented on a national level, within or outside the instrument. In addition, addressing policies outside this instrument makes solutions independent of projects participating in the instrument, or on the lifespan of the instrument. The most important argument is discussed below.

Addressing secondary policy objectives inside a future instrument for solar PV and onshore wind compromises on the effectiveness of the main objective. The most important reason to critically assess if secondary objectives should be pursued within a certain policy objective is that it usually lowers the effectiveness towards the main policy objective: in most cases there are inevitable (financial) trade-offs.[36] If the additional costs are lower than the costs for dedicated policies on these secondary objectives, this may be acceptable. If not, separated policies may be preferred.

Figure 2-3 Assumptions on relevant policy objectives to be targeted in future support scheme and transposed in main objective (assessed under effectiveness) and sub & secondary objectives (assessed under coherence).



[36] Mora Alvares & Kitzing et al. (2017). Auctions for renewable energy support - Taming the beast of competitive bidding.

2.3 Criteria used for assessment of support options

Against the background of the aforementioned challenges and relevant policy objectives, we have identified 12 criteria which we use to assess different policy options for solar PV and onshore wind. Table 2-2 shows, describes and groups these criteria. With these criteria, we take into account the effectiveness with regards to achieving the main objective, the efficiency (with support intensity, and ability to limit excess profits), coherence (with incentives for medium term electricity system targets, and the ability to steer) and the implementation feasibility.

Table 2-2 Criteria used to assess different policy options, including category and description.

Category	Criteria	Description
Effectiveness: ensure continued RE expansion	Cover profit gap	Ability to cover profit gap ('onrendabele top')
	Reduce project risks	Ability to reduce project risks/financing costs
Efficiency: minimize scheme cost per MWh of renewable energy	Support intensity	Level of expected financial government support per MWh
	Limit excess profits	Ability to limit excess profits during high electricity prices
Coherence – alignment with medium term electricity system objectives	Incentivising long-term electricity contracts	Contribution to liquid long-term electricity market
	Short term market price exposure	Exposure to short term market prices (incentivising e.g. efficient dispatch, energy efficiency and flexibility)
	In line with EMR	Alignment with EU Electricity Market Reform (EMR)
Coherence – steering ability	Steer based on policy objectives	Room to steer on how to get to climate objectives (instead of technology neutral)
	Steer specifically on secondary objectives	Room to steer specifically on secondary and subobjectives
Implementation feasibility	Short term feasibility (2025/2026)	Feasibility of implementation before 2025/2026 (year implementation period)?
	Long term feasibility	Feasibility of implementation after 2026
	Administrative complexity	Complexity of option

3 Analysis and selection of most relevant policy options

In this chapter we will work towards the selection of promising options. To do this, we will first give a broad overview of what possible support schemes are available (3.1 & 3.2). Next, we have collected and assessed relevant policies abroad that could provide useful lessons for the Netherlands (3.3). Based on these sections, we have developed a long list of potential policy options for solar and wind in the Netherlands. The options on the long list are then (partially) assessed based on the criteria selected in 2.3. 4 options were sufficiently promising and are further assessed in more detail in chapter 0.

3.1 Spectrum of options to support the deployment of solar PV & onshore wind

When encouraging renewable energy projects, four high level policy choices can be considered:

1. **Regulation** can be used to push the deployment of renewable energy, for instance based on obligations for energy generators, indicating that a certain share of their energy portfolio should be renewable, or in the form of **guarantees of origin**;
2. **Pricing**, such as imposing (higher) taxes on fossil fuel energy generation, make renewable energy relatively more cost effective than the traditional counterpart, hence encouraging renewable energy projects. A leading example is the **EU's Emissions Trading System (ETS)**. This market-based approach indirectly encourages investments in renewable energy through creating a stable market and incentivises renewable energy investments and is complementary to other support types of incentives / instruments described above. In addition, it also encourages innovation and technology development. As the EU ETS extends to the buildings, road transport, and the usage of fuels in other sectors (which are not yet defined), it will continue to steer more private investments into low-carbon and renewable energy technologies.
3. **Financial support** can come in many forms, such as **subsidies**, **loans** and **guarantees**, and;
4. **Other support**, such as **preferential treatment**, or the support that offshore wind projects get from the Dutch government (one-stop shop), can also push renewable energy deployment.

While the four options illustrate the bandwidth of options than can be considered, we focus on the key financial support schemes, as this is most relevant in the context of the discussed policy objectives. This overview is not necessarily comprehensive. The aim of this research is to identify suited policy options in the Dutch context. As such, providing a full overview is out of scope; we illustrate the broadness and then focus on identifying useful lessons for the Dutch government. Figure 3-1 illustrates the bandwidth of options that can be considered.

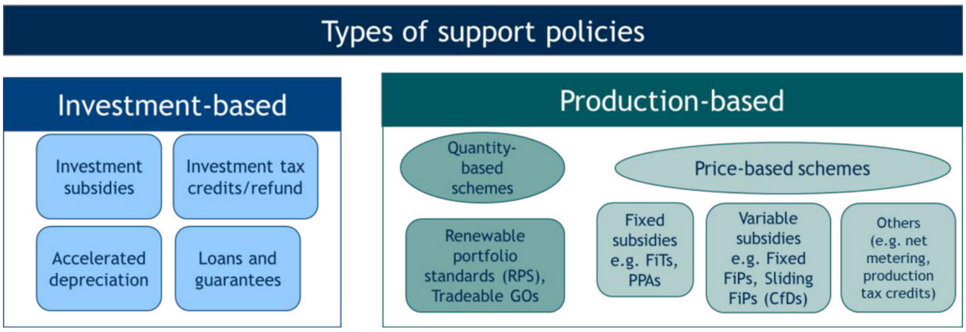
Figure 3-1 Policy toolbox for renewable energy deployment

3.2 Zooming in on support schemes

This section describes different support schemes, including their advantages and disadvantages. We note that we do not claim this overview to be comprehensive. The objective was to create a basis for our further analysis, not creating a complete overview of all options, including all advantages and disadvantages. The classification of the different types of support policies that is shown in Figure 3-2.

This section considers the guidance from the European Commission for the design of renewables support schemes.[37]

Figure 3-2 Overview of policy toolbox for solar PV and onshore wind deployment.



3.2.1 *Investment based support*

Investment grants & subsidies

Investment grants refer to direct financial contributions provided to renewable energy project developers to support the high upfront costs of such investments. Such grants may be provided as a one-time payment or disbursed during the different stages of the project development phase. Grants are usually provided for a specific purpose and are awarded through a competitive process and based on specific criteria. The recipient of the grant is usually subjected to periodic updates and evaluations on the progress. Both grants and subsidies can be awarded via competitive processes and are often used to increase research, development and innovation activities (RD&I).

Table 3-1 Pros and cons of investment grants & subsidies

Investment grants & subsidies	

Pros	• Covers and reduces financing needs for the initial investment in renewable energy (RE) projects;
	• Reduces financing costs due to:
	  ◦ Availability of a wider pool of lenders, which could increase competition; and
	  ◦ A reduction in the gearing ratio[38] of projects and hence a reduction in risk.
	• Lowers the overall cost of investment (compared to operational support), considering the returns required by private investors (lower private investment leads to lower interest payments).
	• Depending on design, it can be simple with low administrative costs, compared to other support schemes (like SDE++); limited government involvement after initial payment.
	• Investment subsidies mostly do not interfere with operational revenues and offer incentive to maximise market revenue (and hence respond to short-term price signals).
	• Mirrors the investment profile of most RE projects with its high initial investment costs.

Cons	• Exposes the government (or bill payers, if financed via the energy bill) to project risks. May be difficult to recover the grants in case of project failure and requiring guarantees would likely increase project risks and costs, nullifying the savings of project finance; • Requires a significant initial disbursement from government (or bill payers); • May create perverse incentives / strategic behaviour to underdeliver (e.g. undermaintaining asset).

Investment tax credits & tax refunds

Tax benefits, in the forms of tax credits or tax refunds, are financial incentives that reduce the tax burden of renewable energy project developers. Tax credits include having a percentage of the project's investment costs reduced from their tax liability, which can help to lower the overall costs of these investments. Tax refunds, on the other hand, are reimbursements received for a portion of their tax payments that are made, i.e., these are claimed after they file their tax returns. The slight

[37] EC (2014). European Commission guidance for the design of renewables support schemes SWD(2013) 439.
[38] Gearing ratio refers to the proportion of debt financing to equity financing. A high gearing ratio increases the risk for the project or company making the investment.

difference between tax credits and tax refunds is that tax credits are direct deductions, while tax refunds reimburse excess tax payments that have been made.

Table 3-2 Pros and cons of tax credits or tax refunds

Investment tax credits / tax refunds	

Pros	*Generally similar pros as for investment grants, but with a delayed effect, see pros and cons above:*
	• Risk reduction as exposure time to high gearing ratio is limited (financing needs for initial investment not affected);
	• A reduction in financing costs due to:
	  • Availability of a wider pool of lenders, which could increase competition; and
	  • A reduction in the time exposure of high gearing ratio of projects;
	• May be less complicated to administer than tax grants

Cons	*Generally similar cons as for investment grants above, but for a shorter period:* • Exposes the government (or bill payers, if financed via the energy bill) to project risks, although to a lesser extent than grants/subsidies.[39] May be difficult to recover the grants in case of project failure and requiring guarantees would likely increase project risks and costs, nullifying impact; • More difficult to control the budget of the scheme than in the case for grants; • May create perverse incentives / strategic behaviour to underdeliver (e.g. undermaintaining asset); • May increase administrative burden to the government compared to grants (as RE projects often use project finance); • May exclude companies with no tax liabilities from benefiting from the scheme.

Appreciated depreciation

Appreciated depreciation, which is also known as accelerated depreciation, is a mechanism which allows renewable energy project developers to recover their investment costs more quickly. Higher depreciation values reduce taxable income and tax liability.

Table 3-3 Pros and cons of appreciated depreciation

Appreciated depreciation	
Pros	• Reduces the time needed to recover investment costs; • Through the establishment of a consistent and predictable framework for depreciation benefits, governments provide stability and certainty for investors in the long term; • Government is better able to anticipate the cost (i.e., the loss of revenue) over the years; • Government does not incur a direct cost.
Cons	• Reduces the tax income received by the government over the years; • May create perverse incentives / strategic behaviour to underdeliver (e.g. undermaintaining asset); • May increase administrative burden for government (robust monitoring required to prevent abuse).

Investment loans & guarantees

Loans are typically financial assistance provided by banks or financial institutions to borrowers, to finance various aspects including the purchase of materials and operational costs. The borrowed amount is usually disbursed upfront and repaid over the loan period, along with interest and other fees. A loan with an advantageous contract (such as pay-back over a longer period or with a lower interest rate than other market options) can subsidise the development of renewable energy projects.

[39] For example, if the project fails before the entire sum may be recovered via tax credits.

Table 3-4 Pros and cons of investment loans and guarantees

Investment loans and guarantees	
Pros	• Reduces financing costs (if state-financed loans have better terms than commercial loans); • May help to finance new/emerging technologies that private investors do not support.
Cons	• Unlikely to drive significant expansion in renewable capacity; • Increases liability of the government, which may have a ripple effect, affecting the overall economic outlook of the country, and may lead to increase in investment costs in other sectors; • May not be sufficient to incentivise / support investments if market outlook remains poor; • Loans may require significant disbursement from government (or bill payers); • May create perverse incentives / strategic behaviour to underdeliver, and create an overreliance on government support.

Investment guarantees, including PPA guarantees

Guarantees involve the backing of loans from renewable energy project developers by governments. This can help for example to provide coverage against various risks such as political instability or regulatory changes. Guarantees can be private, or public (such as export credits in the Netherlands via Atradius). Guarantees can help to attract foreign or private investments for renewable energy projects.

For renewable energy projects, guarantees for Power Purchase Agreements (PPAs) reduce the financial risks of renewable energy generators against a default payment by the offtaker. Governments can also support renewable energy deployment by providing guarantees for specific PPA risks. Box 2 provides more information on PPAs. In case of (partial) guarantees against counterparty risk, this reduces the risk of energy generators losing income when the counterparty cannot pay up. Now, counterparty risk is making investors hesitant to finance solar and wind projects backed by PPAs, unless significant private guarantees are made by the counterparty.[40] There are doubts (from e.g., ACER/CEER) if counterparty risks should be covered by governments, due to its effects on other MSs and the EU electricity market. Some experts also advise to focus on developing standardised, liquid forward markets, instead of bilateral PPA contracts.

Box 2: Description of Power Purchase Agreements (PPAs)

A power purchase agreement (PPA) is a long-term commercial contract between an electricity generator and a consumer and/or supplier, whereby the generator agrees to sell a certain volume of energy directly to the customer, at a mutually agreed price. While it shares similarities to a forward contract, there are also differences (see section 1.3.2). According to the IEA[41], solar PV plants dominate renewable PPAs, with a share of almost 75% in 2020. In 2021, the top five European countries with the highest volumes of PPAs concluded are: Spain (3.9 GW), Sweden (1.9 GW), the Netherlands (1.2 GW; mostly offshore), Germany (0.75 GW) and the UK (0.62 GW).

Renewable PPAs have grown rapidly in recent years. On the generator's side, PPAs are an efficient and straightforward path to ensure revenue and hedge against high electricity price risks, thereby lowering financing costs. On the other side, consumers or suppliers aim to also hedge against price risks and ensure a level of renewable energy in their energy mix, for which PPAs are a possible tool. Consequently, a parallel market for renewable PPAs now provides a large chunk of the renewable energy trade aside from wholesale markets in many economies, including in Europe, North America, and Australia. Various risks within PPAs can be exposed to different parties, including volume and price risks, default risks, and systemic risk.

PPAs do have however several weaknesses. Given that these are bilateral contracts, significant price discovery inefficiencies and contracting costs exist. Liquidity is also generally lower than with wholesale markets.

[40] CEPR (2023). Electricity market design: Views from European economists
[41] IEA (2021). Corporate PPA volumes by technology.

Table 3-5 Pros and cons of investment guarantees, including PPA guarantees

Investment guarantees, including PPA guarantees	
Pros	• Do not involve significant disbursement from government (or bill payers); • Reduce significantly the government involvement in the energy sector; • May allow new private lenders to enter the market;
Cons	• Guarantees can reduce specific risks (default risk), but are not able to close a profit gap; hence, private PPAs – also with guarantee – are unlikely for projects that also require additional funding. • Lack of transparency and competition; high transaction/contracting costs, forming an entry barrier for smaller suppliers and consumers. • May distort market signals leading to inefficient market outcomes; • Guarantees have low liquidity as compared to general markets; • PPAs have overlap with the purpose of financial future forward, which is a standardised product and much easier to trade (higher liquidity).

3.2.2 Production based support (quantity-based)

Purchase obligations, Renewable Portfolio Standards (RPS), and Guarantees of Origin (GOs)

Purchase obligations, or Renewable Portfolio Standards (RPS), are obligations for energy users to meet a certain percentage of electricity supply from clean and/or renewable sources. Regulations on the one hand set minimum requirements for clean energy supply, while on the other hand certifying some energy sources as clean by issuing certificates of origin. The name and applicability of the certificates differs per country and/or region. In the US they are called Renewable Energy Certificates (RECs). The demand created for these certificates ensures a higher price for renewable versus non-renewable energy, thus creating an incentive for renewables. These purchase obligations for suppliers and consumers tend to increase over time, depending on the costs of renewables and the market prices for certificates. Many countries in the EU have implemented RPS obligations, including Belgium, Sweden, Latvia, Estonia, Greece, and Poland, while others around the world have similar regulations, such as the US and Australia.

