Cost-benefit analysis of alternative support schemes for renewable electricity in the Netherlands

J.C. Jansen
S.M. Lensink
Ö. Özdemir
J. van Stralen
A.J. van der Welle

ECN-E--11-002 March 2011

Acknowledgement
This report has been commissioned by the VME (Vereniging voor Marktwerking in Energie), now merged with EnergieNed into the vereniging Energie-Nederland (vE-N). The authors acknowledge the stimulating comments made by Mr André Jurjus, executive director of vE-N and Mrs Ineke van Ingen, project coordinator on the part of vE-N. Moreover, very helpful information was provided, among others on the Swedish certificate system, by Mr Klaus Hammes, Mr Roger Östberg and Mr Thomas Levander of the Swedish Energy Agency, Mr Torodd Jensen (NVE, Norway) and Mr Claes Hedenström (Vattenfall) at and following a meeting at the office of SEA, Stockholm, on 26 August, 2010. We also gratefully mention the help given by Mr Holger Gassner (RWE) and Mr Stefan Ulreich (E.ON) in providing additional information on the German support scheme. Mr Bert Daniëls (ECN) gave useful comments in his capacity of internal reviewer.

Full responsibility for any remaining errors contained in this report lies solely with the authors. The ECN number of the project resulting in this report is 5.0743. Contact person for this project at ECN is Mr Jaap Jansen (j.jansen@ecn.nl).

Abstract
The research project described in this report encompasses a quantitative assessment of the net social benefits of three alternative policy support systems to stimulate the Dutch uptake of power from renewable sources up to a level of 35% of gross domestic electric power consumption (RES-E) in 2020. The costs and benefits of each of the alternative policy support systems are compared on an incremental basis to the baseline scenario, which basically is an intensification of the existing feed-in premium (SDE) system up to a level yielding the 35% share in 2020 as well. In other words, this study seeks to identify which of the support systems considered, i.e. the baseline system and the three alternative support systems, is most cost-effective. The three alternative support systems are:
1. Introduction in the Netherlands of a German-like FIT system instead of the current SDE scheme to support renewable electricity as of 2014.
2. Introduction of a *national* demand-side Renewable Quota System (RQS) system for suppliers in the Netherlands in combination with the SDE as of 2014.
3. Introduction of a joint Swedish-Dutch hybrid RQS support system for suppliers as of 2014 whilst keeping the Dutch SDE and possible other supplementary support measures in the countries involved in place. Depending on the design of the joint RQS and supplementary support measures in the countries involved, part of the additional RES-E consumed in the Netherlands might be produced by qualifying Swedish RES-E generators.

Contents

List of tables

List of figures

Summary

Recommendations
We advise to consider the transition in Dutch support scheme from the current SDE support scheme to an integrated mix of the SDE scheme with a national certificates-endorsed, demand-side Renewable Quota System (RQS). The RQS component of this hybrid support scheme can best be aligned to the Swedish renewable support system. Should a positive decision be made, it is advised to start negotiations with Sweden (and Norway if the envisaged joint Swedish-Norwegian renewable support scheme materialises) to enter into expansion of RQS to the Netherlands. Realisation of Dutch participation in a well-designed joint hybrid RQS scheme would imply the highest socio-economic benefits to Dutch society. The Swedish scheme has proven to be effective and quite efficient in bringing about compliance with pre-set RES-E expansion targets. An important design consideration would seem to be alignment to the Swedish support scheme as much as possible and in the most appropriate way for the Dutch situation.

Main results
This report presents a quantitative and qualitative cost-benefit analysis of the net benefits for Dutch society of readjusting the current renewable electricity support system to either one of three distinct alternative support schemes. The current Dutch support system is a feed-in premium system, referred to by the Dutch acronym SDE. The three alternative support systems, shaping the corresponding *Alternative Scenarios* considered in this report are:

I. A feed-in tariff system analogous to the German EEG system **(FIT)**.
II. A renewable quota system (RQS) on top of, and well-integrated with, the current SDE system, implemented nationally only **(RQS-NL)**.
III. A renewable quota system on top of - and well-integrated with - the current SDE system, with the RQS being implemented jointly with Sweden **(RQS-SE)**.

Our analysis period stretches from 2013 through target year 2020 of Renewable Energy Directive 2009/28/CE (RED) and until 2035 to analyse projected trends and economic impacts over a more long-term period. In Table S.1, the net present value of the savings in comparison to the baseline scenario is calculated for the two periods indicated: 2013-2020 and 2013-2035 respectively. The share of renewable electricity accountable for compliance with the Renewable Energy Directive is 35% in the baseline and all alternatives. With the exception of Alternative III, all accountable renewable electricity is produced in the Netherlands.

Table S.1 *Net benefits from a Dutch socio-economic perspective of a shift in 2014 from the prevailing SDE support scheme to three alternative support schemes*

		Net present value in 2010 (€$_{2010}$ billion)					
Period			2013 - 2020			2013-2035	
Discount rate		0 %/a	2.5 %/a	5 %/a	0 %/a	2.5 %/a	5 %/a
Alt I (FIT)	Same RES-E mix evolution as in the baseline	0.2	0.2	0.2	0.9	0.7	0.5
Alt I (FIT)	Divergent RES-E mix evolution	0.0	0.0	0.0	-1.4	-0.8	-0.5
Alt II (RQS-NL)	Same RES-E mix evolution as in the baseline	1.2	1.0	0.8	0.9	0.9	0.8
Alt II (RQS-NL)	Divergent RES-E mix evolution	1.5	1.3	1.0	1.9	1.6	1.4
Alt III (RQS-SE)	Divergent RES-E mix evolution	2.9	2.4	2.0	9.0	6.6	4.9

In Table S.1, we have assumed that the alternative scenarios can be implemented in 2014. Table S.1 shows that the joint hybrid RQS with Sweden is the most attractive option. In case a joint Dutch-Swedish system would not be possible, a Dutch hybrid RQS would also generate positive, albeit lower, net result.

Design considerations for RQS scheme

Good system design is essential to realise the expected net benefits. The RQS supervisory authority and the central government should closely monitor the RQS certificate market and use a range of intervention instruments to foster the RQS certificate price fluctuating within a target bandwidth. Too low prices discourage investments in RES-E technologies solely supported by RQS certificate revenues, whilst too high prices that significantly exceed the projected cost gap of the lowest cost of large RES-E technology in need of support by the hybrid RQS may lead to unacceptable windfall profits. Instruments at the disposal of the authorities include:

- A broad diversity of RES-E technologies participating in the RQS system.
- System target setting.
- Integrating certificate market considerations in setting SDE subsidy base rates.
- Integrating certificate market considerations in setting technology-specific SDE budget ceilings.
- Allowing banking of RQS certificates.
- At least initially a minimum RQS certificate price could be guaranteed as was done when introducing the RQS certificate system in Sweden.
- The option of raising the quantity of generated RES-E electricity per RQS certificate issued to more than one MWh might be exercised under certain well-specified market conditions; only for certain biomass options for which capital investments account for a low share and recurrent costs among which notably fuel costs account for a high share in the total cost per unit of electricity.

Scope of assessment

Our quantitative analysis has focused on those effects that can be quantified with a fair amount of robustness. For example, in our quantitative analysis we have refrained from taking recourse to sweeping, speculative assumptions on the nature and volume of external effects of specific 'innovation pathways', the innovation dynamics of inter-technology competition, the strategic value of bottom-up harmonisation of national support schemes, etc. Some major limitations of our quantitative analysis are:

- We have only considered direct RES-E cost (savings) effects from a social perspective, resulting from a shift from the baseline to either one of the three alternative support schemes. The reason is that we do not have an economic input-output model at hand. It is unlikely that inclusion of indirect welfare effects would have materially altered our conclusions.
- We have not allowed for effects on network reinforcement and network operation costs, given the complexity to credibly do so.
- We have not internalised the negative external effects of the mandatory shift of a series of market risks from RES-E generators to other market players under the Alternative I scenario. A major exception is the extra cost of instantaneous balancing system power supply and demand under a feed-in tariff system with regard to wind power, which has been taken into account.

Assessment of Alternative I: German-like FIT

On the basis of the quantitative results and the complementary qualitative analysis of differential RES-E trends in Germany, the following conclusions can be drawn about a shift from the baseline scenario to a German-like FIT scenario:

- Especially in the longer term, it will have negative social welfare implications for the Netherlands.
- It will strategically set back the Netherlands in capitalising on opportunities for (bottom-up) harmonisation.

- It will increase the hurdles towards smooth integration of intermittent renewables and the introduction of effective smart grid concepts.

We refer to statements made by the German government, e.g. in the recent important *Energiekonzept* document, stressing the need for reform of the current EEG support system to improve market integrating of RES-E. Should the optional feed-in premium proposal - also referred to in the *Energiekonzept* - be adopted indeed, which appears to be a real possibility, then the German support system is due to evolve to a major extent towards the support system that is currently in place in the Netherlands.

Assessment of Alternative II: a national hybrid RQS

On the basis of the quantitative results and the complementary qualitative analysis, the following conclusions can be drawn about a shift from the baseline support scheme to a national hybrid support scheme:

- It will have - relatively modest - positive social welfare implications for the Netherlands.
- It might foster innovation towards cost reductions for some large-scale RES-E technologies.
- It will place the Netherlands in a good position to capitalise on opportunities for (bottom-up) harmonisation.

Assessment of Alternative III: a joint hybrid RQS support scheme with Sweden (RQS-SE)

Taking the baseline scenario as benchmark, our results indicate in a robust way with respect to choice of discount rate and projected RES-E mix trends, that Alternative III will enhance Dutch social welfare quite robustly and is from this perspective the most attractive alternative considered by far.

Our analysis of aggregate effects of the Alternative III scenario for Swedish society against a national RQS shaping the baseline scenario has not yielded conclusive results. More research on the Swedish perspective is needed involving relevant Swedish research institutes. On aggregate, Swedish renewable generators applying qualifying technologies for participation in the RQS are set to be clear winners and other Swedish generators clear losers. Less robust indications suggest that Swedish consumers may benefit.

Final observations

Changing the Dutch RES-E support scheme should not be undertaken just for the sake of complying with the commitment to the EU RES target for 2020. Market players should be offered a reliable long-term support framework. The long-term feature is part of the design of well-functioning RQS schemes. Changing a support scheme from a feed-in premium to a hybrid RQS scheme in cooperation with Sweden is a delicate process, in which the following challenges are likely to emerge:

- Supply-side market power within the RQS certificate market (and limitation of windfall profits).
- Exposure of large power consumers to foreign competition.
- Marketing green power products.
- Grid constraints in Sweden.

Another major issue is the streamlining of permitting procedures. Monitoring and, when needed, interventions by the central government are in order, should undue delays occur at lower government levels. This issue is not only key in achieving very ambitious RES-E sub-targets, but is also of key importance for a well-functioning national RQS certificate market.

1. Introduction

1.1 Report background

The Dutch government has committed to achieve the national 14% renewables target for the Netherlands in year 2020, mandated by EU Renewables Directive 2009/28/EC. Accordingly, 14% of Dutch final energy use is to originate from renewable energy sources. Given the difficulty in increasing the low renewables share in the Dutch consumption of transport fuels and in Dutch energy use for heating and cooling purposes, several scenario analyses have pointed at the need to source (at least) a 35% share in Dutch gross electricity consumption from power plants using renewable sources of energy. In turn, given the poor Dutch renewable energy resource base this warrants fast rising expenditures on SDE subsidies to lift the commercial production of renewable electricity to the volume required to achieve a 35% share of renewable electricity (RES-E) in 2020.

The envisaged rising SDE expenditures at the backdrop of a Dutch economy, severely affected by the impacts of the global financial crisis, raises the question as to whether the 35% RES-E share in Dutch electricity consumption can be achieved in an alternative more cost-effective way. If the answer is affirmative, this would help the Dutch economy: lower end-user electricity costs raise the competitive position of electricity-using companies and would increase the purchasing power of Dutch households.

The Vereniging voor Marktwerking in Energie (VME) has issued a position paper, entitled: 'DE MARKT VOOR DUURZAAMHEID - Visie van de Vereniging voor Marktwerking in Energie op de noodzakelijke verduurzaming (VME, 2009). This paper proposes the introduction of a Renewable Quota System (RQS) in the Netherlands. This standard would impose on retail suppliers[1] the requirement to source a certain minimum proportion of their deliveries with electricity that was produced from qualifying renewable energy sources (RES-E). This RQS is to be backed up by a system of tradable (renewable) electricity certificates. In this report such certificates are henceforth referred to as *RQS certificates*.

This report sets out to analyse the attractiveness of selected support systems for renewable electricity from the perspectives of Dutch society and key stakeholders. This is done in a quantitative way to the extent possible, i.e. in the form of a quantified cost-benefit analysis, complemented with a qualitative analysis of costs and benefits. Point of departure is that the 35% share in Dutch gross electricity consumption from power plants using renewable sources of energy will be reached for all the support scenarios considered. Hence, in each scenario the implementation intensity level of policy support towards deployment of renewable electricity is presumed to be precisely attuned to reaching the pre-set 35% target. Moreover, for all scenarios considered the evolution of the aggregate volume of RES-E consumption is presumed to be exactly the same. The choice for these points of departure means that with respect to the main benefit category for renewable electricity support systems, i.e. deployment of renewable electricity, the benefits will be equal in quantity in all the scenarios considered. Hence, the focus of this study is on the cost-effectiveness issue of the support schemes considered. In this approach the benefits of renewable electricity as such, e.g. the value of consequential CO_2 reductions, do not need to be monetised: given the aforementioned points of departure these are broadly the same for all alternative support schemes considered in this report.

[1] In principle, it can be decided to broaden the participatory basis of the RQS to selected final electricity users with still due regard for exposure to international competition, for example in the way as implemented in Sweden.

1.2 Objective and scope of the report

This report sets out to provide informed and robust insights enabling to answer the key research question: Which support system can achieve the pre-set target - 35% of Dutch electricity consumption in year 2020 from renewable sources - at the lowest net additional cost to Dutch society?

The baseline scenario for this study, against which alternative support schemes will be considered, is formed by the prevailing Dutch support scheme, i.e. the SDE scheme, which is basically a feed-in premium support scheme. It will be assumed that this scheme will be intensified in such a way that the 35% RES-E share by year 2020 will be achieved. For reasons of technical feasibility of all scenarios considered, this is slightly lower than the corresponding projection of the official baseline scenario for the overall Dutch energy system, *Referentieramingen 2010* (Daniëls *et al.*, 2010) and the draft proposal for the National Renewable Energy Action Plan that the Dutch government has submitted to the European Commission, i.e. 39%. For the alternative scenarios, this target is not realisable, because some initial slow-down of investments in Dutch renewable electricity projects needs to be anticipated, following public announcement of steps to revise the support scheme. Reaching a 35% share of renewable electricity in Dutch final power consumption remains quite an ambitious challenge anyway.

For the purposes and limitations of this report, the following alternative support systems have been selected for close consideration:

1. Introduction in the Netherlands of a German-like FIT system instead of the current SDE scheme to support renewable electricity as of 2014.

2. Introduction of a national demand-side RQS for suppliers in the Netherlands in combination with the SDE as of 2014.

3. Introduction of a joint Swedish - Dutch hybrid RQS on suppliers as of 2014 whilst keeping the Dutch SDE and possible other supplementary support measures in the countries involved in place.[2] The benefit-cost analysis will focus on the Dutch perspective but will also draw preliminary conclusions on the Swedish perspective. Depending on the design of the joint RQS and supplementary support measures in the countries involved, part of the RES-E consumed in the Netherlands might be produced by qualifying Swedish RES-E generators.

1.3 Report structure

Chapter 2 provides background information on the general methodological framework to be applied for the present study. Chapter 3 outlines the approach for the scenarios' construction and elaborates on the baseline scenario. Chapters 4 to 6 show the result of cost-befit analysis of a system change towards respectively the alternative support schemes: (I) a Feed-In Tariff scheme, (II) a national hybrid Renewable Quota System and (III) a joint hybrid Renewable Quota System support scheme with Sweden. Chapter 7 concludes this report with a summary of findings.

---

[2] The case study example of a Swedish - Dutch joint hybrid RQS scheme can be considered as a study of the *proof of concept* for such systems. Currently the governments of Sweden and Norway are negotiating a joint RQS scheme, envisaged to be launched on 1 January 2012. A Swedish-Norwegian-Dutch hybrid RQS scheme would be more attractive than a Swedish-Dutch one. The reason is that Norway has an even better renewable resource base for qualifying sources, e.g. better wind resources, than Sweden. On the supply side of the tri-partite RQS certificate market there would hence be more competition, resulting in lower RQS certificate prices for potential net importer, the Netherlands.

2. Methodological framework for assessment of effects

2.1 Introduction

In order to gain insight into the societal benefits and costs of different support schemes for the Netherlands, a quantitative analysis will be conducted, complemented with qualitative analysis. Before starting with the quantification, all relevant effects of these support schemes should be analysed qualitatively in detail, since it will be difficult to quantify if it is unclear how an effect is caused. This chapter describes the methodological framework for the assessment of effects of a support scheme. It starts with delineating the scope and some major limitations of the framework (Section 2.2). General considerations and assumptions underpinning the methodological framework are presented in Section 2.3.

2.2 Scope and limitations of the methodological framework

The cost-effectiveness analysis performed for this study considers the impact of alternative support schemes, departing from the baseline scenario with an intensified SDE support scheme. All support schemes considered, including the one encompassed by the baseline, are assumed to be deployed at such a scheme-specific intensity that they all lead to a share for renewables in total Dutch gross electricity consumption of 35% by 2020. This anticipated major RES-E (electricity from renewable sources) contribution should enable the Netherlands to meet its overall national target for 2020 as mandated by Renewables Directive 2009/28/EC. This directive requires at least 14% of Dutch final energy consumption to originate from renewable energy sources. The cost-benefit analysis of alternative support schemes assesses their anticipated welfare effects upon Dutch society, to the extent that these effects diverge from the baseline scenario. In other words, it analyses incremental effects, i.e. incremental with respect to the baseline scenario.

Overview of effects to be quantified
As a first step of the analysis, the effects of the alternatives are assessed with regard to several aspects. These aspects, which are elaborated in Chapter 3, are changes in:
- The production costs due to change in project characteristics (size, feedstock, location).
- The cost of capital due to change in project risk.
- The electricity system integration costs (balancing costs).
- The production mix induced by the alternative support scheme.

Next, the effects for Dutch society are aggregated in (Chapters 4 to 6):
- Changes in the differential costs of RES-E in final Dutch electricity consumption.
- Changes in 'deadweight' regulatory costs for public and private stakeholders.

Also the distributional effects for major electricity system stakeholders are considered, resulting from, among other factors:
- Changes in base load electricity price.
- Where applicable, changes in RQS certificate prices.

Finally, the aggregate costs and benefits for the alternatives considered are summarised into alternative-specific net present values of aggregate projected annual costs and benefits cash flows.

Impact on electricity networks
Impacts of alternative support systems on electricity networks are extremely complicated to stylise in quantitative models in an adequate way. We will refrain from analysing incremental network effects in a quantitative fashion. We will limit ourselves to set out anticipated network

effects in a broad qualitative way. An exception is made for the cost of power system balancing for which differential impacts will be quantified to some extent.

Indirect effects
Our focus is on the direct welfare effects of a change in support scheme. However, secondary consumption and other indirect effects also occur. For example, primary revenue/cost impulses reverberate through the economy by effects on consumption by workers directly employed by RES-E installations and by power consumers whose electricity bills might be affected by the change in support scheme. Also macroeconomic (income and employment) effects may be generated through forward- and backward industrial linkages. Moreover, different support schemes may have divergent impacts on innovation. This study is restricted to quantifying the direct welfare effects only. Some indirect effects will be analysed in this report in a qualitative way.

The scope for a joint support scheme (Alternative III)
Currently, negotiations between Sweden and Norway to expand the Swedish certificates-backed RQS support scheme into a Norwegian-Swedish support scheme by early 2012 have reached an advanced stage. Yet agreement still needs to be reached on issues such as an acceptable sharing of (additional renewable generation) costs and (additional income and employment) benefits as well as how to achieve reinforcement of interconnections between Norway and Sweden to evacuate intermittent generation. According to unofficial information, the Swedish support scheme is also monitored with a view to possible collaboration elsewhere in Europe, e.g. in Flanders and Italy. In fact, just before the first bid to establish a joint Norwegian-Swedish support scheme floundered in 2006 on disagreement about targets, several other countries had shown interest in considering the option to link up, including Finland, Denmark and Poland. Recently, Finland embarked upon a feed-in tariff scheme without commitment to this scheme for the long term.

For the purposes of this study, Alternative III will only consider the case of a common support scheme between the Netherlands and Sweden as a *proof of concept*. Should the economics of a common support scheme between the Netherlands and Sweden prove positive, then expansion of such a scheme will only further enhance the overall net welfare benefits for the region covered by the common support scheme.

2.3 General considerations and assumptions

For reasons of comparison each alternative support scheme is presumed to be implemented at the start of 2014. Prior to a change in support scheme, investments have to be made in preparation. These projected investment costs are shown in aggregated form as a negative cash flow in pre-introduction year 2013. Therefore, we conducted a comparative study of annual net benefit cash flows as from year 2013. The financial close of many existing support-eligible RES-E installations and the ones that will be commissioned in the period 2013- 2020 implies contractual support commitments well after 2020 up to 2035. Moreover, structural trends regarding (positive or negative) net benefits of a change in RES-E support scheme in 2014 may well become much more robust after 2020. Therefore, the differential cash flow analysis - comparing the cash flows of each of the three alternatives with the corresponding ones of the baseline support scheme - will cover the period 2013 - 2035 with a focus on the period 2013-2020.

Currently much uncertainty exists about RES-E policies after year 2020. Within the framework of this project we have opted for a conservative and simple set of assumptions for the period 2021-2035, i.e.:
- Annual electricity demand after 2020 will stabilise at the level of 2020.
- Annual RES-E consumption volumes will stabilise at the level of 2020.
- Shares and mix of RES-E technologies remain broadly at the level of year 2020.
- Technological learning trends assumed for the period 2010-2020 will be sustained.

- Assumptions on fuel prices and CO_2 prices are taken from (Daniëls and Kruitwagen, 2010).

These assumptions allow on the one hand to gain a better insight into the nature of medium-term trends. On the other, they do not favour technology-neutral support systems (notably certificates-based RQS) as compared to technology-specific support schemes (notably Feed-In Tariff or Feed-In Premium systems). In fact, the contrary might be the case, as after 2020 further efficiency improvement in the choice of RES-E technology is not allowed.