In the EU, the EU-wide Guarantees of Origin (GOs) certifications are voluntary certificates that prove the origin of electricity and track ownership. Individual Member States may also certify clean electricity generation, and purchase obligations may be also implemented at the Member State level, for example as is done in Sweden and Romania. Voluntary certifications provide secondary revenue to many generators in the EU and demand is created by consumers wanting to pay a premium for 100% renewable electricity instead of obliged suppliers. Sweden began this market in 2003 and shares a market with Norway since 2012. Over the period until 2020, they plan to have 28.4 TWh of renewable electricity output mainly supported via this market. In these markets, producers are allowed to certify renewable production both for EECS and for the Nordic market. Nonetheless, the impact from the revenue from these certificates is tiny, with prices at about 22 SEK (1.9 EUR) per MWh for most of 2019-2021.[42]

GO obligations are however not as popular in Europe as other options for supporting renewables. For example, Poland replaced its purchase obligations with 2-way CfD auctions in 2016. Romania has also in recent years moved towards CfDs for supporting renewables[43], with its first auction taking place in 2023.[44] Overall, in recent years such obligation schemes are much less popular than (1- or 2-way) CfD schemes, due to multiple cons we mention in the table below.[45]

[42] Swedish Energy Agency (2021). The Electricity Certificate System.
[43] CMS (2020). RENEWABLE ENERGY LAW AND REGULATION IN ROMANIA
[44] EBRD (2023). Romania to launch first round of renewable-energy auctions under CfD scheme, with EBRD support.
[45] CEER (2021). Status Review of Renewable Support Schemes in Europe for 2018 and 2019

In the Netherlands, a guarantee of origin (GO) scheme exists for renewable energy systems and its usual revenue is integrated into the SDE++. This scheme came into existence following the EU Renewable Energy Directive II (Article 19), which requires the inclusion of guarantees of origin for renewable energy. GOs are generally traded on an EU-wide market (the EECS). In 2023, prices lie around 6-8 €/MWh, and are expected to remain at similar levels for the foreseeable future, with long term decreases on the far horizon.[46] The GO scheme has taken hold in the Netherlands, whereby by 2021, 20.39 GW of renewable generation assets were registered under the scheme.[47] The scheme provides a very minor cash flow for renewables projects, in comparison to the sale of electricity and other subsidies.

Currently, purchases of such certificates by demand (electricity suppliers and large consumers) are voluntary in the Netherlands, leading to low market prices, and thus little subsidy transfer. On the other hand, given the larger EU market for GOs, a demand push at the national level is highly unlikely to lead to higher market prices and better subsidy transfer. Setting up a national obligation (as Australia has done under the Renewable Energy Target) might not be viable or desirable. A prior study commissioned by the Dutch government in the early 2010s indicated that obligatory GOs would be overall a worse option, given circumstances at the time, compared to the existing SDE+.[48]

Combined with purchase obligations, RPSs have very low administrative burden by allowing competent buyers and sellers to manage the fiscal details of the certificates within a market-based system. The welfare impacts of non-optimal pricing and valuation are privatised (i.e., to shareholders of buyers and sellers), rather than being transferred to the public budget. Nonetheless, setting the right level of obligations can be challenging for the administrator, as this level has significant impacts both on the prices within the markets (and thus the subsidy given to renewables) and on the wider economy (by increasing the energy costs for consumers).[49] The administrative burden also does increase with the number of obliged entities.

Table 3-6 Pros and cons of purchase obligations or Renewable Portfolio Standards (RPS)

Purchase obligations, Renewable Portfolio Standards (RPS)	
Pros	• Excellent boost of renewables via a market-based mechanism (if purchase obligations are set at the right level); • Offers additional revenues for renewable energy producers in the long term; • Relatively straightforward to implement, and very low administrative burden but may require significant administrative burden to maintain when the number of obligated parties is high;
Cons	• Adds a new price risk of the certificates, thus increasing risk complexity for renewable projects; • Setting the right obligation level (and details) is a difficult task for administrator; • Only possible to steer based on volume and not value of electricity; • Leads to steering on least-cost production, while from a system perspective this is not always desirable; • Double-counting of certificates can be possible, for example by verifying renewable electricity in a local market and selling certificates also to another market; • In addition to encouraging additional investment, new GO schemes also benefit existing renewable energy production, which is usually not the intended goal of a scheme. In this case, already invested projects receive some “excess” profits;

[46] Montel (2023). EU GO prices set to hit EUR 5/MWh by 2025 – analyst.
[47] RECS (2022), Full disclosure in the Netherlands.
[48] NERA Economic Consulting (2013), Options for a Renewable Energy Supplier Obligation in the Netherlands
[49] Simshauser (2018). Garbage can theory and Australia’s National Electricity Market: Decarbonisation in a hostile policy environment.

3.2.3 Production based support (price-based)

Feed-in Tariffs (FiTs)

Feed-in Tariffs (FiTs) are fixed prices offered to renewable energy generators for each unit of electricity that is fed into the grid, i.e., quantity x tariff premium. These prices are usually independent of market prices and are usually set above the market price. The energy produced by these renewable energy generators are sometimes given priority access to the grid. FiTs can be designed in different manners. First, prices can be placed only on the gross amount of renewable electricity generated, irrespective of the energy usage of a connected “prosumer” (producer-consumer). Second, revenue can be offered only for any electricity injected into the grid, i.e., excluding the energy usage of the consumer (in other terms, the price is offered to generation minus consumption of producer-consumer). This “net metering” scheme was and still is popular for inducing self-consumption of generated electricity by households. However, with increased penetration of mainly solar PV, many of the negatives of net metering are enlarged, providing very good arguments to phase out existing net metering schemes.[50]

During the initial growth wave of renewable energy sources, FITs were highly popular, since they greatly reduced investment risk through offering a simple and guaranteed level of income. Given the very high cost of renewable energy compared to electricity market prices and the low experience with these projects at the time, such a highly de-risking scheme with adequately high pricing was necessary to promote renewables. The schemes were also simple, transparent, and rather easy to administer. Germany, various Australian territories, and US States found these tariffs to be highly popular, especially for residential users in the 2000s and 2010s. However, due to multiple concerns with equity, grid cost recovery, poor competitiveness aspects, and excess profits, these schemes are no longer considered a viable option for subsidising renewable energy projects.

While the popularity of these schemes has mostly disappeared, some modern revisions are being considered for residential and small commercial renewable energy projects. These options tackle the main issues with the scheme, namely the disconnect between market prices and FiT prices, by setting the FiT more closely based on wholesale market prices, either as a premium on market prices (Feed-in Premium schemes) or as a guarantee on top of feed-in prices (Sliding FiPs).

Table 3-7 Pros and Cons of Feed-in Tariffs (FiTs)

Fit-in Tariffs (FiTs)	
Pros	• Support different renewable technologies and of different scales, including technologies that have a good potential for reduction in costs in the future even if they are expensive now; • Simple mechanism which is ideal for small generators.
Cons	• Not straightforward to calculate the needed FIT upfront for solid business case, because this is dependent on costs and yield of the system, which may differ significantly across installations. Hence, risk of excess profits and low cost-efficiency. • May impose excessive costs to the government (or bill payers) as tariff rates are established in advance and equal for all renewable energy generators; • Generally, more suited to prosumers and small installations and new technologies rather than commercial scale installations; • Mutes market signals for investors. Transfers all market risk to the government.

Feed-in Premiums (FiPs)

Feed-in Premiums (FiPs) provide a fixed premium on top of market price for each unit of generated electricity, i.e., quantity x (market price + premium). The agreed premium is fixed and remains constant throughout the contract period. Therefore, total revenues of energy generators vary according to the fluctuations in market prices.

[50] Net metering can also be considered a separate policy instrument, outside FiTs.

Table 3-8 Pros and Cons of Fit-in Premiums (FiPs)

Fit-in Premiums (FiPs)	
Pros	• Reduces market risks (risk that market revenues are not sufficient to guarantee required returns); • May reduce financing costs for generators; some expected revenues are guaranteed by government; • If awarded via competitive auctions, it allows for regulators to discover minimum generation costs which reduces overall costs for consumers.
Cons	• Risk of excess profits if market prices stay high for long periods. • Electricity price risk does not change. Reduction in financing costs is more limited vs. SDE++. • May increase administrative burden for the government; • May disincentivise the pursuit of technology advancements. New technologies are initially more expensive; when competing with established technologies on price, they would lose the auction.

Sliding Feed-in Premium (FiPs) or Contract for Difference (CfDs)

Sliding FiPs provide a variable premium that is equal to the gap between a fixed support level and the fluctuating market price of electricity, i.e., quantity x (agreed strike price – market price). The scheme aims to provide additional support and certainty to investors on the returns over a longer period. Sliding FiPs/CfDs are currently the main instrument supporting renewable energy production in the EU. It aims to support projects with sufficient subsidy for a reasonable return. Since it supplements the market price up to a predefined strike price, it gives generators high revenue certainty and reduces the electricity price risk, which leads to lower financing costs and therefore overall project costs.[51]

A sliding feed-in premium is basically a one-way Contract for Difference (CfD), such as the SDE++. A CfD is an agreement which guarantees that the renewable energy generator will be paid a pre-agree price, i.e., the strike price, for each unit of electricity produced during the contract period. The involved parties of a CfD are typically a renewable energy generator and another party, for example, a utility company or a government entity. This provides renewable energy generators stable and predictable returns on investments of renewable energy projects.

In 2-way CfDs, projects receive compensation when the market price is below the strike price and pay back the price difference when the market price goes beyond the strike price. This helps to limit the risk of renewable energy producers from gaining excess profits during periods of high market prices; see for example the case study on the CfD scheme in the UK in Section 3.3.1. In the most recent CfD schemes payments are often based on a reference price times the produced volume, such that it should reflect project revenue, but is independent from the actual revenue received to incentivise projects to maximise revenue. In contrast, schemes such as the UK CfD are based on actual revenue and lead to 'generate-and-forget' production. In theory it is even possible to decouple payments completely from actual production, such as in the tradeable or financial CfD, as proposed by e.g., Schlecht et al.[52]

Table 3-9 Pros and Cons for sliding Feed-in Premiums (FiPs) or Contract for Differences (CfDs)

Sliding Feed-in Premiums (FiPs) or Contract for Differences (CfDs)	
Pros	• Through stable revenues, it reduces long-term market risks for the duration of the contract; • May reduce financing costs for generators; some expected revenues are guaranteed by government; • If awarded via competitive auctions, it allows for regulators to discover minimum generation costs which reduces overall costs for consumers and improves overall welfare; • Limits excess profits, especially in case of 2-way CfDs.
Cons	• Possibility for excess profits still exists during periods of high prices for 1-way CfDs (but not for 2-way CfDs); • In general, FiPs or CfDs (such as the SDE++) are administratively complex and require administrative actions for long periods (>10 years). • May disincentivise the pursuit of technology advancements

[51] Trinomics (2022). *Review overgangsregeling hernieuwbare elektriciteit na 2025.*
[52] Schlecht et al (2022). Financial wind CfDs.

Production tax credits

Production tax credits essentially operate similarly to investment tax credits (as described in Section 3.2.1) but are based on the actual volume of renewable energy generated from the plant, rather than the investment costs used for building the plant. They would be similar to a FiT, i.e. *tax reduction amount per kWh produced* x *kWh produced*. Unlike a FiT, rather than being paid directly to the generator, these subsidies are deducted from its tax bill. Compared to a one-off grant or a FiT, the generator needs to make a profit in order to benefit from the tax credit.

Table 3-10 Pros and cons for production tax credits

Production tax credits	
Pros	• Although it will not reduce the financing needs for the initial investment in RE projects, some risk is reduced as the exposure time to high gearing ratio is limited; • May reduce financing costs for generators as the exposure time to high gearing ratio is limited; • Reduce risk exposure to the government (or bill payers), as compared to investment tax credits
Cons	• More difficulty to control the budget of the scheme than in the case for grants; • Increase administrative burden to the government; • May lack transparency and accountability if not well designed and/or implemented

3.3 Scanning potentially relevant policies abroad

As part of our analysis, we have also examined designs or design elements in schemes outside of the Netherlands. This makes sure that lessons from abroad are taken into account in the selection and assessment of options. More details on the schemes in the UK (2-way CfD) and France can be found in the annex.

3.3.1 United Kingdom: Contract for Difference scheme (2-way CfD)

The UK's CfD scheme is a standard CfD instrument, with a fixed strike price for the entire duration of the contract. The contract is between the Low Carbon Contracts Company (LCCC), a private limited company owned by the Secretary of State for Business, Energy and Industrial Strategy (BEIS) to act as the contract counterparty, and a private generator. So far, the UK government has completed four allocation rounds, with the fifth one underway, and since 2023 the scheme will have one allocation round per year. The 2022 allocation round saw a record amount of capacity being awarded a contract (11 GW) at record-low prices (such as £37.35 per MWh for offshore wind). Emerging technologies such as floating offshore and tidal streams have also won a contract. As of May 2023, the UK CfD scheme has awarded 165 contracts[53] for a total 29.3 GW of capacity, with the results of the 2023 round to be released soon.[54] Operating CfD capacity[55] up to 2022 was 6.4 GW.[54] Onshore wind and solar PV projects won contracts in the first and fourth allocation rounds.

Typically, the CfD contracts last 15 years[56], are available only to new plants, and are a financial instrument rather than a purchase contract. The latter implies that the LCCC does not purchase the energy, it only pays (or receives) the difference in price between the strike price and the market price . Generators sell their energy on the market as any other generator that does not receives a CfD.

Details on the UK's CfD (key characteristics, main issues and evolution) can be found in Annex I.

Considerations and applicability to the Netherlands

The UK CfD scheme has also achieved significant results on objectives relevant for the Netherlands:

[53] 14 contracts have been terminated.
[54] UK Government (2022). Contracts for Difference and Capacity Market Scheme Update 2022.
[55] I.e., the plant financed by the contracts has started generation.
[56] With some exceptions, such as the negotiated CfD for the Hinkley nuclear power plant, which lasts for 35 years.

- **The scheme protected consumers during the recent electricity price spikes.** In 2021/2022, CfD generators paid the LCCC £419.1 million, and the LCCC paid generators £270.8 million. This means that in 2022 there were net revenues from generators amounting to £148.3 million.[57] The LCCC then paid back the excess revenues to energy suppliers (which then reduce the costs for consumers). The amount suppliers pay to the LCCC is set in advance based on expected market price, which means the values for 2021/2022 were already adjusted for the expected market price.[58]
- **Only 8% of contracts and 1% of capacity have not led to realisation so far.** This indicates that most projects are able to be realised for the strike price agreed, which means that broadly speaking the auction process produces results which are realistic.

Other elements do not align well with the Dutch policy objectives; the scheme:

- Does not consider additional elements, such as grid congestion, spatial integration, nature inclusivity and circular economy;
- Has been particularly successful for offshore wind (68% of capacity), but onshore wind and solar PV received only 5% and 8% of capacity, respectively;
- May have been partly responsible for the collapse of several suppliers in 2021 and 2022, as suppliers had to hedge consumers against wholesale risk and cannot pass the "quanto" risk[59], payments due to the LCCC.
- In the UK CfD scheme, the reference price is called the Intermittent Market Reference Price (IMRP) and is calculated using the day-ahead data received from two different market data providers (EPEX and N2EX). An IMRP is calculated for every hour of the day.[60] As this price is used to calculate payments on an hourly basis, the scheme creates a "produce and forget" incentive: generators will be paid the same amount no matter when they generate, so they have no incentive to produce when the market price is high, nor a reason to stop production when market price is below their marginal cost. This can lead to increased price cannibalisation and negative prices and is undesirable, especially now that penetration of renewables is becoming significant.

3.3.2 France: Power Purchase Agreements (PPAs) guarantee fund

The French PPA guarantee fund provides power producers the possibility to resell electricity (to consumers/grid operators), after securing administrative authorisations on their financial reliability. The French government recently issued the Renewable Energy Acceleration Bill on 10 March 2022 which had new provisions regarding the legal framework for renewable energy PPAs (Article 86 of Law No. 2023-175[61]). This law also provides local authorities with the ability to conclude long-term PPAs. Prior to this, it was almost impossible for local authorities to establish PPAs due to the limited duration of public energy contracts which lasts for two to four years.[62]

Besides attempting to create a more conducive regulatory environment, the French government has also set up a guarantee fund to increase the popularity of PPAs for renewables. This fund provides the generators with insurance against the default risk, i.e., the risk that the offtaker will not pay, thereby ensuring their revenue stream for a period between 10 and 25 years. The guarantee fund,

[57] Low carbon contracts company (2022). Annual report.
[58] Typically, at the end of a quarter, the amount collected from generators is reconciled with suppliers, with any surplus funds put toward the Total Reserve Amount (TRA), reducing the amount suppliers have to pay. If the sum of the overcollection and the current TRA is higher than the next quarter's TRA, the difference is returned to suppliers. For more information, click here.
[59] For an explanation of this risk, please see Bowden (2023). Pros and cons of Contracts for differences
[60] LCCC (2021). How Intermittent Market Reference Price (IMRP) will be calculated.
[61] Available here.
[62] PV Magazine (2023). What France's Renewable Energy Acceleration Law means for PPAs.

which is managed by BPIFrance, will be partially self-funded by the premiums paid by guaranteed contracts and partly by recovering excess profits at high market prices (this is a setup built into the guarantee, which sees the possibility for the fund to claw back revenues above the PPA price in the event that the offtaker defaults). It will enable the closing of contracts for up to 500 MW of cumulative installed power.[63]

In France there is demand for PPAs, but not sufficient supply as generators tend to prefer government-backed CfDs.[64] It is still expected that this instrument will increase in popularity the coming years, as many large electricity consumers are interested in purchasing electricity at stable prices in the long term and intermediaries are stepping forward.[65] Given the limited budget, this means that the guarantee fund will only play a marginal role in promoting the use of PPAs, and it appears set up to sign up to 10-20 contracts per year. Details on the French PPA guarantee fund (key characteristics and main issues) can be found in Annex I.