Future annual differential cash flows have to be properly discounted to present values to enable aggregation of cash flows of different years. The most recent Dutch document on this issue for public sector investments was published in January 2007 (Werkgroep Actualisatie Discontogroep, 2007). It recommended a rate of 2.5% per year, to be raised for macroeconomic risks and, if possible, non-systemic project risks. The working group conjectures that for investments targeted at irreversible fundamental problems such as climate change, a lower discount rate might be applied without further elaboration. Meanwhile, the real interest rate on the Dutch capital market has come down markedly with the nominal interest rate on 10-year Dutch government bonds evolving from 3.8% per year ultimo 2006 to 3.2% per year at present, whereas after the financial crisis dip general price inflation is picking up again to a level on the order of 1.6 % per year (situation as per January 2011). Furthermore, apart from climate change considerations, renewable energy stimulation seeks to address the fundamental problem of potential threats to long-term energy services security (Jansen and Seebregts, 2009). Energy from renewable sources tends to mitigate price volatility of fossil fuels and the consequential adverse impact of price hikes of fossil fuels on macroeconomic business cycles. For these reasons we have opted to apply the relatively moderate real discount rate of 2.5% per year, whilst also showing results when applying a real discount rate of 0% and 5% respectively. The latter allows to gauge the sensitivity of the results for the choice of discount rate.

Many Cost-Benefit Analysis studies on the fostering of renewable or low-carbon energy attempt to grapple with the valuation problem of avoided GHG emissions (e.g., Koopmans *et al.,* 2010; Breitschopf *et al.*, 2010a and 2010b).[3] Such valuations are highly disputed. This study seeks to avoid these pitfalls by applying a differential cash flow analysis: the incremental (positive and/or negative) net benefits of each of the three alternatives with respect to the baseline scenario are considered. To the extent that emissions are avoided at all against the backdrop of a functioning EU carbon emissions limitation policy, all scenarios considered are to lead to broadly the same GHG emissions avoided. Therefore, we disregard impacts on GHG emissions. The same reasoning goes for local/regional pollutant emissions.

The single most important argument to conduct specific public renewables market stimulation measures and policies is the potential dynamic efficiency of currently commercially immature but promising renewable technologies. Dynamic efficiency benefits materialise through introduction and widespread adoption of cost-reducing innovations.[4] Market stimulation policies seek to accelerate the transition towards commercial competitiveness of the 'promising' technologies concerned. All our scenarios' policy intensification efforts are set to yield the same RES-E level, with certain differences in the RES-E portfolio distribution. Given the innate difficulty in predicting 'the winners', we do not pretend to have foresight capability in this respect and refrain from taking differential dynamic efficiency benefits between the alternative stimulation scenarios into consideration.

To conclude, we repeat the most important limitations that our quantitative analysis disregards the impacts on electricity network reinforcement costs and indirect effects on economic welfare.

[3] See also Appendix B.

[4] We note that predicting innovations and their cost impact is an art rather than science. On the other hand, well-designed innovation policies can positively impact on the germination of innovations and their subsequent adoption.

3. Approach for design of scenarios with focus on the baseline

3.1 Introduction

The quantitative analysis of the costs and benefits of different support schemes for the Netherlands takes the form of a differential analysis. In the differential analysis, the support schemes are compared to a baseline scenario. This chapter starts in Section 3.2 with a description of the baseline scenario and the description of three alternative systems. The approach to quantify the baseline scenario is explained in Section 3.3. Section 3.4 discusses assumptions made about cost developments for renewable technologies in the various alternatives. The quantification of balancing costs for the electricity system under the distinct support scenarios is addressed in Section 3.5. The chapter ends with an overview of projected RES-E trends under the baseline scenario (Section 3.6), as a benchmark for projected divergent developments in the alternative support scenarios to be discussed in the ensuing three chapters.

3.2 Description of systems

3.2.1 Baseline scenario: the prevailing SDE support scheme

Mid-2003 a feed-in premium system was introduced in the Netherlands as the main support mechanism of renewable electricity; the so-called MEP system. Subsequently, after a void interim period, the MEP system was replaced by the SDE system as per 1 April 2008. Main reforms with the introduction of the SDE system are: (i) the introduction of an ex post power price indexation adjustment to reduce windfall profits and (ii) the change of the Dutch support system from an open-ended to closed-ended system to contain total expenditure on the support system.

The *S*timuleringsregeling *D*uurzame *E*nergie (SDE) is the Dutch government's main subsidy instrument in support of the deployment of renewable energy in the Netherlands. The production of both renewable electricity and green gas are supported under the SDE scheme. Similar to the MEP system it replaces, SDE is a feed-in premium system. The production subsidies (premiums) are technology-specific for renewable energy technologies, qualifying for SDE support in accordance with SDE regulations set by the Dutch government. Below, the various elements which define the SDE are detailed[5].

For new renewable energy installations of a certain SDE-eligible category, the cost per unit of energy output (COE) over a certain operating period are projected each year on behalf of the Dutch government in consultation with stakeholders. For biomass categories this period is 12 years, whereas for other SDE subsidy categories this period is 15 years. The anticipated and approved COE are called subsidy base rates. For a certain SDE-eligible installation, the subsidy base rate is fixed over the whole subsidy contract period, i.e. 15 years for most installations. These base rates are point of departure for determining the production subsidy (premium) the operators of qualifying installations are entitled to. In projecting the subsidy base rates, a standard return on capital is presumed with a nominal weighted average cost of capital (WACC) of 6-8% per year[6], including a return on equity of 15% per year.[7]

---

5 Since the scope of this study is limited to support mechanisms for RES-E technologies, the description is limited to RES-E technologies but it is equally valid for RES-G technologies supported through the SDE.

6 The projected return on capital is technology-specific.

7 It is noted that most qualifying SDE categories concern high capital, low expense generation technologies. For these categories, granted a fairly stable rate of general price inflation the COE for an upcoming vintage of generation installations can be anticipated with a fairly narrow confidence interval. Major exceptions are several biomass-based technologies, especially biomass co-firing options.

The SDE premium for an installation of a certain SDE category commissioned in a certain calendar has to cover the so-called 'financial gap'. The applicable SDE premium is presumed to be the cost gap that needs to be bridged to render the investment in a SDE-eligible RES-E generation plant financially viable without triggering supra-normal rates of return. In principle, the SDE premium for a certain SDE-eligible installation of a certain vintage year is determined by the difference between its anticipated RES-E generation cost and the realised average electricity price over successive calendar years of the contracted subsidy period. The subsidy rate is capped in years with very low average electricity prices by the set electricity price floor. This is the lowest allowable electricity price to be used for determining the SDE premium.[8] At the time when the subsidy base rate is determined (prior to the calendar year of commissioning of a RES-E plant), an official long-term projection of the day-ahead base load electricity price on the Dutch APX power market platform is made. At the same time, this sets the applicable electricity floor price over the whole SDE subsidy contract period, i.e. at a level equal to two thirds of the official long-term electricity price projections.

The general formula for determining the SDE premium applicable for the past calendar year for a RES-E plant of certain SDE category that was commissioned in a certain vintage year, expressed in €ct/kWh, can be denoted as follows:

$$s = b - \left(\prod_i a_i \right) \cdot \max\left(p_{el}^{*}, p_{el}^{floor} \right) \tag{3.1}$$

where:

s	= the applicable premium rate, i.e. SDE production subsidy rate
b	= the applicable subsidy base rate, depending on SDE category and plant vintage year
p^*_{el}	= the realised average electricity price in the past calendar year
p^{floor}_{el}	= the electricity price floor, set for the past calendar year
a_i	= the adjustment rate for adjustment component i (strictly positive)

The subsidy base rate includes inter alia cost components for:

- Insurance costs: to provide some hedge against the risk for the RES-E operator that the electricity price drops through the set electricity price floor.
- Transaction costs: anticipated transaction costs to sell electricity (especially for SDE categories with many small-scale RES-E operators).

Without going into further details, adjustment components include the ones for:

- System imbalance charges: applicable for wind power, and solar PV.
- Profile costs: applicable to intermittent sources assuming a non-negligible share in the electricity fuel mix (relates to downward effect on power spot prices at times that high volumes of intermittent RES-E are fed into the electricity system).

Qualified RES-E generators receive advanced payments of the SDE premium in monthly instalments based on 80% of the subsidy rate that was projected in the month November, prior to the current operating year. In April of next year, the *ex post* subsidy rate is determined and the final settlement payment is made to the operator.

The electricity price floor implies a non-negligible risk to the investor and his financiers. If the electricity price is to drop below the set electricity price floor, the SDE subsidy rate will not suffice to provide full coverage of the 'financial gap' that needs to be bridged to render the RES-E power plants concerned financially viable. In practice, the adjustment rate for insurance against this risk does not give complete solace. For example, in 2009 for a number of SDE subsidy categories the electricity price skidded through the set electricity price floor. The price floor re-

[8] The Dutch government has introduced such a subsidy cap in order to limit the total allocations, required for covering the SDE subsidy contingencies over the whole subsidy contract period of SDE-eligible RES-E plants.

lated risk prompts more caution on the part of RES-E project developers and their financiers to invest and provide financing respectively. In turn, this translates into a higher required rate of return on investment and lower debt-equity ratios at financial closure of RES-E investment projects. This effect is exacerbated by the current economic recession.

In Figure 3.1 the effect of variation of the realised electricity price on the SDE subsidy rate is illustrated. For a subsidy base rate of 85 €/MWh and an average electricity price of close to 60 €/MWh, the subsidy rate over a 15 year subsidy period is given. In years 7 through 11 the electricity price drops below the price floor: during this period the subsidy rate is limited to the difference between the rate base and the price floor. In the years 13 through 15 the electricity price lies above the base tariff. During these years the RES-E plant operator's income will be larger than anticipated by the SDE-subsidy providing agency. Evidently, prudent project developers and their financiers attribute higher weight to the downside risk set by the electricity price floor in comparison to the upside of surging electricity prices.

Every year, the Dutch minister of Economic Affairs announces the funds available per SDE eligible support category. In addition, it is announced whether subsidy is assigned to projects on the basis of first come first serve or through a tender.

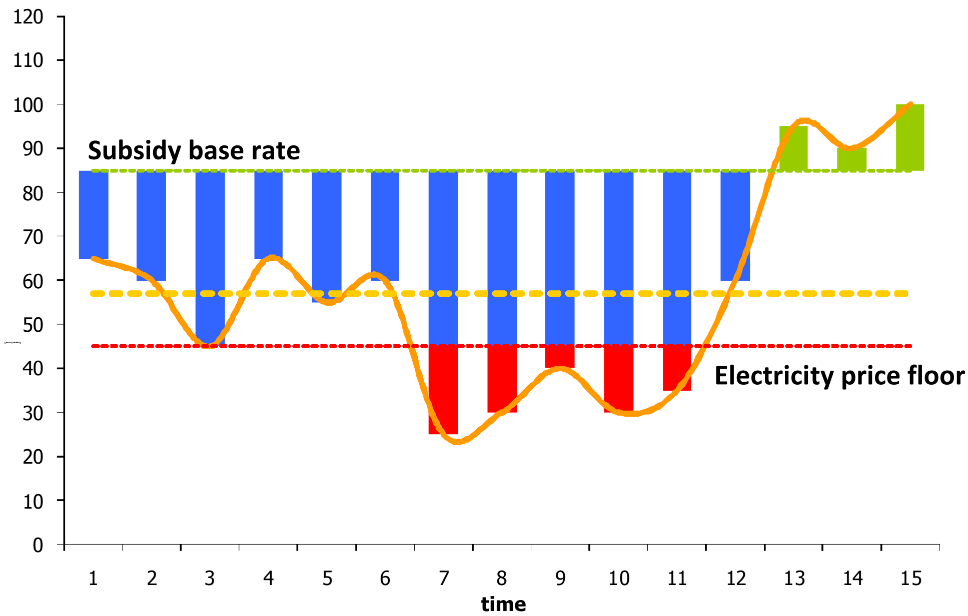

Figure 3.1 *Variation of the subsidy rate (blue bars) with the electricity price (orange line). The red bars indicate the situation in which the subsidy rate does not suffice to cover the RES-E production costs, the green bars indicate extra income on account of the electricity price exceeding the rate base. (Adapted from van Tilburg et al, 2008)*

3.2.2 Alternative I: introduction of a feed-in scheme[9]

The first alternative support scheme regards the introduction of a feed-in tariff (FIT) early 2014. The German FIT system boasts a lot of support. Many Dutch RES-E project developers, NGOs and politicians, attaching high priority to a fast transition towards a sustainable energy system recommend adoption in the Netherlands of the German FIT support system. Alternative I is designed to include the most important aspects of the German FIT system, notably a system that above all wants to reduce investor risks. Therefore, this report assumes a FIT system to be an open-ended system. It includes aspects that, to the opinion of the authors, are inherent to FIT systems: priority access to the public grid for transport of renewable electricity and balancing of

[9] See Sub-section 4.2.1 and Appendix B for further information on the EEG.

renewable electricity as responsibility for specified other stakeholders instead of renewable electricity generators themselves. It does not include more generic policy choices like the bearing of offshore connection costs by the TSO, the multiple bonuses with the EEG and the diversified, location specific support for onshore wind (so-called reference yield methodology).

In 1991 the German feed-in tariff system was introduced by adoption of the *Erneurbare-Energien-Gesetz* (EEG: German feed-in law). The EEG requires an immediate commercial transfer of qualified renewable electricity from EEG eligible renewable generators to system operators. The operators have to pay the generators preferential prices, mandated by regulations on account of the EEG. The TSO is responsible for sale of the electricity from these generators on the spot market and bears the balancing risk related to deviations of actual injections to ex ante notified power injections.

Eligible renewable electricity generating plants are granted a set technology-specific fixed preferential price concession for generally a period of 20 years. These concessions are granted on an open-ended basis, also for technologies with currently still high additional costs (relative to power from conventional sources), such as PV, certain biomass-based generation technologies and offshore wind. The price fixing for wind power plants during the concession period is more complex as it is a function of the actual yields compared to certain reference yields. Furthermore, each year the fixed preferential tariffs for *new* qualifying renewable electricity plants are typically adjusted in a downward direction, i.e. step-wise downward tariff digressions in line with the projected technology specific generation costs.[10] Every four years, the tariffs and future digressions are revised, which can result in a downward but also in an upwards correction.

The open-ended character of the EEG stands in stark contrast with the Dutch SDE support mechanism. A prominent feature of the latter mechanism is the application of annual budget ceilings per SDE category, which are typically more stringent for the technology categories with a high cost gap such as PV and offshore wind.

A second major distinction is the absence of balancing responsibility on the part EEG-eligible renewable generators. In contrast, SDE-eligible generators have to assume balancing responsibility or to pass on this responsibility at a negotiated cost to a third party willing to assume it. The absence of balancing responsibility for EEG beneficiaries basically means that in their power production/grid injection behaviour they will not take into account balancing cost implications for other stakeholders of the electricity grid. Nor are EEG-eligible generators exposed to commodity price risk as they are paid pre-set preferential tariffs. Again on this score, EEG-eligible generators will not take into account power market conditions to determine their production behaviour. Conversely, to some extent SDE-eligible generators do. This relates to:

- profile risk, i.e. the risk that they feed in on average at low price hours,
- merit order impact risk, resulting from the negative impact on power prices of large power injections from intermittent generators,
- commodity price risk: at low-demand hours electricity prices might reach negative levels such that SDE premiums may fail to compensate enough to achieve positive short-run marginal revenues per MWh of renewable electricity produced,
- risk of average yearly commodity prices falling through the electricity price floor of the SDE regulation.

3.2.3 Alternative II: introduction of a national demand-side RQS-SDE scheme

A hybrid certificate-based RQS has been selected as Alternative II for this study with the RQS target obligation on the demand side. Hence, power suppliers and, depending on system design details certain other power consumers as well, have to comply with the RQS target. In order to

[10] Every four years an evaluation of the level of feed-in tariffs takes place. *In principle*, upward revisions are also possible, should the German government e.g. wish to stimulate expansion towards reaching more ambitious goals.

address the *windfall profits* issue and - last but not least - for reasons of stability of investor's regime, the Alternative II scenario presumes that the certificate-based RQS is combined and integrated with the prevailing SDE system.

To enable its proper functioning, a possible national RQS-SDE support scheme is to meet certain requirements. First of all, the RQS should be designed such that - at least in the initial stage - the relevant competent authority is mandated to use flexible market intervention instruments to ensure that the RQS certificate price remains within a certain projected bandwidth. Generally, the RQS target should be set at a level that the system imposes a binding constraint so that the RQS certificates assume significant minimum value, e.g. above 20 €/MWh. Yet the target should not be set so stringent as to raise the certificate value above the standard (i.e. under 'average' Dutch renewable resource conditions) incremental cost of the cheapest qualifying capital-intensive renewable electricity option with a relatively large potential, such as onshore wind. This is to minimise windfall profits. Then, the SDE support mechanism will level the playing field for all qualifying renewable generation technologies in an approximate fashion. This way the SDE support mechanism in combination with the RQS is due to minimise windfall profits more than the SDE already does at present on a stand-alone basis on account of broadened competition between generators applying different eligible technologies. A possible exception, warranting special attention in preparing system design, might be formed by generators using renewable sources, which face relatively low incremental capital costs. Depending on the plant-specific conditions, this relates notably to co-firing generators.

The reason is that the RQS triggers cost-reducing competition, i.e. not only between generators within one particular SDE category but also between generators falling in different SDE categories on account of the RQS mechanism. This is applicable to the extent that the RQS certificate market is a competitive market. The Dutch electricity wholesale market is fairly concentrated (NMA/Energiekamer, 2008a). Yet the Dutch supply-side of renewable electricity is much more diversified than Dutch electricity supply as a whole. This is brought about by a fairly diversified sector with a major share of a large number of small independent producers on top of integrated companies such as RWE (Essent), Vattenfall (Nuon) and Eneco. On the demand side a number of 'new' entrants such as Electrabel, E-oN, Centrica (Oxxio) and smaller niche players have triggered more competition on the Dutch electricity retail market with gradually more diversification although the market share by the three incumbents RWE (Essent), Vattenfall (Nuon) and Eneco is still high (NMa/Energiekamer, 2008b). Evidently, market concentration is an issue warranting close attention with regard to the RQS certificate market (See also Koutstaal et al., 2008; van Tilburg et al., 2007). Furthermore, we propose an RQS / SDE system, which includes an ex post adjustment mechanism of the SDE premium for the recent evolution of the electricity price and the RQS certificate price. Ex post adjustment of SDE subsidy rates for recorded RQS certificate prices provides further safeguard against windfall profits for those categories needing supplementary SDE support.

Integration of the RQS into the SDE scheme affects the determination of the SDE subsidy rate. The general formula for determining the SDE premium applicable for the past calendar year for a RES-E plant of certain SDE category that was commissioned in a certain vintage year, expressed in €ct / kWh, can now be denoted as follows:

$$s = b - \left(\prod_i a_i \right) \cdot \max\left(p_{el}^{*}, p_{el}^{floor} \right) - p_{ELCERT} \qquad (3.2)$$

s.t. $\mathrm{p}^{floor}_{RQS\ certificate} \leq \mathrm{p}^{*}_{RQS\ certificate} \leq \mathrm{p}^{ceiling}_{RQS\ certificate}$

where:

s = the applicable premium rate, i.e. SDE production subsidy rate

b = the applicable subsidy base rate, depending on SDE category and plant vintage year

p^*_{el} = the realised average electricity price in the past calendar year
p^{floor}_{el} = the electricity price floor, set for the past calendar year
$p_{RQS\ certificate}$ = the realised average RQS certificate price in the past calendar year
a_i = the adjustment rate for adjustment component i (strictly positive)

The side restriction implies that the government is presumed to announce beforehand that it will intervene with policy measures when the RQS certificate price either increases above the RQS certificate price ceiling or decreases below the RQS certificate price floor.

3.2.4 Alternative III: introduction of a joint hybrid RQS with Sweden

The third alternative RES-E stimulation scenario is based on the presumed realisation of a joint support scheme with Sweden as per 1 January 2014. The basic idea behind such a scheme is that within a certificates-based joint RQS support scheme - up to a certain extent and in close bilateral consultation - each of the participating countries have the right to introduce additional supplementary support measures at the national level, provided they are not at odds with the well-functioning of the joint RQS certificate market. In the case of the Netherlands this will be the existing SDE support scheme. The joint support scheme will be integrated into the SDE regulations in much the same way as the national RQS-SDE scheme considered under the Alternative II scenario, as has been explained in the previous sub-section.

The Swedish RQS, called ‘the electricity certificate system’, requires all electricity suppliers and certain electricity users to purchase RQS certificates equivalent to a pre-set target proportion of their respective electricity demand - the so-called quota obligation - set for each calendar year of the Swedish RQS scheme. The scheme became operational as per 1 May 2003 and is scheduled by law to last until the end of 2030. Its main stated purposes are to help increase the production of renewable electricity and reduce emissions of greenhouse gases.

Svenska Kraftnät operates the electronic platform for the Swedish RQS certificates system, the so-called Cesar accounting system. The Swedish Energy Agency acts as supervisory agency of the RQS. The agency is responsible for the compliance enforcement regime and for overseeing the functioning of the RQS certificate electronic platform and the RQS certificate market. The Swedish RQS certificate market is mainly a bilateral contracting market without a central trading platform. Stated reason for this is that a diversity of actors on the supply and demand side has diverging trading requirements (Swedish Energy Agency, 2008). At first sight, information from the CESAR accounting system of the Swedish Energy Agency suggests that the Swedish RQS certificate market is rather liquid with two yearly peaks: the largest one towards 1 April (quota obligation settlement date) and the other one towards the end of the year for accounting reasons. The Swedish Energy Agency and Svensk Kraftmäkling, a private actor, publish price information.

From both an effectiveness and a cost efficiency point of view, the Swedish RES-E support scheme appears to function well. The Swedish support scheme is well on track to meet its pre-set RES-E deployment objectives. RES-E support cost hovers around 30 €/MWh of qualifying RES-E (Jansen, 2010).

In principle, the Netherlands could pursue a joint support scheme with any other Member State. In this report, a joint support scheme with Sweden is chosen for three main reasons. Firstly, the Swedish support scheme appears to function well. Secondly, Sweden is supposed to boast significant RES-E potentials in excess of meeting Sweden’s national 2020 target commitments at much lower cost than the marginal support costs faced by the Netherlands. Thirdly, the Swedish government has stated on various occasions that, in principle, it favours international expansion of the Swedish RQS certificate system.