Consideration and applicability to the Netherlands

A PPA guarantee fund could be considered as a support measure, in addition to other measures to drive demand for renewable energy besides subsidising renewable energy installations. From a government perspective, the level of intervention of using regulation and state guarantees to support PPAs is minimal. This reduces administrative burdens and complexity for implementation. On the other hand, the extent to which it encourages project development may be limited. Also, many (smaller) consumers are not able or willing to enter contracts for 10-15 years, which makes PPAs only a solution for a small group of consumers.

ACER and CEER have also expressed that they are not in favour for MSs to provide state insurance for counterparty risk. This should only be done after a thorough assessment of the negative effects on other MSs and on the EU electricity market, and only with a State Aid approval. Only if benefits surpass the cost at the EU level should these instruments be implemented. They also proposed to consider other existing products such as financial futures and forwards, which are standardised long-term products that serve the same purpose; and CfDs which may be more suited for standardisation.

3.3.3 Australia: federal RPS scheme

In 2000, Australia became the first country in the world to introduce a renewable energy portfolio standard at the national level. In terms of policies, Australian state and national governments[66] have enacted Feed-in Tariffs (both as separately metered generation units and via net metering), Feed-in Premiums, Guarantees of Origin, and direct investment support among other forms of support for renewables. The certificate-based mechanism set obligations for suppliers and other large electricity customers to purchase slowly increasing levels of tradeable certificates, formed through the generation of clean energy. The end-goal, the Renewable Energy Target, sought 2% renewable energy in the country's generation mix by 2010. The target was repeatedly extended in the following years, as it became clear that the generation mix was overshooting ambitions and met its 2030 target (33 TWh generated renewably) already in 2019.[67] The scheme has boosted renewable energy generation, with about 7.1 GW installed in 2022 alone and cumulatively 31.7 GW by the end of 2022.[68] Currently, the

[63] BPI France (2023). Bpifrance to provide a guarantee for the long-term supply of green electricity.
[64] Montel (2023). France faces supply shortage in PPA market – experts.
[65] Engie (2021). PPAs for all.
[66] Australia's renewable energy subsidy policies can be divided into two groups: those that are pursued at a state level, and those set at a national level. For simplicity reasons, we focus on national policies.
[67] Simshauser (2018). Garbage can theory and Australia's National Electricity Market: Decarbonisation in a hostile policy environment.
[68] Clean energy Regulator (2023). Large-scale renewable energy target market data.

scheme is sub-categorised into the Large-scale RET (for larger assets) and the Small-scale RET (for small assets, e.g., for solar PV below 100 kWp).

The price of REC certificates has changed greatly during the market's lifetime but has mostly stayed above 30 AUD (~€18 in 2023) per certificate. More recently, prices have so far (as of August 2023) stayed above 50 AUD (~€30).[69]

Consideration and applicability to the Netherlands

While the Australian national support scheme supplemented some state-wide support schemes, it is nonetheless believed that the adequately high prices and liquid market for certificates significantly boosted renewables deployment in the country. The scheme was administratively lean, with competent buyers and sellers allowed to manage the details of price discovery and other relevant matters within the market. Generally, the concern with excess profits was less urgent than rapidly pushing renewables via market-based mechanisms. Spatial planning concerns with renewable plants were also less relevant, compared to more dense countries such as the Netherlands.

3.3.4 *United States: federal investment tax credit (ITC)*

In the US, states have been remarkably active in setting up subsidy schemes, with California being a frontrunner in providing subsidies for renewable energy installations, both small-scale and large utility-scale. Like in Australia, US's policies towards subsidising renewable energy uptake are also split between the state and federal levels.

The federal investment tax credit (ITC) is the largest subsidy scheme in the US by expenditure.[70] As before, we focus here on the federal level, namely the ITC. The ITC began originally in the 2005 Energy Policy Act, setting a 30% tax credit for investments in renewable energy.[71,72] The ITC was repeatedly extended, refined, and changed in scope to its current setting, which maintains the 30% credit until 2033 for solar (after which the credit is slowly phased out) and until 2025 for wind (after which the credit is replaced with technology-neutral credits for low-carbon generation, which are then phased out in the next years). Expenses considered for this direct investment support includes relevant hardware (e.g., solar panels, inverters, balance of system equipment, etc.), installation and other indirect costs, energy storage units (5 kWh or larger), and potentially some interconnection costs (if a project is under 5 MW). Complementing this direct support, the most recent update also includes a production-based tax credit (PTC), namely the option to instead receive a credit based on MWh produced during the first 10 years of operation. Under certain conditions, tax-exempt entities (such as non-profits or municipalities) can also benefit from the ITC/PTC as a direct payment.

Consideration and applicability to the Netherlands

The ITC and PTC policy designs also include other incentives and attributes. These include some designed to promote renewable energy in specific areas, such as areas with low income, areas with prior employment in traditional energy supply chains (e.g., coal mining, oil and gas extraction and refining, transport) and areas with prior coal-fired generation. Another policy design with a bonus tax credit promotes the use of domestically sourced materials within renewable energy installations. There are also specific labour requirements for larger (>1 MW) installations to receive the ITC/PTC. As with other forms of direct investment support, the concern of increasing renewable energy projects and creating jobs was prioritised over limiting excess profits for project developers and owners.

[69] Data available here.
[70] US Federal Energy Information Services (2023). Federal Financial Interventions and Subsidies in Energy.
[71] US office of energy efficiency and renewable energy (2023). Federal Solar Tax Credits for Businesses.
[72] US office of energy efficiency and renewable energy (2022). Production Tax Credit and Investment Tax Credit for Wind Energy.

3.3.5 Germany, Poland & Brazil: relevant components for the Netherlands

- **Poland** implemented a 2-way CfD for onshore renewables such as solar PV and wind in 2017, which was extended to offshore wind in 2023. In the Polish CfD, producers can dedicate production under CfD every year. Before every year, producers can for example dedicate a certain volume (like 70% of total production) to the CfD scheme, while relying solely on market revenues for the remaining volume.
- **Germany's** policies are not technology-neutral in various cases. In contrast to the Netherlands, various German policies steer based on technology type and/or regions using tender systems. Also, citizen-led initiatives up to a certain size do not have to participate in tenders.
- **Brazil** has a partially liberalised power market, whereby for the non-liberalised part an auction system is used to procure both renewable and non-renewable power generation capacity. While very different from the Dutch system, specifics of the auction design might be useful to consider for designing auction mechanisms for the SDE++ and its successor.[73]

3.4 Long list of policy options & selection of promising options

Table 3-11 shows the list of most relevant policy options, and Table 3-12 shows the disregarded ones, based on the available support schemes, relevant policies abroad, relevant literature, interview inputs and our expertise. All options provide some type of financial support to solar and wind projects. In section 2.2, we have argued why we believe the focus on support instruments is warranted to meet the main policy objective: continuation (of the pace) of solar PV and onshore wind deployment towards 2030 and beyond.

We have selected the four most relevant options for a further in-depth assessment in the next chapter: 1) 2-way CfDs, 2) a PPA guarantee fund, 3) direct investment support and 4) tradeable CfDs.

[73] Tolmasquim et al. (2021). Electricity market design and renewable energy auctions: The case of Brazil

Table 3-11 Most relevant policy options

	Option	Description	Main advantages	Main disadvantages
Most relevant options - further assessed in chapter 4	**2-way CfD**	Where the SDE++ is a 1-way CfD, with a 2-way CfD revenues above a certain strike price are returned to the government.	• Provides additional revenues (on top of market revenues), could reduce financing costs (similar to SDE++). • Can limit excess profits effectively. • Contributes to price stability for developers, investors, and consumers. • Improves competition and cost efficiency if awarded via competitive auctions (like SDE++) • Introduces a drawback of applying for subsidy, hence incentivising alternative contracts; possible to steer on policy objectives; encouraged in EMR.	• Requires large budget reservations. • Large risk exposure government. • For developers, less attractive than SDE++ (limited upside revenue); may lead to higher bids. • Administratively complex.
	PPA guarantee fund	A PPA guarantee fund can cover (part of) the default risk of private PPAs. This encourages the development of a private long-term contract market, as it makes PPAs more attractive.	• Promotes the development of private long-term markets and will likely increase number of private lenders on market; • More limited risk exposure for government compared to CfDs, government expenditure is lower than with a CfD. • PPAs ensure price stability for generators and offtakers. • Can be implemented next to other instruments.	• No additional revenues (on top of market revenues). Hence, questionable if PPA fund will lead to sufficient PPA demand to ensure significant rollout of renewables. • Although a guarantee fund combined with standardisation can improve this, PPAs are characterised by a lack of transparency and competition and high transaction/contracting costs, leading to an entry barrier for smaller suppliers and consumers. • Dutch market does not have ideal characteristics for quick expansion of PPA market for solar PV and onshore wind, due to high share of project financing and smaller developers.
	Investment support	Investment subsidy to cover part of CAPEX prior to or very early in project's lifetime.	• Good implementation: can be simple, quick and have low administrative costs (see e.g., US federal tax incentive); already existing scheme for smaller installations; Limited government involvement after initial payment. • Reduces financing costs through lower gearing ratio and lower private investment needs, though electricity price risks remains. • High effectiveness: directly targets a main barrier to growth in renewables: high initial investment costs. • Good coherence: Could be combined with other support and policies for other objectives; Projects fully exposed to market price signals.	• Poor efficiency: difficult to estimate the necessary investment subsidy for project realisation. Relatively large risk that amount is too low (=no project realisation) or too high (=excess profits), hence raising doubts on cost effectiveness. There also is no easy way to claw back potential excess profits. • Exposes government (or bill payers) to project risks and may be difficult to recover grant in case of project failure. • Does not reduce the electricity price risk to same extent as a CfD.
	Financial (capability-based) CfD	2-way CfD converted into standardized product that can be sold to private consumers.	• Developers are encouraged to maximise market revenue, without distortions from subsidies. • Financial product can be sold to consumers, hence developing private long-term market.	• New (unproven); implementation issues may arise, such as calculating the reference price and defining the role of government and seller. • Experts divided if pros outweighs the cons, warranting a large change from 'traditional' CfDs.

Table 3-12 Disregarded policy options

	Option	Description	Main advantages	Main disadvantages
Considered, but disregarded options	**Purchase obligation for energy suppliers**	Oblige energy suppliers to buy renewable energy certificates. Implemented in many countries, some countries gradually transitioning to other support mechanisms, due to drawbacks.	• Secure option to ensure sufficient deployment, since it is an obligation.	• Does not address electricity price risk; adds additional price risk through unstable GO price. • Not possible to steer on other objectives than renewable energy volume. • Very big change (vs. SDE++) • Incentivises generators to maximise production (not market revenue); distorting price signals.
	1-way CfD with ex-ante correction for excess revenue risk ('Overgangs-regeling')	Similar to the SDE++, but with ex-ante correction of strike price to compensate for forecasted revenues above strike price.[74]	• Reduces excess profit risk. • No payments to government (in contrast to 2-way CfD).	• Significant uncertainty is inevitable in forecasting the revenue risk, making it more difficult to calculate the required strike price, hence reduces the effectiveness of support.
	Direct government support via loans (preferential rate)	Governmental loans with better conditions (e.g., lower interest rates vs. market)	• Reduces the challenges of finding sufficient private financing. • Reduces financing costs, and therefore lowers required returns	• No development of private financing market. • No additional revenues (on top of market revenues). • Large involvement government, high risk exposure. •
	Carbon Contracts for Difference	CfD based on GHG emission reduction.	• Steers on emission reduction.	• Adds unnecessary additional complexity. • Less effective for solar PV and wind deployment. • Does not always allow to steer on sub targets (i.e., technology development).
	Feed-in premium	Fixed premium per MWh on top of market price.	• Additional revenues (on top of market revenues). • If awarded via competitive auctions, relatively solid way to ensure deployment solar PV and wind.	• Risk for high excess profits and low efficiency; FIP payments are independent of other (insecure) revenues during the total 15-20 year payment period. • Incoherent with EC recommendations in EMR • Electricity price risk stays the same; reduction financing costs more limited vs. SDE++.
	Feed-in tariff	Pay a fixed price per MWh delivered to the grid.	• Effective: Simple and predictable revenue for developers. Additional revenues (on top of market revenues).	• Poor efficiency: generators do not face market price signals and difficulty in setting correct price. High risk of excess profits • Incoherent with EC recommendations in EMR

[74] See for detailed assessment and explanation Trinomics (2022). *Review overgangsregeling hernieuwbare elektriciteit na 2025.*

4 Assessment of most relevant options for further solar PV & onshore wind deployment

In this section, we present our analysis of the four options selected based on our preliminary analysis and based on EZK and stakeholders' feedback. Based on this assessment, and on the further arguments developed below, a 2-way CfD appears the most suitable option for supporting solar PV and wind in the Netherlands in the short term (2025 to 2030). For this reason, chapter 5 provides further implementation details on this option.

4.1 Option 1: A 2-way CfD

Description

A 2-way CfD is in principle very similar to the current design of the SDE++ (which can be considered a 1-way CfD). Where now generators can keep all their revenues when the market price is higher than the strike price (basisbedrag), with a 2-way CfD revenues above the strike price are returned to the government (or the contractual counterpart of the CfD). There are several ways in which a CfD scheme can be designed to limit the issues seen in current implementations (see paragraphs below) and fit the Dutch environment. For example, while the majority of current implementations across other Member States have a single strike price, in theory the scheme could be designed with a 'range', where generators keep some of the price risks at low market prices but could potentially earn more revenues in case market prices are higher. In chapter 0, we will discuss the main design choices and implementation details, while in this section we look at the core design of a 2-way CfD and its pros and cons.

Analysis

A CfD scheme scores positively across the list of criteria selected to perform this analysis.
A 2-way CfD support mechanism will be perfectly aligned with the proposed EMR, will reduce electricity price risk and hence financing costs for developers, while ensuring any profit gap potentially created by future low prices is covered. On the other hand, a CfD scheme still has some downsides for the government. For example, it can lock the government into supporting onshore wind and solar PV installations for several years, and possibly at high prices. The scores on some criteria depend on the actual design of the CfD. In those cases, the score is based on what is possible in implementation (described in the next chapter).

A 2-way CfD is a solid option to ensure further solar and onshore wind development while limiting the risk of excess profits. A government CfD support scheme fills the market gap for long-term contracts while hedging the consumers (taxpayers) against future rises in energy market prices, such as those seen in recent years. The main advantage of a 2-way CfD scheme compared to the current SDE++ mechanism is the upwards revenue limitation, which eliminates the risk of excess profits for contracted generators for the duration of the contract. The EC in its draft EU EMR proposes to oblige Member States to provide operational support to solar PV and onshore wind only via 2-way CfDs. This is proposed partially in response to potential excess profits made by renewable generators during the recent energy crisis.