3.3 Quantitative approach for design of baseline scenario

This study takes a certain intensified variant of the current SDE support system leading to the 35% share as the baseline. Against this baseline, social costs and benefits of selected alternative market support systems will be evaluated. The baseline is largely based on the Reference projections (Daniëls *et al*, 2010), notably the so-called SVV variant with planned or intended policies. The latter variant is in line with the (Dutch) National Renewable Energy Action Plan that the Dutch government has submitted in the summer of 2010. However, the Netherlands' Action Plan leads to a share of 39% of RES-E, whereas the baseline in this report assumed a policy intensification up to 35% of RES-E. For all alternatives a delay of renewable electricity growth is foreseen prior to introduction of the alternative support scheme in 2014. Although this delay need not occur in the baseline, for sake of comparability the baseline also assumes delay of renewable electricity growth prior to 2014, compared to the SVV variant of the Reference projections.

In the baseline, it is assumed that renewable electricity will be supported through a feed-in premium scheme that includes premiums for co-firing of biomass in coal fired power plants. Furthermore, these premiums are robust and sufficiently high. Finally, this feed-in premium scheme becomes financed through a surcharge on the electricity bill of end consumers. Only the feed-in support for installations that started production prior to 2013 will continue to be financed by the government budgets.

In the Dutch National Renewable Energy Action Plan, wind energy capacity grows to 6000 MW onshore in 2020 and 6000 MW offshore slightly after 2020. Co-firing of biomass in coal-fired power plants is supported through subsidies, and is foreseen to realise on average up to 20% co-firing, on energy basis, for all coal-fired power plants in operation. The economic co-firing potential in 2020 is anticipated to be around 10 TWh. The baseline scenario includes a significant rise in electricity production from stand-alone biomass installations, up to 7 TWh in 2020. None of the options are limited by budget ceilings, except for solar PV. Solar PV grows - within the budget ceilings - to about 750 MW. In total, renewable electricity production in the National Renewable Energy Action Plan rises to 51 TWh in 2020, or 39% of total electricity consumption in the Netherlands. In this report, the alternative support schemes are evaluated against the baseline scenario based on an ambition of reaching 35% renewable electricity in 2020 or 45 TWh. For this purpose, the RES-E production from biomass installations has been removed accordingly. Table 3.1 provides an overview of the installed capacity and production of all RES-E options in 2020 in the Reference projections or National Renewable Energy Action Plan scenario.

Table 3.1 *RES-E capacity and production in 2020 in the Action Plan and baseline*

Technology	Capacity [GW]	RES-E production in Renewable Energy Action Plan [TWh]	RES-E production in Baseline Scenario [TWh]
Biomass co-firing	1.3[1]	8.3	6.8
Waste combustion	0.6	1.1	
Biomass digestion	0.6	4.6	4.3
Other biomass	0.3	2.5	
Wind onshore	6.0	13.4	13.4
Wind offshore	5.2	19.0	19.0
PV	0.8	0.6	0.6
Hydro power	0.2	0.7	0.7

[1] Effective capacity of biomass co-firing. The effective capacity corresponds to 20% co-firing with respect to a total coal power capacity of 6,4 GW.

3.4 Generation cost assumptions for the distinct scenarios

The Reference projections form the basis for the projections of the production costs for developers (the subsidy base rates). The subsidy base rates for existing capacity are based on prevailing SDE legislation. As the SDE becomes ampler and more robust in the baseline scenario, the subsidy base rates for future capacity are equal to the projected costs of energy. These future costs of energy are projected in a hybrid approach of the learning curve methodology and market disturbance factors: see (van Tilburg and Lensink, 2009) for a description of the approach.

We expect that differences between scenarios will result due to differences in production costs. The reasons for an increase or decrease of production costs can be diverse and it is difficult to predict how technical-economical parameters or financial parameters of projects will change in a different support scheme. The nature of projects or the nature of active project developers can partly change, which further complicates a detailed analysis of change in technical-economical or financial parameters.

In this section, the expected change in production costs is shown. An explication towards these changes is also provided. However, given the mentioned uncertainty in how cost changes will materialise, the explication should be regarded as merely describing a possible cost evolution.

The differences between the scenarios are assumed to be accounted for by different returns on equity (RoE), not by different debt/equity ratios. Also differences in insurance costs and transaction costs are assumed. For the baseline scenario we assume that the RoE is 15% (out of which also project preparation costs must be funded). For the FIT system the RoE is assumed to be 12% and furthermore the insurance costs and transaction costs are subtracted (in the SDE this is an adjustment component within the base rates (parameter *b* of Equation 3.1). For the RQS the costs are assumed to be the same as in the baseline scenario. However, the insurance costs and transaction costs are subtracted. Table 3.2 indicates what the year 2010 production costs would look like under distinct support systems.

Table 3.2 *Production costs for project developers under three different systems. Costs correspond to projected costs for 2010*

Category	Specification	SDE [€/MWh]	FIT [€/MWh]	RQS [€/MWh]
Waste incineration	23% electrical efficiency	52	51	52
Water treatment plants		60	58	60
Digestion of green municipal waste (GFT)		134	128	108
Biomass co-firing[11]	agricultural residues	11	11	11
Biomass co-firing	wood pellets	35	35	35
Manure co-digestion		183	178	161
Other digestion		-	-	88
Land fill gas		83	80	82
Integrated mono digestion		158	153	147
Combustion of waste wood	small (0-10 MW_e)	198	193	196
	medium (10-50 MW_e)	121	116	119
	large (100-200 MW_e)	-	-	86
Combustion of liquid waste	small (0-10 MW_e)	157	155	157
	medium (10-50 MW_e)	123	122	123
Small scale hydropower	river runoff (<5 m)	123	118	120
Wind onshore	at 2200 full load hours	96	90	89
Wind offshore		175	168	173
Solar PV	15-100 kW_p	430	409	428

[11] For biomass co-firing, the financial gap is shown. That is the difference in production costs of electricity production using coal and electricity production using biomass.

Waste incineration
The renewable electricity production from waste incineration is expected to grow in the next decade, in line with the increase in waste production. Both SDE and FIT offer an indifferent incentive for building low (23%) or high (31%) efficient installations. In the RQS scheme, the revenues from electricity sales and certificate sales are higher than projected for SDE and FIT. Although this does not give an explicit incentive to build high efficiency installations, it does create a better cash flow. That cash flow facilitates the construction of installations that have a higher (technical) risk profile but also higher yield. Waste incineration in the RQS might see higher production costs (up to 62 €/MWh), but also higher potential (+0,3 TWh/year). However, as much is yet uncertain in the waste market, this report assumes no change in type of installations, with production costs roughly equal to the SDE at 52 €/MWh.

Waste water treatment plants and Land fill gas
Land fill gas installations and waste water treatments plants, both industrial and sewage, are often small-scale installations with little affinity with the electricity market. The RQS scheme is not likely to realise more, less expensive or other projects within this category.

Digestion of green municipal waste (GFT), Manure codigestion, Other digestion
The costs for electricity production through digestion of biomass depend on local circumstances, biomass type and installation size. Feed-in schemes such as SDE and FIT have many different tariffs for biomass installations, either specified through distinct categories or specified through several bonuses. Two types of actors can be distinguished:

(1) The suppliers of biomass (farmers, waste processing industry) have little affinity with the electricity market and favour small-scale installations. For them, an RQS scheme does not create significant additional value.
(2) Energy companies that focus on electricity production. They will favour large-scale installation (more than 2 MW_e). The RQS scheme is expected to induce biomass installations to a significant larger scale. Offsite digestion installations with a flexible supply of digestible biomass might even become competitive without additional feed-in premium on top of the RQS certificates. Up-scaling under an RQS to 4 MW_e is presumed; cheaper feedstock supply is not anticipated. Although these 'new opportunities' can be considered somewhat anecdotal, the essence is that it is assumed that an RQS scheme increases the feasibility of unforeseen projects and that the modelling should account for these new opportunities in one way or the other.

Combustion of biomass
In an RQS scheme, dedicated biomass installations might develop without additional SDE support, provided that cost reduction through up-scaling is feasible. Significant up-scaling could lower production costs to below 90 €/MWh for waste wood. However, waste wood is not likely to be acquired in such large quantities. Up-scaled installations will have to use wood pellets as biomass source, which is significantly more expensive. Therefore, these installations will not be able to compete with co-firing. Up-scaling of installations for liquid biomass is not anticipated because of sustainability concerns.

Biomass co-firing
The financial gap of biomass co-firing depends on the prices of coal, CO_2 and biomass. Moreover, this gap depends on location and installation. In all variants, the costs of co-firing are assumed to be identical. The financial gap of co-firing of wood pellets (additional costs of using biomass instead of using coal) is assumed to be 35 €/MWh in 2010, based on a coal price (for 2010) of 2,6 €/GJ, a biomass price of 6,8 €/GJ and a CO_2 price of 15 €/t. Additional operational and maintenance costs due to the co-firing of biomass are assumed to be 3 €/MWh. The assumed electrical efficiency is 40%. For agro residues, the financial gap of a limited potential (<1 TWh/year) is assumed to amount to 11 €/MWh in 2010.

Small-scale hydropower and solar PV
The developments in these categories are not likely to differ between the categories. When the financial gap of solar PV is expected to become negative (i.e. it becomes a commercially viable option), no certificates will be granted in the RQS scheme to new installations from that point onwards.

Wind offshore, wind onshore
Under the RQS scheme, offshore wind will receive supplementary SDE support, hence changes in production costs are not anticipated. For onshore wind, without hybrid support, the actual production costs are much more diverse than the general feed-in subsidy of 90 to 96 €/MWh. Furthermore, under a RQS the production costs are on average reduced by an arbitrary 7 €/MWh for the year 2010. This value is chosen (1) to compensate for the information asymmetry in setting feed-in tariffs by the government and (2) to reflect the up-scaling of individual wind parks and other scale effects due to larger involvement of the energy companies. For offshore wind, the FIT related production costs include grid connection costs. For offshore wind in the FIT alternative, an RoE of 12% for offshore is doubtful, as technological risks are the biggest challenge. For that reason, we used a higher RoE for offshore: 14%. For wind energy, a reduction of production costs over time is projected, based on learning and scale effects. Learning and scale effects are assumed to be identical among the alternatives (see Figure 3.2).

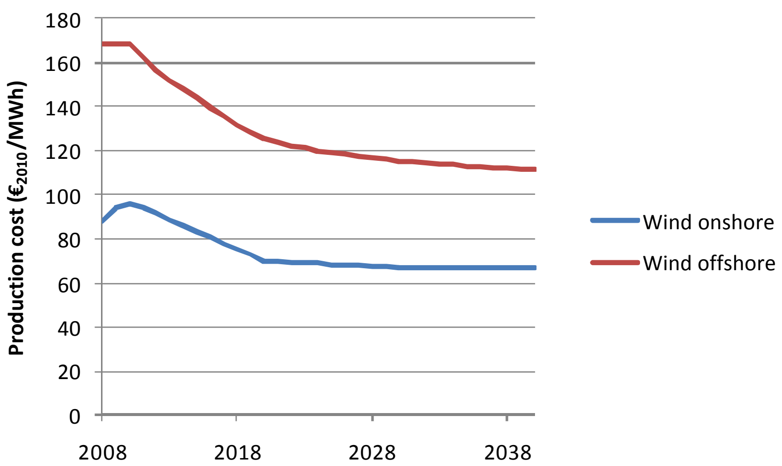

Figure 3.2 *Production cost for wind energy (onshore at 2200 full load hours; offshore at 40 km off the coast of Holland) as function of time for the baseline scenario*

3.5 Balancing costs under the distinct scenarios

Based, among others, on information about the German situation, as presented in Appendix B and Holttinen *et al.* (2008), we make the following assumptions on the incremental *balancing costs for the electricity system*:
- Wind power: see below in this section.
- PV: nil.
- Other RES-E: nil.