The 2-way CfD adds a clear drawback for project developers: project developers lose the potential upside. This can (slowly) encourage private long-term contract market development. This is a difference compared to the SDE++, which does not provide any reason to not apply for the subsidy. Depending on CfD design and market conditions, higher revenues may be achieved on the private market. Hence, the drawback for project developers in applying for the CfD could slowly encourage private long-term market development. The extent to which developers choose to opt for private contracts (instead of the CfD) also discloses relevant information on the alignment between the CfDs strike price and market expectations from project developers.[75] The reduced possibility to earn profits above those guaranteed by the strike price may discourage some investors and therefore slow down the pipeline of new projects, forming a risk for the renewable deployment targets. In addition, a 2-way CfD may yield bid prices which are higher than they would be in the SDE++. When investors bid for a 1-way CfD, they may include the expectations that market prices will be above the strike price for a significant amount of time. Being able to retain these revenues (while limiting the risk of low prices thanks to the strike price) means that they may bid for a lower strike price than without this upside revenue opportunity.

CfDs still have a number of distortionary effects on the market. In their response to the consultation to the proposed EMR,[76] ACER and CEER provided a comprehensive list of issues with CfDs, of which some also apply to the current SDE++. The box below lists their key points.

Box 3: Reaction to the European Commission's public consultation on electricity market design

1. They may have a negative impact on short term markets (e.g., providing inefficient dispatch incentives such as to stop producing when prices are below their marginal costs). This could also impact investment efficiency (maximising generation output rather than market value).
2. They may significantly reduce the liquidity of forward markets and reduce the scope for competition in retail markets.
3. They may reduce the revenue uncertainty more than necessary. It may be rational or sufficient to reduce only extreme uncertainty faced by investors, whereas 'normal' uncertainty (faced by investors in all economic sectors) should remain for investors.
4. They may lock-in the average price for consumers for very long periods (e.g., 20 years) for the volume of contracted CfDs, without taking into account consumer's preferences. It may instead be enough to only protect them against sustained periods of high prices.
5. They could lead to higher average prices for consumers, as the competition at CfD auctions may not achieve the level of competition experienced within integrated short-term markets (e.g., due to lack of internal competitors, no cross-border competition and high risk premia).
6. Central procurement of CfDs by the state may end up in the inefficient outcome of over dimensioning and overinvestment of electricity system historically observed in regulated electricity systems.
7. As the design of state contracts may depend on specific technology, such centrally procured contracts risk making arbitrary (and possibly suboptimal) decisions on which technologies are subsidised to which extent. This may hamper incentives for innovation of other new and more efficient technologies.

New CfD designs are minimising the downsides of CfDs. For example, there are options to design a CfD scheme that incentivises efficient dispatch choices and reduces some of these issues. A CfD scheme should encourage generators to maximise market revenues, rather than production. To do this, the reference price payments should be as much as possible decoupled from actual production. In this way, actual production decisions are guided by market revenue maximisation, instead of subsidy maximisation strategies. When generation decisions are both steered by market revenues and subsidy maximisation, this may affect, for example, the siting/direction choices of some installations: when maximising revenue, east- or west-facing solar PV with lower production but higher value are encouraged; or wind farms in suboptimal locations, but that would generate when main winds are down. It would also ensure maintenance is planned optimally. Through a smart reference price design, may eliminate the "generate-and-forget" mentality and incentivises generators to dispatch cost-effectively. These design options will be discussed in more detail in chapter 5.

[75] While it is likely that not supported projects will use Over-The-Counter contracts where the contract price is not disclosed, the amount of non-support contract volume is available and already can give information about the type and volume of projects that don't apply for support, which is useful to monitor.
[76] Acer-CEER (2023). Reaction to the European Commission's public consultation on electricity market design.

While not very common, the auction rules (such as minimum requirements and the ranking methodology) can be designed to promote other objectives. As in the SDE++, participants may be required to present building permits and connection agreements; additional points for the ranking can be awarded for locations and technologies that minimise network congestion, promote the use of more circular products and have a better public acceptance. Some countries have tried this approach in the past (for example, France), or are currently considering this aspect. The UK government has recently launched a consultation for introducing non-price factors into the CfD scheme, including *sustainability*, *capacity building*, *innovation addressing skills gaps*, and *enabling system flexibility and operability*.[77]

Overall assessment

2-way CfDs have grown in popularity across MSs and are now recommended by the EC, ACER and other key institutions. The EC is even considering, in the proposed EMR, to what extent these should be mandatory, rather than only recommended, for supporting inframarginal generators. In general, 2-way CfDs are assessed as a promising option for the Netherlands because:

- They are not significantly different from the SDE++, in particular after the main proposed change (cap on revenues). This means that most of the current architecture can be maintained, and it could be implemented on a relatively short term (2025 or 2026);
- Solve the key issue of the current design, namely the possibility of uncapped excess profits;
- Have been proved particularly effective in solving the main problem with renewable installations, namely the bankability of projects;
- Can be designed in such a way that it takes into account electricity grid congestion issues[78] and short-term incentives for an efficient electricity system (with flexibility)
- By providing an upside (protection from insufficient market revenue) and a downside (limited possibility for additional returns) a CfD scheme may incentivise more developers and investors towards an installation without a CfD; and
- The auction design (and criteria) leaves open the possibility to steer to some extent on secondary or subobjectives.

[77] UK Government (2023). Introducing non-price factors into the Contracts for Difference scheme: call for evidence.
[78] These objectives can be, to same extent, achieved by an appropriate methodology for setting the reference price and calculation of payments. For example, a reference price calculated over large period of times (monthly average) would leave the incentive to dispatch when the market price is above the reference price. This is discussed in detail chapter 5.

Table 4-1: 2-way CfD - assessment against criteria

Category	Criteria	Score	Comments
Effectiveness: ensure continued RE expansion	Attractive profit potential	+	Closes the profit gap, but lower profit potential than SDE++
	Reduce project risks	++	Reduces revenue risk
Efficiency: minimise scheme cost per MWh of renewable energy	Support intensity	-	In case of prolonged market downturn, public support can be significant
	Limit excess profits	++	With a CfD, excess profits are almost eliminated, while the choice of the reference price may allow generators to make additional profits compared to those ensured by the strike price
Coherence - alignment with medium term electricity system objectives	Incentivising long-term contracts	+	Better incentive than in a 1-way CfD
	Short-term market price exposure	+/-	Depends on the choice of the reference price
	In line with EMR	++	Yes
Coherence - steering ability	Steer on primary objectives	++	Auctions can be sized to achieve the generation objectives
	Steer on other objectives	+/-	Some additional objectives can be pursued, although this is likely to result in a loss of efficiency (less focus on cheapest generation)
Implementation feasibility	Short term feasibility (2025/2026)	+	Yes
	Long term feasibility	++	Yes
	Administrative complexity	-	Administration similar to the SDE++ which is already relatively complex. Complexity increases slightly through added possibility of financial flows to government

++ = *very positive, -- very negative, +/- could be both, depending on design*

4.2 Option 2: PPA guarantee fund

Description

With this option, the state guarantees the default risk (i.e., risk of non-payment) of offtakers that enter long term Power Purchase Agreements (PPAs) with private generators. This option is based on the French instrument and would allow developers to obtain finance from lending institutions at reasonable terms and keep financing costs low without requiring a direct subsidy from the government. Based on current implementations, the characteristics of such a scheme would be:

- The government creates a fund that allows to guarantee a certain amount of GWh. The fund will be accessed on a first-come, first-served basis, and be a revolving funds (once a guarantee has expired, the funds can be freed up to guarantee another contract);
- The offtaker must enter a trilateral contract (the generator and the guaranteeing institution);
- The offtaker must pay a price for the guarantee (0.25% to 1% of the value of the contract). The payments from offtakers will go to increase the fund available, so that the guaranteeing institution can cover its costs and issue further guarantees;
- The guarantee will cover only a portion of the total output of the plant (up to 80%). This is so that the guarantee will not be considered State Aid.[79] Generators would sell the remaining production either via a not-guaranteed PPA or in short-term markets;

[79] EC (2021). Compensation for EIUs for the cost of financing of RES, CHP and non-peninsular territories in Spain

- The guarantee would only cover the difference between the wholesale price and the PPA price. Essentially, in case of offtaker default, generators will have to sell their energy on the market, and the guarantee fund will cover the difference between the PPA price and the market price. A “CfD clause” may establish that, if the latter is above the PPA price, the generator pays back the guarantee fund. The reference market price on which the market revenues are estimated should be set in advance in the guarantee contract; and
- The fund may cover both physical and financial PPAs. In a physical PPA, the power produced by the generator is effectively delivered to the offtaker, which will pay the generator the agreed amount and receive the agreed electricity. The offtaker would then procure any remaining power it needs from other suppliers. In a financial PPA, no sale of electricity takes place. The generator will sell its production on the wholesale market, while the offtaker will procure its power from other suppliers. However, at the end of the settlement period, the offtaker will pay the generator (or vice versa) the difference between the strike price and the reference price (similar to a CfD).

Analysis

This option scores well for most of the criteria used in this assessment, but the conclusion is negative for some key criteria, concerning the main objectives for the Netherlands. A PPA guarantee scheme does not offer additional revenues above the contract revenues. Hence, if the contract price is not sufficiently high for a positive investment decision, the project will not be realised. If market prices are expected to be below the PPA price, the demand for contracts will be significantly reduced. Thus, the government has no power to drive the demand for these contracts, and the general expectation is that their use will be limited. As such, it is not well suited to be the main policy to reach climate targets. Further, a PPA guarantee scheme cannot efficiently be steered towards additional policy objectives, because adding these will increase the price that generators can offer, and further reduce demand. However, PPAs are very effective in limiting excess profits, and a guarantee fund will allow the closure of long-term contracts also for those offtakers with insufficient credit power. Further, PPAs are in line with the proposed EMR, and the fund can be put in place in short term.

A PPA guarantee scheme provides some clear benefits to generators and offtakers, for a limited cost to the state or consumers. The main benefits of such a scheme are that:

- It would support the development of a PPA market in the Netherlands, which can contribute to progressing towards an electricity system dominated by renewables, with little market distortion (hence: efficient) in the long run, by providing more revenue certainty to generators. As the market develops, the complexity of negotiating PPAs (currently a key barrier for most potential offtakers and sellers) would decrease, incentivising further expansion;
- It allows private offtakers to participate in the energy transition, and to protect themselves against future increases in energy prices; and
- PPAs can be agreed at any time, which means deployment of renewables is not tied to government auctions, as long as the fund is sufficiently large to cover the requests.

However, there are costs and issues associated with a government PPA guarantee. Some of the issues with a PPA guarantee fund are the following:

- The guarantee may end up benefitting few private energy users in case of sustained high prices in the long term. A CfD scheme would ensure that the benefits of fixed prices are shared with energy users/taxpayers that are funding the measure;

- Some private users that access the scheme may not need it - i.e., they could invest in renewables off their balance sheet or may have access to PPAs without the state guarantee. This means that state resources end up being unnecessarily tied to cover private risks, rather than being directly invested in additional generation;
- PPAs are private contracts, which will reduce the volume of transactions in the energy markets. This has some negative effects, such as leading to less transparent prices, which discourages new entrants and weaker offtakers; and
- The interplay with CfDs needs to be well designed, so to avoid that the projects at the best locations are cherry-picking PPA structures, while remaining ones opt for CfDs. This would result in higher costs for consumers.
- In case of offtaker default (non-payment of the amounts due to the generator), the PPA contract will become equivalent to a CfD. However, as this was not auctioned, it is likely that the strike price will be significantly higher than those awarded in a CfD auction.

In their response to the EC EMR proposal, ACER and CEER indicate that they are not in favour of Member States providing state insurance for counterparty risk. According to them, this should only be done after a thorough assessment of the negative effects on other Member States and on the EU electricity market. Only if benefits surpass the cost at the EU level should these instruments be implemented. They are also of the opinion that there are existing standardised long-term products that that serve the same purpose for the offtakers; they recommend putting more effort in supporting the development of forward markets where futures and forward contracts can be exchanged.[80,81]

It is unlikely that a PPA guarantee scheme alone will be sufficient to encourage the level of solar PV and onshore wind deployment required to meet the Dutch decarbonisation targets. PPAs provide some clear benefits to private offtakers, such as long-term price certainty, robust sustainability claims, and possibly cost savings compared to buying energy directly on the market. However:

- **A PPA guarantee does not provide any additional revenue, unlike the SDE++ or a CfD** (depending on the strike price). Hence, their uptake depends on the market demand for renewable power at a sufficiently high prices;
- A guarantee fund covers a part of the revenue risk for the generator (up to 80%), and this risk would be priced in their offer. However, risks remain also for the offtaker: a fixed long-term price can be an issue if market prices decrease, in particular for businesses where energy costs are a significant share of production costs.
- Companies that want to demonstrate their green credentials often resorts to Guarantees of Origin, which are much cheaper and can be purchased more flexibly.

These are some of the factors that hinder the growth of PPAs. In 2022, 8.4 GW of capacity was installed via PPAs across Europe, while in 2021 it was 10.7 GW.[82] For comparison, in 2022, a total 789 GW of RES were installed across Europe.[83]

The uptake of the guarantee (but also of non-guaranteed PPAs) can be supported by other measures, such as the release of standard contracts and the possibility of demand pooling. Standardising PPA contracts will allow new offtakers to access this option, including those with limited understanding of the market and that lack dedicated resources. These new offtakers would also be

[80] ACER-CEER (2023). Reaction to the European Commission's public consultation on electricity market design. P 5.
[81] *Futures* are standardised contracts for the sale of electricity, traded on organized exchanges (forward markets). They have predetermined sizes, expiration dates, and delivery terms. *Forwards* are instead more customised contracts, often traded outside main markets, but that can also be resold. In the EU, forward market exists, but these are usually limited to a three-year timeframe, and they are as yet not fully developed. See for example ACER (2023). FURTHER DEVELOPMENT OF THE EU ELECTRICITY FORWARD MARKET.
[82] Taiyng News (2023). Europe Contracted 8.4 GW Renewable PPAs In 2022.
[83] IEA (2022). Renewables 2022.

reassured by the Government backing, and thus increase demand. Further, the possibility to include multiple offtakers in the contracts will allow smaller entrants to participate and will increase the pool of potential offtakers for generators, allowing them to yield better prices.

A PPA guarantee scheme is not well suited to pursue additional objectives, but it can coexist alongside another support scheme (for example, a CfD scheme) that can drive these objectives. With a properly designed CfD scheme, some generators may still be interested in selling all or part of their production via a PPA. This is because a PPA may allow them to yield better prices than they would in a CfD auction, and for a different duration. However, if additional requirements are added (for example, concerning circularity or reduced impact on grid congestion) the PPA price will increase, further reducing the attractiveness and the demand for PPA.

A PPA guarantee scheme should be limited to those actors that need the guarantee, such as enterprises with inadequate credit score. This means that large multinationals should be excluded, so that the funds can be available for actors that need it more.

Overall assessment

PPA guarantees can play a significant supporting role in supporting the development of renewables and helping to reduce the role of the state in creating demand for renewable electricity. They can also allow private consumers (as well as public bodies) to financially support the transition, as well as giving them an instrument to avoid their energy cost being left to market's volatility. However, it is unlikely that demand for PPAs will be sufficient to meet the Dutch climate targets, and it will be complicated to pursue further objectives via this scheme.

Table 4-2 PPA guarantee fund: assessment against criteria

Category	Criteria	Score	Comments
Effectiveness: ensure continued RE expansion	Attractive profit potential	--	Does not provide additional revenues – it is purely market driven
	Reduce project risks	+/-	Reduces revenue risks for the generator for the duration of the contract. However, it introduces the default risk of the offtaker
Efficiency: minimise scheme cost per MWh of renewable energy	Support intensity	+	The actual flow of state/consumer resources will be significantly less than any other option. However, in case of default, the fund may end up paying generation more than it would under an auctioned scheme
	Limit excess profits	++	As the contract is privately negotiated, profits cannot be considered excess profits
Coherence - alignment with medium term electricity system objectives	Incentivising long-term contracts	++	This is the most effective option in support of privately negotiated long-term contracts
	Short-term market price exposure	+	In physical PPAs, there is no exposure to the short-term market price. However, in financial PPAs, generators can still be incentivised to maximise the value of their production (rather than the MWh output)
	In line with EMR	++	PPAs are indicated by the EC as one of the long-term solutions MS should incentivise
Coherence - steering ability	Steer on primary objectives	--	Very limited ability to steer; left to market dynamics
	Steer on other objectives	-	Minimum requirements can be implemented, but generally left to market dynamics
Implementation feasibility	Short term feasibility (2025/2026)	+/-	A guarantee fund should be relatively easy to setup, and can be managed by a private actor with experience in PPAs guarantees
	Long term feasibility	++	Suited to support the uptake of PPAs in the long term
	Administrative complexity	+/-	The guarantee fund should be relatively easy to set up and manage

++ = *very positive, -- very negative, +/- could be both, depending on design*

4.3 Option 3: Direct investment support

Description

Direct investment support are support schemes are targeted towards reducing the initial burden of capital expenditure. There are many different types of investment support (see Section 3.2.1). Here, we discuss here mainly the direct options, which transfer a subsidy to the project developer at some point before or in the early stages after a project's commissioning. Other types that depend on specific mechanisms (such as appreciated depreciation, loans and guarantee instruments) are not considered.

Direct investment support is commonly used to promote investments for project owners with less capability of managing market risk, for example households and small businesses. The support schemes have been highly effective in this area, given that these same users tend to have less access to capital (i.e., higher financing requirements) and/or higher discount rates on future capital flows.[84] The Dutch ISDE ("*Investeringssubsidie duurzame energie en energiebesparing*") subsidies work in this format, which (until end of 2023) also covers solar panels and small wind turbines. The Dutch EIA

[84] Some research also indicates that benefits of up-front subsidies (vs. ongoing production-based subsidies) is heavily underestimated – see de Groote and Verboven (2019): Subsidies and Time Discounting in New Technology Adoption: Evidence from Solar Photovoltaic Systems

(“*Energie-investeringaftrek*”) also provides tax deductions on various sustainable energy investments for larger installations (e.g., above 15 kWp for solar panels).

Analysis

There are some design choices in direct investment support schemes:

- Support can be granted via competitive means (auctions), or to any project meeting criteria.
- The payment can be made at different times in different formats, impacting administrative burden and bankability of projects. These can be up-front, or following project investment, as a direct transfer, an ongoing payment, or a rebate on due taxes. Subsidies provided earlier are generally valued higher by project developers (about 18% more valuable).[85]
    - Following from the ability to make the subsidy transfer in different formats, the scheme is rather flexible in utilising administrative resources towards its development. For example, a tax rebate format can rely on administration within the tax authority to manage the verification and subsidy transfer process. This flexibility can be crucial in cases of budgetary limitations towards governmental bodies tasked with these policies.
- The project costs for which subsidy would be applicable must also be decided. For example, in the US federal tax incentives for solar panels, hardware (e.g., solar panels and inverters), installation costs and some indirect costs, some grid connection costs, and adequately large storage devices (above 5 kWh of capacity) can be included for the tax rebate.[86]
- Direct schemes respond well to other policies and schemes being stacked on top. For example, benefits can be differentiated based on installation type (e.g., roof-mounted vs. ground-mounted solar), impact on nature preservation, inclusion of marginalised communities, support of energy security, and the circularity of the installed hardware. Examples of this are also within the US federal tax incentives, with better rebates for projects in low-income areas and some labour requirements for projects.

A well-known example of direct support schemes is the US Federal investment tax credit (ITC). The ITC is a reduction of tax liability based on the percentage of costs of a newly installed solar system in the same year. A supplementary credit, the production tax credit (PTC), instead can provide per-kilowatt-hour tax credits for the electricity generated by the unit for the first 10 years of operation. The program began in 2006 and was recently extended into 2035 via the Inflation Reduction Act. Scope was also extended, e.g., to include some energy storage as part of solar installations. The ITC provides a tax credit amounting to 30% of the total costs of the system (scaling down to phase out in 2034, to 0% in 2036), with bonuses included for systems that benefit low-income communities. Expenses valid to be declared under this credit as part of total costs include physical equipment (solar panels, energy storage of at least 5kWh, inverters, balance-of-system equipment, transformers, circuit breakers, and others), installation costs, and some other prorated indirect costs.

The impact of the ITC in the US has been massive, helping the rate of annual solar panel installations grow by 200x since its implementation in 2006 (as of 2022).[87] While being highly effective as such, the efficiency of this policy is most likely low. Compared to the SDE++, the UK’s CfDs, and other similar programmes in the EU, the ITC is less precise in terms of the recipients, the amount, and the nature of the subsidy. Thus, the ITC is far more likely to provide excess profits on a systematic basis.

[85] Johnston (2019). Nonrefundable Tax Credits versus Grants: The Impact of Subsidy Form on the Effectiveness of Subsidies for Renewable Energy.
[86] US office of energy efficiency and renewable energy (2023). Federal Solar Tax Credits for Businesses.
[87] SEIA (n.d.) Solar Investment Tax Credit (ITC).

Direct investment support has multiple benefits, which has made it quite popular for subsidising renewables across many regions. The scheme targets one of the main financial barriers to the adoption of renewables: the high up-front costs. By directly reducing these costs, the financial viability of many projects is improved, irrespective of risk profile and forecast power market conditions. This benefit is especially valuable for the effectiveness of the scheme, in cases where potential investors have high discount rates on future cash flows.[88]

Direct schemes also have little administrative burden, and in the Dutch context, can be a low-hurdle expansion of the existing ISDE scheme. They are also rather flexible in their implementation, with regard to which capacity is used for the management, payment, and other administrative aspects of the scheme.

Direct support schemes also have serious limitations: avoiding excess profits is very challenging, they do not address revenue uncertainty, and there is little incentive not to participate. In the context of this study, the first limitation is more relevant. The amount of investment subsidy must be set well in advance for the duration of the project – assumptions made for the entire life of the project regarding the profit gap can be less precise than those made with updates possible, as with the SDE++ and other CfD schemes: where the SDE++ only project *costs* are estimated ex-ante, both the costs and highly uncertain revenues should be estimated for an investment subsidy. Many direct schemes have been designed with more or less full disregard for excess profits, e.g., in the US. Given the long-term design (and forming market expectations) from direct support schemes, clawbacks during the investment payback period of projects can drastically reduce investor confidence for future investments, increasing financing costs.

Direct schemes reduce initial capex (thus financing costs), but they have less impact on de-risking investments (reducing the ratio of financing costs to initial capex). Due to lower capital requirements, there is a very minor effect of reducing interest and internal rates of return for debt and equity in capital structure. Production risks are addressed well via production-based support schemes, such as CfDs. In cases where high price volatility is expected, these production-based support schemes can be better than direct investment support.[89] Overall, the lack of de-risking is an important missing piece for direct support of larger-scale projects.

Lastly, direct schemes leave no incentive for project developers not to participate. Given the consistent incentive for participation, the interest of participants in the scheme will not naturally diminish over time as market conditions for renewables improve. This reduces the visibility on the increasing financial feasibility of renewable projects, as measured via interest in the subsidy scheme. Meanwhile, some CfD designs allow for a transition to subsidy-free systems via reduced participation from project developers in subsidy schemes and more unsubsidised project development.

Overall assessment

Direct investment support offers a very quick, direct, and low-overhead means of setting subsidies for renewables. Yet, there are various drawbacks, and it would be a big departure from the SDE++. The scheme can be designed, developed, and implemented rather quickly, especially given an existing program for direct support. Nonetheless, much worse outcome on excess profits, inability for clawbacks, and poor investment de-risking are important caveats to consider. A further analysis of the different design options, including the mechanism for calculating the level of support, considering

[88] Some research also indicates that benefits of up-front subsidies (vs. ongoing production-based subsidies) is heavily underestimated – see de Groote and Verboven (2019): Subsidies and Time Discounting in New Technology Adoption: Evidence from Solar Photovoltaic Systems
[89] Babich et al (2020). Promoting Solar Panel Investments: Feed-in-Tariff vs. Tax-Rebate Policies.

technology neutrality (due to the different levels of unprofitable top for various technologies), and possibilities of integrating a risk reduction mechanism (which was identified as one of the main benefits of the SDE+[90]) is necessary.

Table 4-3 Direct investment support: assessment against criteria

Category	Criteria	Score	Comments
Effectiveness: ensure continued RE expansion	Attractive profit potential	++	Directly impacts the primary cost issue of renewables
	Reduce project risks	-	Very little impact on project risks/de-risking
Efficiency: minimise scheme cost per MWh of renewable energy	Support intensity	--	Unclear. On average, support intensity would probably be similar to existing SDE++: up-front subsidies are better on a per-MWh basis than production-based subsidies, but it does not reduce risk (and thus financing costs) like SDE++/CfDs do. May be more or less, depending on context
	Limit excess profits	--	Very difficult to limit excess profits compared to SDE++ and other CfDs
Coherence - alignment with medium term electricity system objectives	Incentivising long-term contracts	+	Is agnostic to participation in long term markets - projects can enter PPAs etc. after subsidy is received
	Short-term market price exposure	++	Projects remain fully exposed to market prices and/or long-term contracts
	In line with EMR	-	Direct subsidies are generally not recommended in EMR
Coherence - steering ability	Steer on primary objectives	+	Highly steerable based on need to increase/decrease impact
	Steer on other objectives	+	Lots of room to design extra elements targeting secondary objectives
Implementation feasibility	Short term feasibility (2025/2026)	+/-	Very easy to implement, given existing ISDE scheme
	Long term feasibility	++	Very easy to implement in long term
	Administrative complexity	+	Very simple, existing process in ISDE

++ = *very positive, -- very negative, +/- could be both, depending on design*

4.4 Option 4: Tradeable CfD (capability-based CfD)

Description

This option is an evolution of the traditional CfD, where the contract is standardised and tradeable; i.e., the buyer (in this case the state) has the right to resell the title. The contract is financial (no sale of electricity takes place) and is otherwise similar to a financial CfD or PPA. These contracts will be at fixed delivery price, with a 1-year maturity, and have final settlement, which means that:

- Similar to standard 2-way CfD:
  The buyer will have a guaranteed price for the duration and the quantity of power established in the contract (e.g., 1 MW capacity in year 202x for €50 per MWh generated);
  The generator will have the same rights and obligations as in a standard CfD contract, although the counterparty for part of the contract may change over the lifetime of the contract.
- Different from standard 2-way CfD:
  The state will pay or receive from the buyer and the generator, as per the new contract;
  The contracts will be settled at the end of the reference period (annually).

[90] Trinomics (2021). Evaluatie SDE+.

The sale price of the contracts can be different from the original price, but the government's ideal strategy would be to sell only when the selling price is higher than the contract's original price. It is likely that a 15-year contract for the delivery of electricity would be cheaper than a contract with shorter maturity as the seller is likely to give a discount for longer term revenue certainty. The state may sell:

- At standard terms (e.g., demand a premium on the strike price in exchange for the guarantee).
- In an open market, which includes other sellers. These may be generators that choose to sell part of their generation via PPAs, and where a buyer may decide to resell its contract in case its situation or its expectation for future prices have changed.
- Via auctions, where the market for contracts with a longer end date (maturity) does not exist.[91] The reserve price will be the CfD price.

While the contracts will have a standard 1-year duration, the state would choose how many years in advance these could be sold. For example, CfDs for the following 10 years could be presented for sale at the same time.

Tradeable CfDs should be seen as a hybrid measure between government direct support and market creation mechanisms. Box 4 provides an example.

Box 4: Example tradeable CfD

Imagine:

1. A 2-way tradeable CfD with a wind generator for 10 MW for 15 years at €50/MWh. The generator and the state sign a contract in 150 parts (1 contract per MW per year).
2. The state puts 1MW contracts with a 1-year maturity for sale. We assume these are sold at a price of €55/MWh.
3. Each buyer will receive about 3 500 MWh of power during the year, for a cost of about €190 000.
4. If the reference market price for the following year is €75/MWh, the generator is left with €87 600 additional revenues, that it will have to pay back. The buyer will receive €70 080 from the generator, while the state will receive the remaining €17 500. If the market price is €25/MWh, then the buyer will pay the generator €70 080 and the State €17 500, as the low market price will give the buyer €87 600 worth of additional revenues.

If the CfD was not resold, the government's cost would have varied from –€87 600 to +€87 600. Reselling the CfD on the market means that the government outcome is significantly less volatile, and it is limited to the difference between the strike price and the resale price. While in a traditional CfD the government may have to set aside reserves for €87 600, with a tradeable CfD these would only be for €17 500 (based on the estimated price range for the duration of the contract).

To ensure that these contracts are appealing to generators and small buyers, some provisions could be considered. For example, the state could keep guaranteeing the contract for the generator in case of buyer defaults and should — at least initially — agree to buy back contracts from private buyers in particular situations. Further provisions are:

- The original contract should still be awarded via competitive auctions (involving both solar PV and onshore wind). The auction will not be based on a specific plant, but on MWh of production. This means that the generator can set a contract only for part of their capacity and can choose to sell the remaining capacity in the market.
- The payments should be calculated on a reference plant, rather than on the actual energy provided to the market. This would provide generators with the right incentives to maximise

[91] See previous section, footnote 81. Currently, generators and suppliers/large consumers are able to trade contracts with longer end date on regulated markets called forward markets, but these contracts usually extend only up to three years. However, if only the state is able to offer contracts with longer maturity, an auction is a more efficient way to sell these contracts.

revenues by optimising operations and would ensure that the tradeable CfD becomes a commodity.[92] Payments could be estimated as the net of these two flows:

1. Payment to generator: The state/buyer pays a fixed, inflation-indexed, hourly remuneration to the counterparty, independent of actual production in these hours. The level of the hourly remuneration is determined competitively in the initial procurement auction.
2. Payment to the government: The generator pays to the State the hourly revenues of a reference generator for the same technology. Other factors could provide further breakdowns, such as location and size of the installation. The revenues of a reference generator are defined as the day-ahead spot price (or zero, if negative) multiplied with the hourly output of a reference generator. This is not the hourly output of the specific asset (i.e., the CfD is not “as produced").[93]

Analysis

While a tradeable CfD offers some interesting advantages compared to traditional CfDs, there are significant uncertainties concerning its effectiveness and its feasibility. The assessment against the criteria used for this study suggests that tradeable CfDs are positive except for feasibility, administrative complexity and the possibility to include secondary objectives. The assessment is generally positive for the remaining ones, and in particular for supporting an early exit of the state from the energy market (in a traditional CfD and SDE++ support, the state is locked into a contract for 15 years. The tradeable CfDs offer the state the option to sell contracts to third parties, releasing it from the obligation).

The tradability of the contract has some significant advantages. Compared to a traditional CfD scheme, a “tradeable” CfD has three main advantages:

1. It supports the participation of private actors in the energy transition;
2. It frees up government resources, so that these can be directed towards supporting the technologies most in need, rather than solar PV and onshore wind.
3. It reintroduces some liquidity in short and long-term markets. While this is not a significant problem now, in a future where a majority of generation is under a CfDs, suppliers and large users may find difficult to find sufficient capacity to cover their long-term needs.

However, a tradeable CfD is an unproven and rather complex approach, which means some of its main drawbacks may not be evident yet. As far as we can ascertain, no country has attempted or considered this approach. While the Netherlands has a financial sector fully able to deal with the complexity of such an instrument, the government management of the scheme and its risks cannot be fully assessed yet.

It is unclear whether there will be demand for buying government CfDs. The demand for these 1-year contracts will depend on consumers expectations for future energy prices, and it would attract those that expect to pay a market price above the strike price for the period covered by the title. However, if the strike price is above the expected market price, the demand for these contracts will be low or non-existent.

[92] For example, generators will be incentivised to plan “down time” for maintenance according when market prices are low. In some cases, generators may also incentivised to make additional or different investments, for example west-facing PVs (to maximise export during evening hours, when demand is higher and output from most PVs is starting to decline) or on-site storage systems.
[93] EconStor: Financial Wind CfDs

If there is demand, this would be for the cheapest contracts, which means the state would be left only with the more expensive CfDs. In case of market prices above strike price, in a traditional CfD the state will receive a revenue stream from the generator, which then can be reinvested or distributed back to consumers or taxpayers. In a tradeable CfD, these contracts will be in the hands of private owners, which would be the ones benefitting from the high market prices. While this can be considered an issue (the consumer is likely to lose out in case of high market prices), it would also mean that the support scheme would retake some more traditional objectives: supporting unprofitable technologies and applications. With a traditional CfD, the state acts as an intermediary that hedges all consumers against future high energy prices. Some may argue that this intermediary role is beyond the role of the state, and that market actors should be able to provide this service.