Breitschopf *et al* (2010a, 2010b) arrive at quite high figures for RES-E balancing costs in the case of Germany (see Appendix B). Holttinen *et al.* (2008) suggest balancing costs for wind power in the 1- 4 €/MWh interval. The values at the interval's higher end correspond to systems with high wind power penetration. Wind power and to a much lesser extent PV involve most balancing costs for the electricity system on account of their variable and to some extent less predictable random production pattern. As for the balancing cost of wind power, we have applied the data of Figure 3.3, which have been taken from Holttinen (2008).

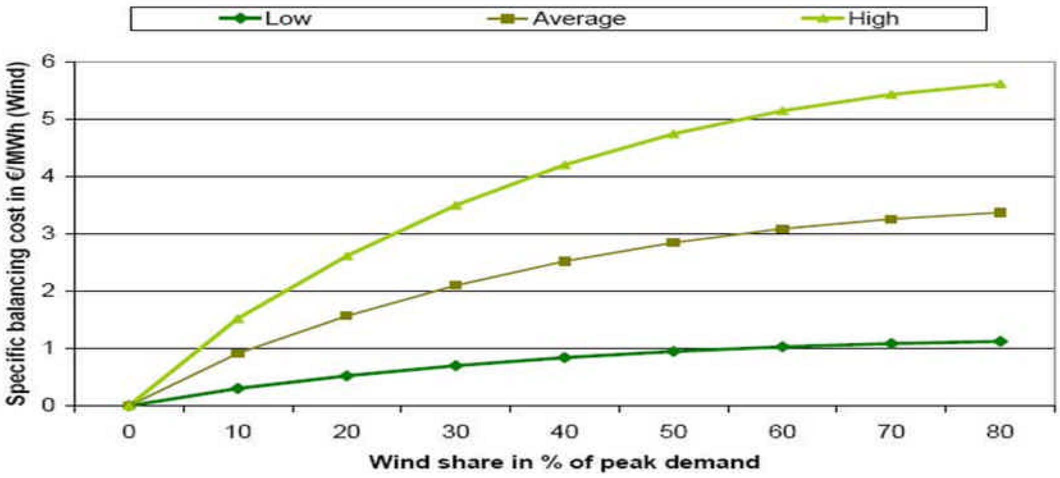

Figure 3.3 *Balancing cost per MWh of wind generation as a function of national installed wind capacity as percentage of national peak electricity demand for three levels of flexibility in electricity generation (from Holttinen, 2008)*

For the baseline and RQS support systems, where RES-E generators are exposed to balancing risk, we have assumed that the 'average balancing cost curve' for wind power as a function of the wind power volume as a percentage of peak demand applies. For the feed-in tariff support system, we have assumed that the 'high balancing cost curve' applies. Major reasons to assign higher balancing cost of wind power to Alternative I are the following:

- Under Alternative I, RES-E generators are exempted from balancing risk. Hence, in their production behaviour they will not be responsive to the balancing cost they cause to the electricity system.
- Under Alternative I, TSO TenneT is held to assume balancing responsibility for all RES-E power which is fed into the public grid under priority rule without any regard to market circumstances. On the one hand, in carrying out this duty, TenneT can capitalise on aggregation advantages (portfolio effect). On the other hand, TenneT is not a load serving entity and hence cannot capitalise on the portfolio effect of aggregating generation sources and loads. This contrasts to the baseline and RQS scenarios, where typical balancing responsible parties will include RES-E quite efficiently into their broad portfolios of generating assets and electricity supply contracts, for all of which they assume aggregate balancing responsibility.
- Another factor that complicates TenneT's duty to balance RES-E under Alternative I somewhat more, is that TenneT does not 'see' individual RES-E plants and their operational status, e.g. where forced outages occur or where they don't.

Figure 3.3 indicates balancing costs for wind power on the order of 2 €/MWh in 2014 under the baseline and RQSs as against 3 €/MWh under FIT. By 2020, at a projected sharp increase of wind power penetration, the corresponding numbers are approximately 2.5 €/MWh and 4.5 €/MWh respectively, and they remain at these latter levels after 2020. This is due to our assumptions about keeping all volumes and RES-E shares constant after 2020.

In sharp contrast to the situation in Germany, the installed base for PV in the Dutch portfolio of generating assets is expected to remain of relatively modest proportions. This holds even in the case a shift to a feed-in tariff system is to be decided upon. Therefore, we have decided to refrain from making allowance for any extra (or any savings on) system balancing cost in the case of PV. Moreover, system balancing costs of other RES-E technologies are broadly comparable to non-RES-E generation technologies. Therefore, we also neglect effects on system balancing costs of RES-E technologies other than wind power and PV.

3.6 Projected RES-E trends under the baseline scenario

The incremental social costs and benefits of the three alternative Dutch RES-E support scenarios will be gauged against the baseline. Hereafter the baseline scenario is set out. Key trends regarding the scenario environment are explained first. Subsequently, the projected RES-E production patterns are discussed. Section 3.6.2 provides an overview of inland renewable electricity production by RES-E technology supported by the SDE. [12]

3.6.1 Trends in the electricity sector

Key trends in the (baseline) scenario environment are: electricity wholesale market prices; inlands electricity supply by physical imports, inlands power generation by conventional power technology and by renewable sources (aggregated); electricity system power losses, gross electricity consumption, and final electricity consumption.

In Table 3.3 the development in the average wholesale market price of electricity is shown for the baseline scenario. Table 3.4 shows key indicators of the electricity production and consumption in the years 2012 to 2020.

Table 3.3 *Average electricity wholesale market price [€ct/kWh]*

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wholesale market price	5.80	5.75	5.81	5.87	5.93	6.00	6.07	6.12	6.20

Table 3.4 *Electricity production and consumption [TWh]*

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Imports[a]	4.1	-4.7	-9.3	-11.7	-11.2	-10.4	-12.3	-17.7	-25.9
Conventional production	104.1	108.3	109.8	112.8	110.7	106.4	105.7	106.2	111.1
RES-E production	15.8	18.4	22.6	23.2	25.8	30.4	34.0	39.9	45.3
System power losses	5.2	5.2	5.3	5.3	5.3	5.4	5.4	5.5	5.5
Gross consumption	120.9	122.0	123.1	124.2	125.3	126.3	127.4	128.5	129.5
Final consumption	115.7	117.2	118.2	119.1	120.0	120.9	122.0	123.0	124.0

[a] Negative imports mean exports

3.6.2 Renewable electricity production by RES-E technology

Capacities of RES-E technologies

It should be noted that the original scenario from the Reference projections is slightly modified for this study. To decrease the RES-E production from 39% in the SVV scenario to 35% in the baseline scenario, production capacity from biomass co-firing and stand-alone biomass technologies has been lowered. In our baseline scenario, wind energy grows to 6000 MW onshore in 2020 and 6000 MW offshore slightly after 2020. Co-firing of biomass in coal fired power plants is supported through subsidies, and is foreseen to reach up to 14.7% co-firing on energy basis, averaged over all coal-fired power plants in operation. The economic co-firing potential in 2020 is foreseen to be above 10 TWh, but in our baseline scenario only 9 TWh is used.

The baseline scenario includes an electricity production of 4.2 TWh from standalone biomass installations in 2020. These options are limited by budget ceilings, and the same applies to solar PV. Solar PV grows to about 770 MW in 2020.

[12] Apart from Alternative III, in all the support scenarios considered net import of target accounting attributes for the purposes of the new renewable energy directive will be assumed to be negligible. Hence, apart from Alternative III the 35% RES-E share will be presumed to be fully achieved by inlands generation of RES-E.

Production by RES-E technologies

Table 3.5 indicates the total RES-E production, differentiated by technology, for the period 2012-2020. The RES-E percentage is calculated by dividing the RES-E production by the gross electricity consumption. Graphically the same results are shown in Figure 3.4.

Table 3.5 *Total RES-E production [TWh/a] for the period 2012-2020*

	2012	2013	2014	2015	2016	2017	2018	2019	2020-2035
Biomass co-firing	5.2	6.8	7.7	8.2	8.8	8.7	8.3	8.9	9.3
Biomass stand-alone	2.4	2.5	2.5	2.7	3.1	3.3	2.8	3.4	4.2
Biomass waste incineration	1.2	1.2	1.2	1.2	1.3	1.4	1.4	1.5	1.6
Landfill gas	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Wind onshore	5.8	6.7	6.6	6.5	8.0	9.5	10.9	12.2	13.1
Wind offshore	0.8	0.8	4.2	4.2	4.2	7.1	10.0	13.0	16.0
Solar PV	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.4
Hydro power	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.6	0.7
Total	16	18	23	23	26	30	34	40	45
RES-E %	13%	15%	18%	19%	21%	24%	27%	31%	35%

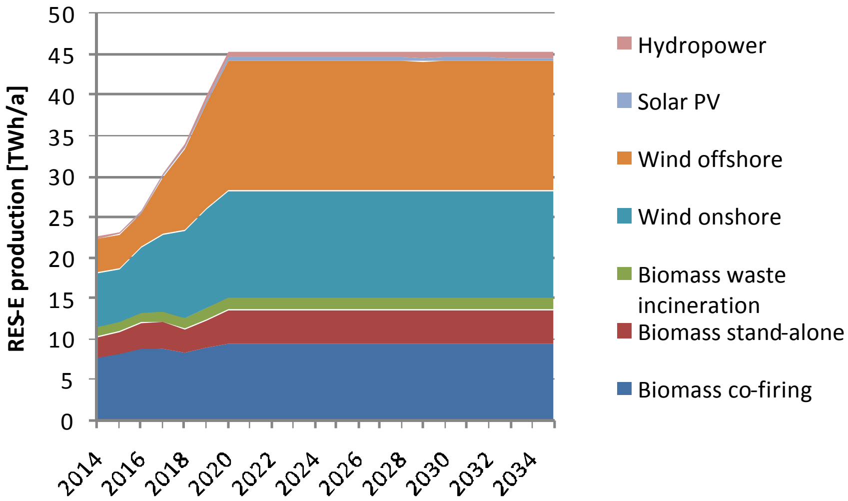

Figure 3.4 *RES-E production [TWh/a] for the baseline scenario*

Projected SDE premium payments

Consequential to the development of RES-E production, the investment in new generation capacity will peak at or before 2020. After 2020, existing capacity continues to generate renewable electricity for many years. Around 2035 - in the base line scenario - reinvestments (mainly in offshore wind) will cause the annual premium payments to increase.