The administrative complexity may be significant. Instead of managing one contract per installation, a tradeable CfD scheme will require the state (or an organisation set for this purpose) to manage several contracts for each installation, including for the part concerning the resale (via auctions or other means). Further, complex rules should be put in place to ensure that the generator is effectively producing and delivering value (given that payments are not related to generation).

Tradeable CfDs may reduce the sale of long-term contracts, such as PPAs or futures, but it may also support the development of the long-term market that futures or PPA can use to further expand. If tradeable CfDs for the duration of 1 year and different maturity go on sale, the demand for PPAs or futures may be significantly affected, as these contracts tend to be more rigid. It is also possible that the sale of CfDs may depress the price generators are able to ask, reducing their incentive to go for routes other than the government scheme. However, it is also possible that the sale of CfDs may create the space for generators to sell similar contracts outside the government scheme, as well as giving buyers the possibility to resell their title in case their situation changes. Another benefit of a government-led sale could be the transparency in prices, which will give more confidence to private buyers.

Estimating the generation for the reference plant may be rather complex. The calculation of output from the reference plant may be complicated and has a large impact on the payouts. For example, how to deal with outages and significant under delivery? As the contracts are denominated in MWh, how to reconcile the production of a plant that generates significantly less? How to deal with moving averages from the average plant? Monitoring and a clear methodology should be established to define the output of the reference plant.

The number of options to include additional objectives (public acceptance, nature inclusiveness and circularity) in the scheme is reduced. Using the reference plant as the basis for the payment ensures that generators will aim to maximise their revenues from sales in the wholesale market (addressing concerns with spatial planning and optimal dispatch strategies). However, if additional elements are included in the scheme, either as minimum requirement or as scoring criteria, the price per MWh of the winning installations would increase (higher strike prices). At the moment the CfDs are put on sale, the higher prices would be reflected in higher costs for potential buyers for the CfDs, which would reduce the demand. As described further down in 4.5, there are options to reward the achievement of these objectives via means that do not affect the strike price (or that do not affect the cost of generation only of those plants involved in the scheme).

Overall assessment

The introduction of tradeable CfDs may have some significant benefits, such as support the creation of a long-term market for energy contracts, which may accelerate the transition to a market where government support is not necessary. However, being a completely new approach, it will require time and careful considerations before it is undertaken. Therefore, it is recommended to continue exploring the solution together with stakeholders for the medium term, while opting for a more established solution, such as traditional CfDs, for the short term.

Table 4-4 Tradeable CfD: assessment against criteria

Category	Criteria	Score	Comments
Effectiveness: ensure continued RE expansion	Attractive profit potential	+	As in a traditional CfD, any profit gap for renewable generator will be avoided by setting the appropriate price to achieve the required returns. However, profit potential remains below SDE++
	Reduce project risks	++	Revenue risk is eliminated
Efficiency: minimise scheme cost per MWh of renewable energy	Support intensity	+/-	Similar to CfDs, support intensity can be high for low market price, and low for high market prices. However, this option gives the State the opportunity to pass through this risk to third parties
	Limit excess profits	+	Given the strike price will be fixed, only additional profits can be made by selling at different times or on different markets compared to the reference market. However, excess profits may be realised when production is significantly below the production from the reference plant (unless appropriate rules are in place, the generator may be paid even if it does not generate)
Coherence - alignment with medium term electricity system objectives	Incentivising long-term contracts	++	The availability of the resold CfDs may support the development of markets for these products
	Short-term market price exposure	++	Due to the payments being unrelated to production, generators are fully expose to short-term markets, and have an incentive in maximising their revenues in these markets
	In line with EMR	+	This type of CfDs were not specifically discussed in the EMR proposal, but they offer the same protection to consumers the EMR aimed at
Coherence - steering ability	Steer on primary objectives	+/-	Unclear at this stage
	Steer on other objectives	+/-	Unclear at this stage
Implementation feasibility	Short term feasibility (2025/2026)	--	Unlikely to be implementable in the short term
	Long term feasibility	+/-	Unclear at this stage
	Administrative complexity	--	Possibly high, depending on implementation details.

++ = very positive, -- very negative, +/- could be both, depending on design

4.5 Addressing subobjectives & secondary objectives in the four options

All options can take subobjectives and secondary objectives into account. However, the extent to which different options allow to steer on different policy objectives *within* an instrument varies.
The first conclusion is that all options can take subobjectives (incentivise an efficient electricity system & address grid congestion) and secondary objectives (on nature, spatial planning, circularity and local participation) into account by implementing minimum requirements. This conclusion on minimum requirements does not come as a surprise. Yet, it is relevant input to answer our second research question: *To what extent can the proposed options take potential other subobjectives into account, such as grid capacity, spatial integration, public acceptance, nature inclusiveness and circularity?* In this section, we elaborate on the extent to which instruments differ in allowing steering on sub and secondary objectives, and we distinguish objectives based on their characteristics.

The 1st distinction is the extent to which an objective involves generic vs. specific characteristics. Pursuing objectives with specific characteristics in generic instruments lowers the effectiveness. All considered support options are generic instruments. While this has evident administrative benefits, the consequence is that project (or e.g., location) specific circumstances cannot be addressed adequately within the instruments. These include issues like *specific* nature measures, tailored for a certain location (it does not include *generic* nature measures, such as an increased minimum distance between solar panels). Only if the benefits of such measures can be assessed via a general rule, it can be integrated in a generic system. The fact that generic issues can be integrated in the support options, does not mean that this is desirable: the benefits should be weighed against the costs. It is likely that pursuing secondary objectives lowers the effectiveness on the main (climate) objective, which may not be the case if the secondary objective is pursued outside the support scheme.

The 2nd distinction is the impact of objectives on the project's core operations and financials:

A. **Objectives that do not affect a project at all** are not relevant for the instrument's design.
B. **Objectives that affect the investment costs, but not the operations**, such as solar panels and/or wind turbines with better circularity characteristics, certain nature and landscaping measures, or local participation (if it leads to higher CAPEX).
C. **Objectives that affect the operations (and investments costs)**, such as increasing the distance between (ground mounted) solar PV panels, cable pooling and integrating storage.

In the absence of additional policies, options that offer additional revenues (2-way CfDs and investment support) can steer more direct on any objective, compared to market options (PPAs). Options that only address certain financial risks (PPAs and tradeable CfDs), and are thus more market-based, can only do so to a limited extent without complementary policies. While each option can integrate minimum requirements, requirements that negatively affect the project's business case (B and C in the above list) will result in less project development under options that do not allow to provide additional revenues to compensate the additional costs resulting from the minimum requirements. For instance, it is unlikely that the average PPA offtaker would be willing to pay a cost premium resulting from minimum requirements, as the offtaker can also choose to buy electricity on the short-term market. Options that can offer additional revenues can take cost increases into account and adjust their policies in various ways, for instance by reflecting these costs in the strike price.

Objectives that only affect the investment costs are the easiest to address and can be addressed in all instruments (alone, or in combination with investment support). In the case of solar panels and wind turbines with improved circularity (or the same for equipment produced under decent working conditions), for instance, investment support can be used to recover (a part of) the surplus cost of the hardware. Hence, both a PPA guarantee fund, a tradeable CfD or a regular 2-way CfD can be combined with a form of investment support for this. However, it can also be integrated in OPEX support. In a 2-way CfD, for instance, the strike price can be adjusted upwards, to consider additional CAPEX for circular hardware (amongst others). Objectives that affect operational income are more complex to address and may fit better with operational support instruments.

To conclude: all options can consider other objectives, as long as requirements can be defined. Options that allow to offer additional revenues can steer more proactively *inside* an instrument. We did not assess options to steer on sub or secondary objectives outside the policy instrument. The fact that certain options do not allow to steer effectively on certain objectives does not imply that an option should not be considered; instruments can be combined with other instruments that can be used for additional costs related resulting from pursuing sub or secondary objectives. In theory, each option can be combined with a form of investment support, which can be used to cover the costs to meet specific requirements. However, this may not be necessary, as operational support can easily be adjusted to consider additional CAPEX as well. Whether or not steering towards specific objectives within the instrument is more effective than outside, and the extent to which potential benefits warrant the costs (decreased effectiveness) has not been assessed in this research.

5 First considerations for a 2-way CfD design

The functioning of a 2-way CfD scheme depends to a large extent on the design choices. Hence, the effectiveness, efficiency, and coherence depend on those choices. This section explores some of the key design choices for a 2-way CfD instrument in the Netherlands. This section does not aim to provide conclusive and exhaustive findings about the preferred design choices but aims to provide a first direction for further needed research into the detailed 2-way CfD design; we identify certain key design elements. Since these design choices can have a large influence on the effectiveness and outcomes of the scheme, further in-depth analysis outside the scope of this analysis is needed.

Financial vs physical contracts

The difference between the two options is the nature of the contract. In the first case (financial; not to be confused with tradeable 2-way CfD), no sale of electricity takes place. The generator will sell their electricity on the wholesale energy market, and the payment is based on the difference between the reference price and the strike price. The reference price is not necessarily the actual sale price (see option below). On the physical option, the electricity is sold to the buyer (the state, in case of state backed CfDs), which then can resell it or use it. In this case, like in a PPA contract, the payments are fixed from the buyer to the generator, for the established price. The vast majority of CfD support schemes are of the financial type (no trading of electricity takes place), including the SDE++.

Single price vs range

In a typical CfD contract, the strike price is agreed beforehand and is fixed for the entire period (either in nominal terms or adjusted to some extent for inflation). However, it is possible to set a range around the strike price, so that payments to or from the generators are triggered when different wholesale prices are reached.

In essence, there are multiple ways to set a price range, especially for the downward range:

- **Option 1: Single strike price, with a bottom price** under which no payments take place. This is similar to the bottom price in the SDE++: at moments of very low prices, the maximum reimbursement is equal to the strike price minus the price floor. Hence, developers take on the price risk in case of *low* prices. Reducing this downward price risk limits the maximum payout for the government and hence reduces the maximum budget reservation for the scheme. On the other hand, generators can keep revenues up to a certain price ceiling and have to pay back revenues above the price.
- **Option 2: Price range in which generators take on all price risk**: In this case, generators take on the downward risk up until a certain bottom price. Below the bottom price, revenue is reimbursed by the government. This is quite different to the current SDE++ and actually leads to governments taking the risk in case of very low prices, while in the SDE++ this is the other way around. For the price ceiling, it is similar to the situation above, since the objective is that developers do not keep revenue at very high prices.

One could also design the bid for a range in multiple ways:

- **Bid for a single strike price**, with an administratively set upward and downward range: This is most likely easier to implement in an auction format and ensures a simpler ranking mechanism of bids. The upward and downward range do not necessarily have to be equal.
- **Bid for both the price floor and ceiling:** In this way you provide flexibility to generators design their preferred range and risk distribution. However, it would be complex to objectively assess and rank different bids in an auction.

The advantages of a range compared to a single strike price is that generators retain some of the price risk, instead of transferring it entirely to the state (or consumers), which means that they may earn additional revenues in the right market conditions. Thus, with a range, the state and generator share the price risk. For budgeting reasons, one could continue a (low) price floor similar to the SDE++ ('basisprijs') to reduce the required budget reservations for the support scheme. One could argue a similar upward price range in which generators can retain some revenues above the strike price is logical to compensate for the downside risk generators also experience.

However, the impact of a range in the overall cost-effectiveness is unclear. if generators can bid for their preferred range, in theory generators will offer a range in which the midpoint represents their required return and a range to reflect their risk propensity. However, risk-averse investors will want to ensure they reach a minimum required return on their project, and this will correspond to the price floor of their offer. This is likely to be very close to the price offered into a single-price CfD auction, which means that consumers will have limited advantages compared to a single strike price. Setting the range administratively brings other downsides. Most notably, the chosen profile of this range might not suit all types of developers and can favour certain types and sizes of developers; in general, large developers that finance from the balance sheet are more tolerant of risks, and can bid for riskier ranges.

Payment calculations

A key issue with early implementations of CfDs are design elements that incentivise a generate-and-forget approach, which leads to market distortions such as generation below marginal cost, inefficient dispatch, and negative prices more often than necessary. The SDE++ over the years has already implemented notable improvements, but it is still an important design choice that could be further improved.

- The choice of the **reference price** can have a significant impact on the effectiveness of the scheme and in solving some of the issues seen in early implementations of CfDs across Europe. A reference price calculated, e.g., hourly and on the day ahead price, would not provide any incentive for generators to adopt practices that minimise total system costs, such as generating only when the market price is higher than marginal cost, or planning downtime (for example, for maintenance) when the market price is low. On the other hand, if the reference price is averaged over a longer period (e.g., unweighted annual average of day-ahead price is used in the SDE++) generators have an incentive to generate when the market price is higher than the reference price.
- Concerning the **reference period**, the payment can be calculated based on price differentials for each hour in which the plant was generating, or over longer time periods (daily, monthly). In general, the longer the period, the more incentive generators will have to "beat the reference", i.e., receive more revenue from the market than the average generator would yield over the reference period. However, the incentive for generator has a symmetrical element, in that generators may end up with lower revenues compared to the revenues estimated by the reference price over the period.
- Concerning **reference volumes**, we consider actual vs. estimated output. To date, the majority of CfDs schemes implemented calculated the payments due to or from the generator based on the quantities injected into the network[94]. However, new options are being discussed to instead use a methodology to estimate the output volumes, and these aim to provide the same incentives as discussed in regard to the reference price: generators would be incentivised to maximise the value (price x volume) of their output, rather than only the

[94] In contrast, in the SDE++ both self-consumption and grid delivery are eligible for subsidy.

volume, and therefore deliver higher system benefits. For example, Schlecht et al.[95] suggest estimating the top-up or clawback payments based on a typical plant of the same technology, while Newbery[96] suggests a CfD 'with hourly contracted volume proportional to local renewable output/MW, with a life specified in MWh/MW, adjusted for regional variations in correlation with total renewable output'.

- **Payment limits** are to ensure control over the total cost of the scheme. Payments could be suspended when market prices are negative, limited to a maximum lifetime amount per installation. The SDE++ already includes these limits.
- To minimise the **flow of funds** between generators and the government counterpart, payments to generators should happen regularly (currently in SDE++ once per year), but payments from generators to the government could be netted from future payments and then settled possibly over longer periods (in Poland it is currently per 3 years).[97]
- **Inflation indexation** can be considered as inflation can be a significant challenge for bidders in two different ways:
  1. If inflation is high, the cost estimates made at the moment of submitting a bid may be significantly lower than the realisation costs; and
  2. If the strike price is not indexed, generators must estimate the increase in OPEX they may have during the lifetime of the contract and increase the strike price to account for that.

  For this reason, some CfD schemes adjust for inflation. It is possible to adjust one time for inflation (or price increases and decreases) at the project start to correct only CAPEX cost changes, or to adjust also for inflation impact on OPEX. The SDE++ currently does not adjust for inflation, meaning inflation risk is fully taken on by the developer.

Financing and administration

Two other important administrative design elements when setting up a CfD scheme that are not further analysed in this chapter is who **oversees** the scheme (currently RVO with the SDE++, but there are options, e.g., the UK with the LCCC) and where the **funding** for the measure comes from (currently via general budget with SDE++).

Tendering method

In order to setup a CfD scheme, the offering body needs a method to select the most advantageous proposals. While in the past several countries have opted for administratively set price or direct negotiations, currently the recommended approach (also by the EU) is to select winners via an auction. There are several elements of the auction format that may have a significant impact on the outcome. Such as: sealed vs. public bids, pay-as-clear vs. pay-as-bid[98], and maximum strike price vs. no maximum strike price. The current SDE++ auction is pay-as-clear with sealed bids and an administratively set maximum strike price (basisbedrag).