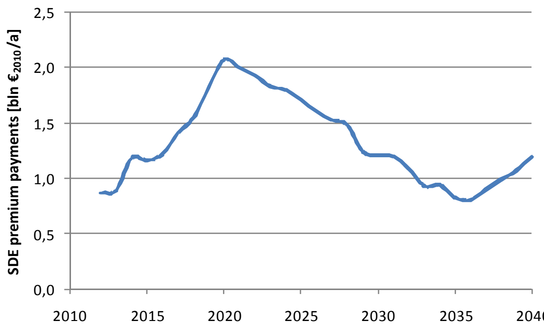

Figure 3.5 *Projected SDE premium payments*

4. The German-like feed-in tariffs scenario

4.1 Introduction

This chapter describes and analyses Alternative I, i.e. a feed-in-tariff (FIT) system for the Netherlands comparable to the German EEG support scheme, and conducts a cost-benefit analysis of this alternative Dutch RES-E stimulation scheme against the baseline scenario, which was explained in the previous chapter.

The design of the Alternative I scenario is introduced in Section 4.2. It starts with a description of distinct key features of the German Feed-in Tariffs and then discusses some main scenario assumptions for Alternative I. Section 4.3 gives an overview of projected trends for the RES-E sector under the FIT regime. Results of the cost-benefit analysis of Alternative I against the baseline scenario from the perspective of Dutch society are explained in Section 4.4. Section 4.5 considers major distributional effects for distinct stakeholder categories. Section 4.6 winds up this chapter with concluding observations.

4.2 On the design of Alternative I: the German-like support scheme

Before further elaborating on Alternative I, introduction of a *Feed-In Tariffs* scenario in the Netherlands, a brief description of the German feed-in tariffs system in this section is in order. More information is given in Appendix B.

4.2.1 Brief description of the German approach to market stimulation of renewable energy

The EEG - *Gesetz für den Vorrang Erneurbarer Energien (Erneurbare-Energien-Gesetz)* - was introduced in 1990. It was based on the precursor law, the *Stromeinspeizegesetz*. By force of the EEG, operators of plants generating electricity from renewable energy sources are legally entitled to a fixed compensation for electricity fed into the grid, to be paid by the grid operator.[13] In most cases the guarantee to the technology-specific fixed EEG tariff is valid for 20 years without any reductions in the tariff during this period. Moreover the tariffs for new vintages of installations are liable to certain pre-set technology-specific digressions, intended to be in line with the reduction in the expected levelised cost of electricity for newer vintages.

In order for technologies to qualify for EEG support, the power produced by the installations concerned has to be based for 100% on renewable energy sources. Hence, biomass co-firing is not eligible, nor does power generation on the basis of the biogenic part of solid municipal waste qualify. Moreover, for biomass-based installations an upper capacity limit of 20 MW exists (Lensink *et al.*, 2008).

Several revisions have been made to the EEG law, the last one in 2009.[14] The German approach has proved to be quite effective in terms of fostering the production of renewable electricity (and other forms of energy from renewable sources). The German success in achieving fast market penetration of renewables - very effectively marketed in Europe and overseas by BMU, the German federal ministry, responsible for implementation of the EEG law - has been credited

[13] The infant industry protection idea on which the EEG is based dates back to the nowadays widely forgotten but nonetheless, qua ideas, in Germany and far beyond very influential German economist Friedrich List, who lived in the first half of the 19th century.

[14] See: http://bundesrecht.juris.de/eeg_2009/

all over the world. In the Netherlands the German approach also commands strong support among certain Dutch stakeholders, e.g. RES-E project developers.

Highlights of the evolution of renewable electricity generation and the associated EEG-mandated payments during the period 2000- 2009 are shown in Table 4.1. The table shows a remarkably fast penetration of EEG power relative to aggregate final power use. EEG power has risen from 10.4 TWh in 2000 (months April-December only)[15] to 75.1 TWh in 2009. The other side of the coin is that EEG-mandated payments have increased at an even faster rate. In 2009 the average EEG payment amounted to 14.0 €ct/kWh or more than double the average price of electricity on the German wholesale market in that year. As a result, aggregate EEG payments to EEG-eligible power producers have risen from € 0.9 billion in the last 9 months of 2000 to € 10.8 billion in 2009. The incremental procurement costs of EEG power with respect to the reference average day-ahead wholesale price amounted to € 5.3 billion in 2009 (IfnE, 2010).

Table 4.1 *Evolution of EEG power generation and EEG-mandated payments in Germany, 2000[1] - 2009*

Year		2000	2002	2004	2005	2006	2007	2008	2009
EEG power generation, of which	**TWh**	**10.4**	**24.3**	**38.5**	**44.0**	**51.5**	**67.0**	**71.1**	**75.1**
Hydropower (small-scale)[3]	(%)	39.6	26.3	12.0	11.3	9.6	8.3	7.0	6.5
Biogas[3]	(%)			6.7	7.1	5.4	4.1	3.1	2.7
Biomass, solid[4]	(%)	5.6	9.8	13.6	16.8	21.1	23.8	26.6	30.6
Geothermal	(%)	-	-	-	-	-	-	-	-
Wind onshore	(%)	54.5	63.2	66.3	61.9	59.6	59.3	57.0	51.4
Wind offshore	(%)	-	-	-	-	-	-	-	-
Solar PV	(%)	-	0.7	1.4	2.9	4.3	4.6	6.2	8.8
Average EEG payment	**€/MWh**	**85**	**89**	**93**	**100**	**109**	**114**	**123**	**140**
Power delivered to non-privileged end-users	TWh	345	465	488	492	495	495	494	466
Power delivered to privileged end-users (Art.'s 41/42 EEG)[2]	TWh	-	-	36.9	63.5	70.2	72.1	78.0	65.0
Resulting EEG-quota for non-privileged end-users	%	3.0	5.4	8.5	10.0	12.0	15.7	17.1	18.6
Average EEG surcharge for non-privileged end-users	**€/MWh**	**0.2**	**0.3**	**0.4**	**0.6**	**0.8**	**1.0**	**1.1**	**1.2**
Total EEG payments (excl avoided network charges)	**€ bln**	**0.9**	**2.2**	**3.6**	**4.5**	**5.8**	**7.9**	**9.0**	**10.8**

Notes:
1) Months April-December only.
2) Since July 2003, so-called privileged large power-intensive users are held to contribute an EEG surcharge of 0.05 €ct / kWh.
3) For the years 2000 up to 2003 the share of hydropower includes biogas.
4) Biomass co-firing is not eligible for EEG support.
Source: BMU, IfnE, UNB, BWED

The German transmission and distribution network system is split up in four separate TSO control regions. In order to prevent that divergent EEG apportionment costs by region result in different apportionment charges to consumers, a horizontal equalisation scheme (*Horizontaler Belastungsausgleich*) is in place. This equalisation scheme redistributes the EEG apportionment costs between TSOs, so that consumers have to pay the same EEG surcharges per kWh throughout Germany (Deutscher Bundestag, 2010).

Up to 2009 the EEG power fed into the grid was transformed by TSOs into in a monthly base-load bundle of EEG power delivered physically to small-scale end users through a complex sys-

[15] No statistics on the whole year 2000 have been published in the documents reviewed by the authors.

tem. This EEG power allocation system implied high EEG power planning deviation (imbalance price and volume) risks for retail suppliers and traders on their behalf. Traders used to balance actual feed-in of power by renewable energy producers with the TSO-predicted monthly base-load bundle through power purchase or sale transactions on wholesale energy markets. Costs of the traders were passed through in the grid fees; hence incurred costs were lacking transparency to power end-users. Moreover, compulsory information provision demands on suppliers and traders to enable determination of the add-on-the-bill of end-users denoted a high administrative burden. This so-called EEG enhancement procedure (*EEG Veredelung*) caused increasingly high costs, warranting regulatory adjustment (Börkey and Jahn, 2010).

EEG-benefitting power producers sell their produce to their respective DSO (distribution network operator) at preferential EEG tariffs. In accordance with secondary legislation in force since early year 2010, '*AusglmechV*'[16], the DSO invoices his TSO (transmission system operator) for reimbursement for the EEG outlays made. As in the past, under current EEG regulation EEG-benefitting power producers do not run balancing risk and do not even have a production schedule notification duty.[17] What is new, however, is that under *AusglmechV* this risk is assigned by force of the EEG to the TSO concerned, who is now mandated to market EEG power fed into the public grid in his control area. The TSO notifies the Bundesnetzagentur of projected EEG power injections into his network and runs the risk of deviations of notified projected injections with EEG power realisations. Each TSO withdraws EEG-related expenses from a special market transactions fund for EEG power. This fund is replenished by a special allocation from the proceeds of the EEG surcharge (*EEG-Umlage*). This surcharge on the bill is footed by the end-users (almost 600 large energy intensive consumers are largely exempted).[18] In this way, traders and suppliers are sheltered from the EEG power related imbalance risk.[19] Suppliers now only face the administrative cost of passing on the EEG surcharge. Furthermore, the current EEG surcharge includes the balancing costs. Before implementing *AusglmechV* these costs were hidden for end-users in the network-services surcharge. These regulatory reforms are significant improvements, reducing overall incremental system balancing cost and price risks as well as the administrative costs of non-TSO market parties, whereas administrative costs for the TSOs will rise. Moreover, a step towards more transparency of the social cost of EEG support is made, as balancing costs, associated with EEG power injections, are now being accounted for in the *EEG-Umlage*. Yet the external costs of the shift of a variety of other market risks from EEG beneficiaries to other market participants still remain to be accounted for.

A major issue of policy relevance is the recent steep rise in the *EEG-Umlage*. In 2008 and 2009, this surcharge to non-privileged power end-users amounted to 1.1 €ct/kWh and 1.3 €ct/kWh respectively; in 2010 non-privileged customers[20] had to pay 2.05 €ct/kWh. The latter amount is

---

[16] The full name of this regulation adopted on 17 July 2009 and implemented as from 1 January 2010 is: *Verordnung zur Weiterentwicklung des bundesweiten Ausgleichmechanismus.*

[17] The Fraunhofer ISI institute has made a proposal to introduce a 'gliding (feed-in) premium' option, broadly in line with the current Spanish system (Sensfuß and Ragwitz, 2009). Adoption of this proposal would further increase the visible part of the total EEG cost to German society. E.g. for power from wind power operators opting for the proposed alternative option the apparent cost to German society would rise by 15,2 €/MWh, compared to the going EEG tariff. This relates to commodity price risk which, under the choice for a feed-in tariff, is absorbed by non-EEG market parties and ultimately by and large by the end-users. The 15,2 €/MWh additional cost do not include incremental network cost impacts and before introduction of *AusglmechV* neither cost impacts on system balancing. So far the German federal parliament (Bundestag) has put the gliding premium option amendment on hold.

[18] For year 2010 an EEG surcharge is levied on the kWh price for households of 2,047 €ct / kWh, whereas for energy-intensive companies the EEG surcharge is limited to 0.05 €ct / kWh (Deutsche Bundestag, 2010).

[19] Non-EEG power producers sell power on the EEX or bilaterally to power suppliers/traders and run balancing risk. This risk refers to deviations between their ex ante notified (contractual) injections and their realised injections into the public grid. The non-EEG producers have incentives to minimise their deviations since they are part of a balancing responsible party (*Bilanzkreisverantwortliche*).