It is also important to decide whether to opt for a single pot or technology-differentiated pots. To award CfDs, the offering body needs to setup either a maximum budget (maximum amount of exposure) or a maximum amount of capacity (generation) it wants to procure. For the case in consideration, a specific pot for solar PV and onshore wind (together) is inevitable if other technologies are still supported by the SDE++, a 1-way CfD. This is a significant change compared to the current technology-neutral single pot setup. Other elements could be kept in line with the current SDE++. Depending on

[95] Schlecht et al. (2022). Financial Wind CfDs.
[96] Newbery (2021). Designing an incentive-compatible efficient Renewable Electricity Support Scheme.
[97] PWEA (2021). Quick guide to the Polish Renewable energy Auction System.
[98] A pay-as-clear auction sets the same clearing price, equal to the highest cleared price, for all bids, including those cleared at a lower price than the clearing price. A pay-as-bid auction sets the clearing price for each bid as the original bid price, i.e. higher bids (if cleared) receive higher clearing prices. More details can be found in this presentation (Accessed 29 September, 2023).

the eventual differences in design choices between the support for solar and wind and the SDE++, it could be decided to have a separate scheme for solar and wind or to integrate it within the SDE++ to some extent. The maximum strike price could stay technology-specific and be further differentiated within technologies, similar to the SDE++. Another possibility is to introduce a separate pot for solar and onshore wind that includes additional conditions (for example, the minimum qualifying criteria for a separate pot would be more difficult to attain than for the main one). The next paragraph proposes methods to deal with additional criteria.

Setting a sufficiently 'tight' auction budget is key to increase efficiency of the bids. One key mechanism that increases cost efficiency in the SDE++ is a budget that makes sure that developers have an incentive to bid low, while still making sure sufficient volume or capacity are auctioned. In the evaluation of the SDE+ Trinomics showed this mechanism and the possibility to bid below the strike price (until 2020 the 'vrije categorie') increased efficiency of the scheme.[99] Currently there is one common budget, but if due to the 2-way CfD design a separate solar and/or wind budget is needed, budget dynamics will change. A too tight budget will mean the most expensive solar and wind project categories will not receive subsidy, while these could also be the categories that are favourable when considering secondary objectives. A budget that is too large will take away the incentive for competitive bids, especially for categories with a lower basisbedrag.

Introducing additional criteria

The SDE++ is a single-criterion auction, where the price for each tonne of GHG emissions saved is the only award criterion, although the support contracts and payments are then calculated on MWh generated, with a ceiling on the total amount of generation that can be supported for every project. Other CfD schemes usually choose the winner based on the price per MWh of renewable energy generated, but then set a contract based on the MW installed and do not put a ceiling to the amount that can be generated and supported. This is in line with the fact that the main objective of these schemes is to support the generation of the largest amount of renewable energy.

However, as the amount of RES in the system increases, several issues (such as system integration challenges and public acceptance) are emerging (see section 2.1, 2.2 and 4.5). To deal with these, most countries include *regulation* and *qualification requirements* (refer to table 5-1, first part). Other countries have attempted to integrate these non-price factors in their support scheme directly within the auction methodology (shown in table 5-1, second part). For example, France includes non-price factors counting up to 25% of the final score in current tender for offshore wind in Normandy,[100] while the UK is currently considering the introduction of non-price factors into the CfD scheme.[101] The UK proposal considers options to include these as part of the winners selection process (bid re-ranking, amending the evaluation formula) and post selection ("top-up" to the CfD strike price). Already in the Netherlands, non-price criteria were used for offshore wind contract awarding at the "Site VII" of the Hollandse Kust West (HKW) and at Ijmuiden Ver.[102]

[99] Trinomics (2021). *Evaluatie SDE+*.
[100] 4C Offshore (2022). Bidding Window Closes for First French Tender in Three Years.
[101] UK Government (2023). Introducing non-price factors into the Contracts for Difference scheme: call for evidence. and UK government (2023). Contracts for Difference for Low Carbon Electricity Generation.
[102] Wind Europe (2022). Europe's latest offshore auction mainly using non-price criteria is a success.

Table 5-1 How can additional criteria be included?

In/outside	Instrument	Explanation
Outside the support mechanisms	Regulation	Everybody must comply, usually it has the drawback of not incentivising any behaviour beyond minimum compliance.
	Targeted schemes	These may provide additional revenues for generators. For example, a grant for supporting circular investments.
Within the support mechanisms	Pre-qualification requirement	Equivalent to regulation but targeted only at scheme's participants. The requirements can either be met or not, which means they should not be too strict (as this would reduce the number of participants) but keeping them too lax means also little would be achieved, as there is no incentive to go beyond the minimum.
	Part of the winner selection process	Affects the ranking of bidders according to factors other than price. Based on the weight on the total score that the additional criteria are awarded, they can be given more or less importance. This approach often favours projects that achieve a good balance among the different factors, rather than those who are the best in a single one.
	Post selection	Does not affect the ranking (so the cheaper will always be chosen), but may increase costs or benefits for the winners, and it is applied afterwards. For example, a price correction may be applied after the ranking has been completed. The chosen projects may get extra or less revenue per kWh based on these criteria.

Generally speaking, the inclusion of additional criteria (beyond the minimum required by law for all projects of the same nature) will result in more expensive projects and in higher complexity in managing the auction process. However, this may be justified when the costs are estimated to be less than the benefits of the approach. There are a number of considerations that can be made concerning the design of auctions that accounts to the additional objectives described in section 4.5.

System integration can be broken down into several sub-objectives:

- **Optimisation of dispatching choices** (including siting/orientation) could be achieved by selecting an appropriate top-up price methodology, rather than via auction. Optimisation includes elements such as the choice of the appropriate reference market, reference period, and other conditions (e.g., no payment in case of negative prices, which is already implemented from 2023 in the SDE++). An appropriate reference price will leave generators the opportunity to "beat the reference price", i.e., selling when prices are higher. This will also influence orientation choices for solar PV and siting for onshore wind. For example, the reference price for solar would be low during peak generation hours but increase during the morning and evening peak. An east- or west-facing solar PV array will be able to reap higher market prices compared to the reference price, but still receive the same top-up payments as other solar plants. Similarly, an onshore wind farm located in a less windy location may benefit from generating when prevailing winds are not blowing.
- **Spatial integration and grid congestion**: while a certain site may be optimal because of its wind or solar exposure, it may require a connection to an already congested part of the grid. Usually, the participation to a public auction requires a previous connection agreement, which can be refused when the network is not able to sustain.
- **System adequacy and security of supply** are the responsibility of the System Operator and are better solved via dedicated measures. However, provisions can be made to allow installations supported by the renewable auctions to participate in these markets, for example they can be favoured for the installation of a network-connected storage device.

Public acceptance, nature inclusivity and circularity: for these additional objectives, it is less clear what is the best approach. They all can be brought in the auction process either as a *pre-qualification requirement*, as *Part of the winner selection* process or in *Post selection*, but with the identified downsides. Therefore, options to address these objectives outside the auction mechanisms should also be considered.

Penalties for failure to deliver or late delivery

Many CfDs schemes in place in Europe include penalties for non-delivery or late delivery. This is because in the past some bidders have decided to withdraw from the construction after the construction costs became clearer, or when inflation meant their costs spiralled up. In some cases, bidders went on purpose under-price, hoping for a decrease in costs to happen between the winning of the auction and the delivery date. Withdrawing after winning has clear negative consequences for meeting the deployment targets and for the excluded bidders. Such behaviours could be excluded with appropriate rules. For example, bidders that do not complete their project could be excluded from participating in other auctions for a certain period. In the SDE++ there currently is a maximum implementation period. if a project is delayed, the support period is reduced by the delay period. There is no further penalty for non-realisation.

Design elements to stimulate private long-term market development

To further incentivise private market development, several design elements could be potentially added. The CfD scheme could allow generators to only contract part of their generation via CfDs and keep a portion to be sold on the market or via PPAs. This solution was adopted in the Spanish CfD scheme, where projects "*must sell a defined amount of electricity to the market under the CfD contract, but once the threshold is reached, they can either opt to continue selling their electricity under the CfD or, for example, sign corporate renewable power purchase agreements (PPAs) with industrial customers*".[103,104] Another option, as in Poland, is to give generators the freedom to adjust every year the production volume falling under the CfD contract. This option is more financially beneficial for developers and less beneficial for the government. Another option is to propose a one-time possibility for generators to leave the scheme. This is also beneficial for developers but can also lead to lower efficiency of the scheme, since after leaving the scheme developers can in theory earn large profits, while having been subsidized in earlier phases of the project.

[103] Balkan Green Energy News (2021). Spain gets Europe's lowest wind energy price with CfD auction model.
[104] Energy post (2021). Do government renewable energy auctions squeeze the PPA market?

6 Conclusions

Our conclusions are split in four blocks:

1. The most suitable support system for solar PV & onshore wind in the Netherlands;
2. Possible design choices for a 2-way CfD;
3. The role of system cost in support schemes; and
4. The role of secondary objectives in support schemes.

1: The most suited support system for solar PV & onshore wind in the Netherlands

A 2-way CfD, if well designed, is the most suited system to guarantee efficient and sufficient investment in solar PV and onshore wind beyond 2025.

In our analysis of potential instruments for solar PV and onshore wind in the Netherlands from 2025 onwards, we identified twelve criteria to assess future policy instruments against, based on our assessment of relevant policy objectives, and our expertise on EU and Dutch (renewable) energy policies and markets. In chapter 2, we concluded that the main objective is to continue expanding solar PV and onshore wind deployment at a similar pace towards 2030 and beyond. While an in-depth assessment of the business case of solar PV and onshore wind projects is out of scope, we argue that moving away from support instruments in 2025 or 2026 creates a major risk to slow down the investment pace. For that reason, our analysis focused on support instruments. The different options are described in Chapter 3, based on literature and a scan of instruments abroad. In Chapter 4, we focussed on four of the most relevant options, selected based on the criteria. Table 6-1 summarises this assessment. We only studied solar PV and onshore wind. Our conclusions are not applicable to other technologies in the SDE++; other technologies have other characteristics (e.g., higher OPEX costs) and/or are in a different development stage (e.g., renewable hydrogen).

Table 6-1 Summary assessment of options against criteria

Category	Criterion	1-way Contract for Difference (SDE++)	2-way CfD	PPA guarantee fund	Direct investment support	Tradeable CfD
Effectiveness: ensure continued RE expansion	Attractive profit potential	++	+	--	++	+
	Reduce project risks	++	++	+/-	-	++
Efficiency: minimise scheme cost RE per MWh	Support intensity	--	-	+	--	+/-
	Limit excess profits	-	++	++	--	+
Coherence - alignment with medium term electricity system objectives	Incentivising long-term contracts	-	+	++	+	++
	Short-term market price exposure	+/-	+/-	+	++	++
	In line with EMR	--	++	++	-	+
Coherence - steering ability	Steer on primary objectives	++	++	--	+	+/-
	Steer on other objectives	+/-	+/-	-	+	+/-
Implementation feasibility	Short term feasibility	n/a	+	+/-	+/-	--
	Long term feasibility	n/a	++	++	++	+/-
	Administrative complexity	+/-	-	+/-	+	--

++ = very positive, -- very negative, +/- could be both, depending on design. In the table we compare what could be done in the type of options. For example, the 1-way CfD option is not necessarily what is currently done in the SDE++ but what could be done within the instrument being a 1-way CfD.

We identified two options that seem implementable on the short term: a 2-way CfD and a PPA guarantee fund. Among these two, a 2-way CfD performs best on the key criteria. Regarding **effectiveness**, a 2-way CfD allows to close potential profit gaps (depending on the level of the strike price) and to reduce a project's exposure to electricity price risks (and thus reducing financing costs and total costs). Regarding **efficiency**, a 2-way CfD allows for lower support intensity compared to a 1-way CfD (i.e., the SDE++), due to the revenue ceiling. This revenue ceiling also reduces excess profits risks, as deemed relevant. However, depending on the design details, the revenue ceiling could reduce overall investments, compared to a 1-way CfD. The main disadvantage of 2-way CfDs are that they do not incentivise long-term *private* contract markets as it may be too attractive to stay in the 2-way CfD. As a result, government and electricity generators are likely stuck to 15-year contracts. However, a 2-way CfD provides more of an incentive than a 1-way CfDs, which could make phasing-out easier.[105] In addition, when not well-designed, 2-way CfDs may distort the exposure to short term price signals, which leads to inefficient situations at system level (e.g., vastly higher than necessary costs for grid expansions). However, when designed well, these risks can be mitigated to some extent. Whether this will result in sufficient new investments depends on the design choices in the new system.

A PPA guarantee fund does not perform well on effectiveness, as project development efforts would be entirely left to market dynamics (the demand for a given PPA-price). In a CfD, the maximum strike price is set by the government, which can take into account various elements (e.g., production costs, climate goals, secondary objectives etc.) In contrast, the PPA price is set based on the negotiations between the generator and the offtaker. While in specific cases, an offtaker may be willing to pay a premium on top of the expected market price (e.g., a datacentre for a global IT-company), the average offtaker will not pay more than the expected market price. If the expected market price is too low for a profitable business case for the project developer, the project will not be realised. Hence, a PPA guarantee fund does not allow to steer on renewable energy deployment pace within the instrument and is thus ineffective. Further research on the combination of a CfD with a PPA guarantee fund would be required to identify the added value of a fund as an additional instrument. Other topics, such as demand pooling, could also be further explored.

Since it is very unlikely that a PPA guarantee fund alone will result in the required project development pace for the 2030 targets, a 2-way CfD scheme seems the best suited option. While we did not perform an in-depth analysis on the question if the Dutch government can rely on market dynamics alone to meet the required pace of project development to meet their targets, in previous research (between 2020-2022), we concluded that many projects were not expected to meet the required returns for a positive investment decision in the absence of the SDE++. Since then, we have observed various elements that affect business cases in different ways. These include elements that affect the business case in a negative way (e.g., temporary cost increases due to supply chain disruptions, higher interest rates, a push for more quality and more revenue cannibalisation) as well as in positive way (increased average electricity prices, increased demand and expected declining investment costs). Given the different effects, we conclude that relying on market dynamics would lead to a significant risk of not meeting the required pace of project development. A PPA fund can help unlock more private potential. However, it is unlikely to ensure a sufficient project development. Adjusting the SDE++ for solar PV and onshore wind to a 2-way CfD appears to be a solid option in the short run, scoring well on effectiveness and efficiency. No better alternatives have been identified.

The other two relevant options — tradeable CfDs and direct investment support — are for now less viable due to their risks and limitations. Tradeable CfDs require large changes in the support system, causing continuity risks when implemented on the short term. Direct investment support

[105] Yet, a 2-way CfD scores better than a 1-way CfD on this point.

does not allow for a suitable limit on excess profits. While implementable on the long term, given the policy objectives both still have large disadvantages. In addition, tradeable CfDs are administratively complex, and may hinder the development of private long-term contracts. Another disadvantage of direct investment support is that implementing any clawback mechanism is complex and difficult. Overall, the risk of excess profits is higher for investment support than for operational support, since it requires to make an upfront estimation of costs and revenues, which cannot be corrected in later years (in contrast to operational support).

Different (combinations of) instruments could be considered beyond 2025, or positive elements of these instruments can be integrated (gradually) in existing policies. On the positive side, both tradeable CfDs and direct investment support allow generators to be fully exposed to market signals, and hence score well on the coherence with long term energy system objectives. In addition, direct investment support *can* be considered for costs related to elements that do not affect the operations of a generator, such as additional costs for nature. We did not assess this in detail, but we did not identify red flags from an operational perspective for such a combined approach.

2: Possible design choices for a 2-way CfD

The main design choices of the 2-way CfD require further research and are key for the efficiency, effectiveness and the overall attractiveness for investors.

Overall, the 2-way CfD is identified as the best suited option on the short term. However, its success is highly dependent on design choices. Further research is required on these design choices. Assessing these design choices was no objective of this study, but we offer first considerations for the possible further design. Important design choices include: setting an auction format that fosters competition, choosing a single strike price or a range and designing good payment calculation methods.

Besides the possibility to limit excess profits, a 2-way CfD does not significantly differ from the existing 1-way CfD: the SDE++. Successful design elements of the SDE++ can be retained. At first sight, we found no appealing arguments to change e.g. the auction format, the funding of the scheme via the general budget, the current role of PBL and strike price calculations, or the current solar and wind categories (from a technical perspective based in the differences between 1-way and 2-way CfDs).

To avoid negative issues observed in 2-way CfD schemes abroad, it is very important to ensure that generators are exposed to the right incentives. Most importantly, to maximise production value, rather than production. While our analysis is not sufficient to give concrete recommendations here, in general this implies that generators must be maximally exposed to short-term market signals. This can be achieved by selecting a reference price and payment calculation method that supports an efficient operation of the plant. Similar to the tradeable CfD option, one could even calculate payments based on a reference plant (including volume) in a 2-way CfD scheme. However, there are challenges that require further investigation.

Some other design elements could be changed compared to the SDE++. Further analysis is also required here. For example, inflation indexation could be considered, and additional criteria could be used in the tendering process (to address secondary or subobjectives). As a 2-way CfD differs from the 1-way CfD SDE++, a separate budget for solar and/or onshore wind is inevitable, which presents new, important design and budget allocation choices to be addressed by EZK. Also, to develop private long-term markets, a production limit (e.g., 80% of a plant's production, or leave freedom to developer to choose) could be set for support, ensuring that a part of the production is not covered by the CfD.

3: The role of system costs in support schemes

The support scheme could better support the reduction of energy system costs if generators are incentivised to maximise market value instead of production. While certain measures can be integrated in a support scheme, the most effective solutions are likely outside the scheme.

Energy system costs are substantial, and they will expand heavily in the coming decade. These costs are not explicitly taken into account in the SDE++. Considering system costs is a crucial element in energy policy and becomes more relevant as these costs increase; the entire energy system will be transformed. We distinguish two types of energy system costs: 1) system costs due to insufficient coupling between supply and demand and 2) grid expansion costs and congestion (including storage).

To better couple supply and demand and facilitate an efficient transition to a zero-carbon energy system, full exposure to short-term market price signals is key: electricity generators should optimise market revenues, not production. Minimising overall system costs are an important subobjective, which can to a certain extent be addressed within the support scheme. The SDE++ still distorts price signals. Options like investment support and tradeable CfDs ensure full exposure to market signals, while the 2-way CfD could be designed to limit subsidy maximisation instead of market revenue (more information in block 4 of these conclusions). This would lead generators to optimise their technology, siting, and operational choices. Incentivising market revenues contributes to relevant system investments, such as storage and demand flexibility. Further support of these system investments could be tackled inside or outside the scheme, depending on the costs and benefits; other instruments may prove more efficient.

An energy system perspective should be used to make fundamental choices in energy policy; all major system costs should be considered. To some extent, these could be integrated in the support scheme. Inefficient grid capacity extensions and grid congestion are major barriers to decarbonisation on the short and medium term. Despite, the SDE++ and the Dutch electricity market design do not implicitly take grid costs into account. While some measures were added to the SDE++ to mitigate the impact on grid capacity (50% max capacity connection and upfront indication of grid capacity for solar PV), this is not done on a fundamental basis. Considering system costs are crucial for a cost-efficient and fast rollout of renewables. However, it is not evident that the solutions lie within the support scheme. Other policies (spatial planning, network tariffs, TSO/DSO regulations) and governance levels (provincial/municipal) could be more important. Theoretically, all considered policy options can integrate system costs to different degrees, among others via setting criteria. Options that allow for more steering (e.g., a 2-way CfD) are better placed to solve urgent energy system issues, such as planning efficient grid capacity extensions. One of the advantages of addressing issues outside the support scheme would be that all new projects can be targeted, instead of only the (possibly decreasing) share of government-supported projects.

4: The role of secondary objectives in support schemes

Policy objectives related to e.g., nature, circularity, spatial planning and local participation can be addressed in all considered options, but to different extents. More market-based options fit less well, as additional costs directly affect project development efforts. It may still be better to address certain non-energy related policy objectives outside a future support scheme.

Solar PV and onshore wind projects have an impact on nature, spatial planning, and materials use. With the number of projects increasing, these total impacts increase as well. Despite, the negative external effects of renewable energy are still magnitudes lower than those of fossil energy. Addressing these impacts can hence be a secondary objective to be pursued by the support scheme. In this analysis we have analysed if the support schemes potentially can take these secondary objectives into account.

All options can take secondary objectives into account, but the extent to which options allow to steer *within* an instrument differs. Via minimum requirements, all options can steer on secondary objectives. Objectives with generic characteristics (e.g., circular PV panels) can be better addressed in support schemes than objectives requiring a tailored approach (e.g., location specific nature measures for solar PV).

In most cases, steering on secondary objectives leads to additional costs and hence presents a trade-off (climate goals vs. other goals). The more market-based a scheme is, the less room there is to steer on subobjectives *within this scheme*. Hence, a 2-way CfD offers more room to steer than a PPA fund. In the case of PPAs (and other more market-based instruments), the additional costs that may be caused by pursuing more objectives are incurred by the project developer. As a result, investments may decrease as market actors steer on lowest costs. In market-based schemes where additional costs cannot be covered by subsidies, steering on secondary objectives not only leads to increased costs, but also lowers the effectiveness and efficiency of reaching the primary objective. This should not imply that more market-based instruments are necessarily inferior to less market-based instruments; however, different policies could pursue additional objectives in more effectively and efficiently.

While all options can take secondary objectives into account (to different extents), this is not necessarily desirable: there is no one size fits all solution in which all policy objectives are pursued in a single instrument. In Chapter 2, we argued why we focus on climate goals in assessing the effectiveness of the support instrument. Renewable energy projects also involve externalities. As the energy transition progresses and as renewable energy projects become more visible and numerous, the level of externalities increases (while negative externalities of renewables are much lower than those of fossil fuels). As a result, the prioritisation of different policy objectives may change. In our view, an externality should be addressed if sufficiently sizeable and if the benefit of addressing outweighs the costs. To answer this question, one should assess different options to address externalities, inside and outside a future policy instrument. Addressing externalities inside the policy instrument generally compromises on the effectiveness. To our understanding, the fundamental question —how to best steer on these policy objectives— has never been studied. Whether or not steering on secondary objectives within the instrument is more effective than outside has also not been assessed in this research.

Annex I – additional information on instruments abroad

A. United Kingdom: Contract for Difference scheme (CfD)

Key characteristics

Key characteristics of the UK CfD scheme are (in addition to those discussed in section 3.3.1):

1. It is funded via a levy on the energy bill;
2. The payments are settled monthly and are calculated on the difference between the strike price and the reference price (tracking wholesale power prices) for each hour of the month;
3. There is no limit to the amount of electricity each unit can produce during the contract.
4. Contracts are awarded:
    - A. Via price-only auctions;
    - B. On a sealed-bid, pay-as-clear basis. Clearing (strike) price is set according to the highest offer to receive a contract in the auction round before the budget is used up;
    - C. At a strike price that is indexed to inflation (Producer Price Index or PPI).
    - D. Differentiates baseload and intermittent generators, with the main difference being the calculation of the reference price.[106]
5. Auctions are technology-neutral, but divided in two pots:
    - A. *Established technologies*: onshore Wind (>5 MW), solar PV (>5 MW), energy from waste with CHP, hydro (>5 MW and <50 MW), and landfill gas and sewage gas.
    - B. *Less established technologies*: offshore wind, wave, tidal stream, advanced conversion technologies, anaerobic digestion, dedicated biomass with combined heat and power and geothermal.
6. The government sets an administrative strike price, which is the maximum price that it is ready to pay for each technology.
7. During negative price periods, the low carbon contracts company (LCCC) does not pay generators. For CfDs awarded in the first three auction rounds, Non-Payment Periods are calculated when the reference price is negative for six consecutive hours. From Allocation Round (AR) 4, the definition reduces to any single hour with a negative reference price.
8. The scheme includes qualification criteria and penalties. Each project must:
    - A. Meet spatial planning requirements, demonstrated by having all required permits;
    - B. Have a connection agreement with the TSO/DSO;
    - C. Not receive other public funds;
    - D. Submit a 'supply chain plan' which details how the project will promote competition, innovation and skills in the supply chain;

   Developers will be penalised if:
    - A. They do not sign the CfD that they are offered after winning the auction;
    - B. They fail to deliver the project or fail to deliver it on time.

   However, the scheme allows developers a degree of flexibility concerning the date on which they start generating and receive CfD payments, to provide confidence to investors that the contract is valid in case of unexpected construction or generation delays.

[106] For Baseload CfDs, the Reference Price is set six-monthly: it is the market price for the forward six-monthly season baseload contract, as quoted during the sixth month prior to delivery. For example, the Reference price for all delivery periods from 1st April to 30th September 2023 inclusive is the forward market price for Summer 23 baseload, averaged over all working days between 1st October 2022 and 31st March 2022. For Intermittent CfDs, the Reference Price is set hourly: it is the weighted average of the settlement prices for the two day-ahead auctions, run by the N2EX and EPEX power exchanges, for the relevant hour (quoted from The pros and cons of contracts for difference | Squeaky Clean Energy)

Figure 0-1 Strike prices and capacity awarded to onshore wind and solar PV contracts above 5 MW capacity (2023 prices)

	AR1 (2015)[107]		AR4 (2022)[108]		AR5 (2023)[109]	
	Price (£)	Capacity (MW)	Price (£)	Capacity (MW)	Price (£)	Capacity (MW)
Onshore wind	119-125	1911	63	888	79	1481
Solar PV	76-119	72	70	2209	71	1928

**AR = Allocation Round*

Main issues

Issues and risks for generators:

1. Intermittent generators forecast their output for each hour at the day-ahead stage and aim to sell that amount of energy into the day-ahead auctions. If they have forecasted output correctly (and sold in each of the two auctions – N2EX and EPEX auctions are at different times – in the correct proportion) they will collect from the sale of their power an average price equal to the Reference Price for that hour: Physical sale revenue = RP x Output. Adding the CfD payment/receipt makes the overall net revenue equal to the generator's output times the Adjusted Strike Price: (RP x Output) + (ASP – RP) x Output = ASP x Output. Thus, generators may sometimes end up selling for a price lower than the RP, and thus earn less than the amount expected by the CfD.[110]
2. Generators do not receive a price during negative price periods, which could be an issue particularly for solar and wind as more of these capacities comes online.
3. Volume risks: generators' revenues will vary with wind or sun availability, which means their revenues may vary year by year. When selling to the market, the reduced wind or sun availability will affect the price (higher with low generation, lower with high generation), but this effect disappears with a CfD. It is unclear whether this is a significant issue, given that over the life of the contract, annual revenues would tend towards the average.

Issues and risks for consumers:

1. There is a "**Produce-and-forget**" incentive:[111] generators have no benefit of producing electricity when its needed most, or in reducing their output at certain hours in response to market signals (unless price is negative). In general, the UK CfD incentivises generators to maximise the *amount* of their output, rather than attempting to maximise the *value* of their output. For example, west- or east-facing solar panels might yield less total output than south-facing panels but produces more when most solar PV will not be generating, and market prices are higher (evening and morning hours). There is also no incentive to install onsite storage, to benefit from higher market prices or to reduce congestion at certain time. The costs of these misaligned incentives are then passed on to the consumers via higher market prices and/or congestion management costs.
2. The CfD results in consumers taking on **market capture (cannibalisation) risk**: Capture (cannibalisation) risk: when many new generators of the same type come online, especially if intermittent, they may generate all at the same time, depressing the price, and capturing revenues at depressed prices. This risk is also weather-related.

[107] Department of Energy and Climate Change (2015), Contracts for Difference (CFD) Allocation Round One Outcome
[108] Department of Energy and Climate Change (2022), Contracts for Difference Allocation Round 4 results
[109] Department of Energy and Climate Change (2023), Contracts for Difference Allocation Round 5 results
[110] The pros and cons of contracts for difference | Squeaky Clean Energy
[111] EconStor: Financial Wind CfDs

3. The CfD mechanism distorts short-term intraday and balancing markets.[112] The CfD top-up or payback is calculated on the per-hour day-ahead price. Once the auction price is known, this will incentivise the generator to make suboptimal choices, such as curtailing production when it would make sense to generate (if intraday or imbalance price is below the difference between the strike price and the day-ahead price, when market price > strike price), or increasing production beyond marginal cost (when market price < strike price). It is however difficult to estimate to what extent generators engage in these strategic behaviours in reality. Because of flexibility associated with the start of the CfD contract, developers can exploit this delay to benefit from high market prices.

Issues and risks for suppliers:

1. Suppliers hedge some of the risks described above to consumers via their offered tariffs, which means that they may have to shoulder these risks themselves if their hedging strategy is not effective (i.e., if they have not increased their tariffs sufficiently to cover the amount of fees that are due to the LCCC).
2. Suppliers are still left with what is called "**quanto risk**", deriving from the interaction between price and weather (volume generated). This and the capture risk become bigger as the share of intermittent renewable increases.

Evolution of the scheme

From the next iteration (AR5), the government has introduced some key changes to the rules:

- Offshore wind is considered an established technology and will bid in the same auction as Onshore Wind, Solar Photovoltaic, Energy from Waste with CHP, Hydro, Landfill Gas and Sewage Gas.
- The Non-Delivery Disincentive (NDD) has been strengthened: sites that do not meet delivery commitments are excluded from the next two applicable allocation rounds (instead of from the next applicable allocation round only). This is to ensure that the NDD remains an effective deterrent against speculative bids or non-delivery in the context of annual allocation rounds.
- The loophole that allowed generators to delay the start of the CfD for commercial reasons (i.e., start the CfD only when market prices are low) was closed.

Further changes are being considered for AR6, such as:

- Options to include offshore wind farms connected to an interconnector.
- Repowered projects.

According to a recent evaluation,[113] the UK's CfD scheme has been a success compared to its predecessor (the Renewable Obligation scheme). It has given investors confidence to invest in UK renewable energy projects and attracted greater investment at a lower cost of capital and from a wider pool of sources.

According to the evaluation, developers and investors agreed that "*the CfD's fifteen-year price stabilisation contract reduced risks for investors by reducing exposure to wholesale price volatility, which then lowered hurdle rates for developers. This was reported to have increased access to the provision of finance from a wider pool of investors, resulting in competition among lenders and more attractive interest rates being offered. CfDs play an important role in enabling finance deals that would not happen otherwise.*"

[112] EconStor: Financial Wind CfDs
[113] Evaluation of the Contracts for Difference scheme - GOV.UK (www.gov.uk)

B. France: PPA guarantee fund

The French PPA guarantee fund scheme has the following characteristics:

1. The guarantee fund is very recent – it was announced in November 2022, with the first contracts secured in 2023.[114]
2. The guarantee is applicable only to fixed-price fixed-volume PPAs;
3. The guarantee is a contract between the generators, the offtaker, and BPIFrance;
4. The guarantee is for a physical PPA, i.e., the buyer is also the offtaker of the electricity;
5. The guarantee is available only for greenfield projects, and cannot be cumulated with other existing subsidies or state support measures;
6. The guarantee is aimed at large projects, with a minimum offtake volume size of 10 GWh per year. This means that large electricity users (industry) are the most likely beneficiaries;
7. The guarantee covers 80% of the missed revenues;
8. The pricing is dependent on creditworthiness of the offtaker, and may vary over the years.

With a PPA contract and the guarantee fund in place, banks or other financial institutions will have greater confidence that these renewable energy projects are at a lower risk of default which results in a lower loan rate, leading to a reduction in project costs.

Main issues and risks

This measure relies on the demand from large energy users, for example, in energy intensive industries. This is likely to be insufficient to drive a substantial increase in the capacity of renewable energy; even if there was sufficient demand, the fund is expected to cover renewable energy installations with a total installed capacity of up to 500 megawatts, which is significantly short of the new renewable generation required for France. As it is currently implemented, it is likely that government backed CfDs will remain the preferred choice for generators, because the government is seen as a more reliable contract counterparty (making finding finance easier) and because of the difficulty in finding the offtakers.

[114] Bpifrance (2023), Bpifrance to provide a guarantee for the long-term supply of green electricity.

Annex II – List of interviewees

Organisation
De natuur- en milieufederaties
Energie Nederland
European Commission – DG Energy
California Public Utilities Commission
Government of Poland
Holland Solar
Independent
International Renewable Energy Agency (IRENA)
InterProvinciaal Overleg (IPO)
Nederlandse Vereniging Duurzame Energie (NVDE)
Nederlandse Wind Energie Associatie (NWEA)
Netbeheer Nederland
Planbureau voor de Leefomgeving
Powerlink Queensland
Rebel
Stedin
Wind Energy Systems Division, Technical University of Denmark
Vereniging Nederlandse Gemeenten (VNG)

Trinomics B.V.
Mauritsweg 44
3012 JV Rotterdam
The Netherlands

T +31 (0) 10 3414 592
www.trinomics.eu

KvK n°: 56028016
VAT n°: NL8519.48.662.B01