[20] BMU distinguishes between *privileged consumers*, i.e. end-users with a large electricity consumption who contribute 0.05 €ct per MWh of electricity consumption to the EEG, and *non-privileged consumers*, paying the full *EEG-Umlage.*

based on ex ante differential EEG cost projections for 2010. The ex ante cost projections for 2010 turned out to be much too low. Differences between ex post actual figures and ex ante projections need to be accounted for in the *EEG-Umlage* of 2011. In June 2010 BMU reckoned with an *EEG-Umlage* for 2011 in the order of 2.7-2.8 €ct/kWh. As per 31 August 2010, BMU had to tentatively increase the estimate of the EEG surcharge on the household electricity bill for 2011 to between 3.2 and 3.5 €ct/kWh (BMU, 2010b). On 14 October 2010 it was announced that the *EEG-Umlage* of 2011 will be fixed at 3.53 €ct/kWh. Main reasons for the fast rise in the EEG surcharge for non-privileged end-users are:

- The open-ended character of the EEG support, which stimulates in particular the eligible technologies with the highest cost gap. Such technologies, apart from the EEG support, are the most risky ones from a project developer's perspective. In recent years the share of PV and other high-cost biomass-based EEG-eligible technologies in the portfolio of EEG power rose spectacularly. In 2009 Amprion expected solar PV to contribute 8.3 TWh of the expected total of 90.2 EEG power in 2010, and to account for €3.8 billion of the anticipated €12.7 billion mandated transfers to EEG-eligible power producers (Deutscher Bundestag, 2010). It appears that Amprion projections regarding the PV feed-in volume will be significantly exceeded (Bode and Groscurth, 2010).
- The effectiveness of the EEG in raising the share of EEG power in the total German power production.
- Recently bearish power markets with EEX base load power prices receding from peak levels reached in year 2008 as a result of the intervening economic crisis. This has a - possibly temporary - large upward impact on the differential costs of EEG eligible RES-E technologies.
- Increased transparency regarding EEG-related incremental costs, introduced by *AusglmechV* regulatory reforms. As a result of these reforms the balancing cost associated with the marketing of EEG power are also included in the *EEG-Umlage* whilst these were previously hidden in the general network system charges.[21]

A large part of the ongoing steep rise in EEG expenditure relates to trends, independent of the type of support scheme. This relates especially to the rising volume of supported renewable electricity, given the need to comply with EU legislation as well as the evolution of wholesale power prices. A key difference of the EEG compared to most alternative support schemes is the open-end nature of currently high-cost renewable generation technologies. BMU emphasises the positive impact of this feature on cost-reducing innovations. As a result, BMU expects that 'in the medium run' the average incremental cost of EEG power and with it the *EEG-Umlage* will come down (BMU, 2010b). This BMU opinion is not shared by all German analysts of this topic: most of the extra EEG power needed for target compliance will have to be contributed by high-cost options, notably offshore wind. Major uncertainties in this regard are future wholesale power price trends and cost evolutions of major EEG-supported technologies.

Although the newly in place *AusgleichV* regulations denote a significant improvement of the EEG implementation, the German government implicitly acknowledges that major problems with the integration of EEG power into the German electricity system still exist. The *Energiekonzept* document launched by the German government in September 2010 (Bundesrepublik Deutschland, 2010b) dedicates one chapter to how to address the challenges concerned:

- Accelerated expansion of networks.
- Introduction of 'smart grids'.
- Stepwise market and system integration of renewables.
- Expansion of energy storage facilities.

[21] The incremental cost for system redispatch in case of local network congestion and other incremental network related costs are still socialised in the general network system charges. It is difficult to obtain transparency on these counts, notably on incremental network reinforcement costs.

Regarding the first bullet point, the first DENA study of 2005 on integration of wind power identified the urgent need to expand the German transmission network by 850 km, but less than 100 km has been realised so far. Meanwhile, the requirement for transmission network expansion has been raised to 3500 km for the period up to 2020 (Stratmann, 2010).

The third bullet point is quite relevant in the context of this report. The idea was floated by Fraunhofer Institute (Sensfuß and Ragwitz, 2009) to introduce a Spanish-like reform to give EEG beneficiaries the option to choose either for the existing feed-in tariffs or for feed-in premiums will be further explored by the German government. Feed-in premium beneficiaries are more market-oriented than feed-in tariff beneficiaries: the former, unlike the latter, run commodity price risks and imbalance risks. Indeed, the EEG legislation as it stands now, with EEG beneficiaries completely shielded from market signals, poses a great obstacle to a successful implementation of 'smart grids' concepts. Fundamental to the well-functioning of smart grids is that electricity system participants are highly reactive to market (price) incentives. The aforementioned proposal of Fraunhofer Institute is still on the German political agenda, as evidenced by the *Energiekonzept* policy document. Its adoption would largely transform the current feed-in tariff system into a feed-in premium system (provided the feed-in premiums are set at attractive levels) and thus the German system would evolve closer towards the Dutch SDE support scheme. The flip side would be that the external effects of the mandatory shift of market risks from RES-E generators to other market players would disappear with a consequential further upward pressure on the *EEG Umlage*. This financial consequence has so far withheld the German Bundestag from approving the optional feed-in premium proposal.

AusgleichV mandates the German TSOs to sell the expected EEG power feed-in at each hour the next day on the Day-Ahead power market. In principle, the duty of TSOs to directly market EEG power also applies to hours of extremely negative prices down to a minimum at the EEX of - 3,000 €/MWh. In 2009 negative power prices were registered for a total of 71 hours (Andor *et al.,* 2010). The very high costs at hours of negative market prices ultimately have to be borne by the unprivileged end consumers. In order to mitigate such cost consequences, *AusgleichV* allows certain exemptions to the duty towards non-price-constrained direct marketing of EEG power under certain conditions. Should such conditions prevail, TSOs will be allowed to submit price-constrained bids for a certain maximum number of hours per year: bid prices should then still be negative in a randomised way. When not all offered EEG power can be sold this way on the Day Ahead market, all other marketing options must be explored: the Intraday market, the EEG (regulating power) reserve, or striking deals with conventional generators to ramp down. Ramping down of EEG installations is allowed only if all of these options fail to bring sufficient solace. This way *AusgleichV* seeks to infringe the priority network access principle for EEG installations to the lowest possible extent.

Andor *et al.* (2010) have floated an interesting proposal to importantly reduce social welfare loss of the priority access principle, and especially of EEG power injections at potentially surplus supply hours. They propose that as a general rule, and not in certain exceptional situations as specified by *AusgleichV*, TSOs will submit price-constrained bids for EEG power on the Day Ahead and Intraday markets. Ultimately, the recommended level of these price bids should be in line with the (technology-specific) short-run marginal cost (SRMC). For wind power the SRMC might be zero, whilst for biomass-based RES-E technology the SRMC might relate to the biomass throughput cost. In case EEG power plants will not be deployed to capacity, their operators should then be entitled to a curtailment fee equal to the applicable feed-in tariff minus the SRMC saved. We concur with Andor *et al.* that adoption of their proposal would denote a fundamental reform to significantly improve social cost efficacy of the EEG.

4.2.2 Main assumptions underpinning the Alternative I scenario

The Alternative I support scheme results in broadly lower generation cost per MWh per technology; the commercial risk profile for project developers (and their financiers) improves, compared to the baseline scenario. The projected generation costs per technology under Alternative I have been explained in Section 3.4.

Under the Alternative I scenario the following risks shift from RES-E project developers/operators to other electricity system stakeholders:

- Imbalance risk: RES-E operators get priority grid access and are exempted from balancing responsibility including the submission of production schedules to the TSO. TSO TenneT will assume the balancing responsibility related to the feed-in of RES-E and will pass on the associated costs to end-users through the specified FIT surcharge on the electricity bill of non-privileged end-users (households and other low/medium voltage end-users);
- Commodity price and demand-side volume risks: RES-E generators are completely shielded from these risks. In a similar manner as the *AusglmechV* regulations in Germany, TenneT will assume this risk as well. TenneT will pass on the differential costs between feed-in tariffs paid out to RES-E generators and the commodity price fetched by TenneT on RES-E sales on the APX day-ahead market. These differential costs will be imposed on non-privileged end-users through a dedicated FIT surcharge.

In principle, the open-ended character of the Alternative I support scheme in combination with the elimination of both balancing and commodity price as well as demand-side volume risks for RES-E generators will favour especially capital-intensive and to a lesser extent intermittent technology. This is for example proven by the astounding rise of PV penetration in Germany. Besides, FIT is quite attractive for small-scale project developers that do not have the resources to manage market and balancing risks. In practice, *RES-E portfolio deviations from the baseline scenario* in the Netherlands will be severely constrained by supply potentials. The assumptions on the RES-E technology mix will be further explained in the next section on trends in the electricity sector.

The assumptions on *system balancing costs* occasioned by RES-E generators have been explained in Section 3.5.

Replacing the prevailing RES-E stimulation scheme by an alternative stimulation scheme implies incremental *regulation costs* to electricity system stakeholders. We will assume one-off overnight 'investment cost' as per ultimo 2013 for the public sector in terms of preparations, consultations, outreach, and implementation of Alternative I scheme to amount to € 10 million. Regarding the recurrent cost for the public sector, we will assume that these are at the same level as the baseline (SDE) scheme. For TSO TenneT we will assume that the office cost for administering the Dutch FIT power marketing fund amounts to € 0.5 million per year. We will neglect the incremental administration cost for electricity suppliers to impose the FIT surcharge to their customers and to pass on the proceeds to the TenneT-administered FIT power marketing fund. The reason is that in the baseline suppliers are also assumed to impose a (SDE-) surcharge to the end-users as from year 2013.

4.3 Projected RES-E trends under Alternative I: FIT

Section 4.3 provides an overview of projected installed renewable electricity generation capacity and renewable electricity production under the FIT support scenario. Apart from Alternative III, in all the support scenarios considered net import of target accounting attributes for the purposes of the new renewable energy directive will be assumed to be negligible. Hence, apart from Alternative III the 35% RES-E share will be presumed to be fully achieved by domestic generation of RES-E.

4.3.1 Projected production by RES-E technologies

Table 4.2 indicates the total RES-E production, differentiated per technology, for the period 2012-2020 for a mix that is the same as in the baseline scenario and for a mix that evoluates differently from the baseline. This way, the sensitivity of project results for projected divergent RES-E mix evolutions can be gauged. Figure 3.4 (same mix) and Figure 4.1 (different mix) give a graphical insight into the projected RES-E mix evolutions.

Table 4.2 *Total RES-E production for the period 2012-2020*

[TWh]	2012	2013	2014	2015	2016	2017	2018	2019	2020
Baseline scenario									
Biomass co-firing	5.2	6.8	7.7	8.2	8.8	8.7	8.3	8.9	9.3
Biomass stand-alone	2.4	2.5	2.5	2.7	3.1	3.3	2.8	3.4	4.2
Biomass waste incineration	1.2	1.2	1.2	1.2	1.3	1.4	1.4	1.5	1.6
Landfill gas	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Wind onshore	5.8	6.7	6.6	6.5	8.0	9.5	10.9	12.2	13.1
Wind offshore	0.8	0.8	4.2	4.2	4.2	7.1	10.0	13.0	16.0
Solar PV	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.4
Hydro power	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.6	0.7
Total	16	18	23	23	26	30	34	40	45
RES-E %	13%	15%	18%	19%	21%	24%	27%	31%	35%
FIT scenario									
Biomass co-firing	5.2	6.8	7.7	8.2	8.8	8.7	8.3	8.9	9.3
Biomass stand-alone	2.4	2.5	2.5	2.7	3.3	4.2	4.6	5.7	6.5
Biomass waste incineration	1.2	1.2	1.2	1.2	1.3	1.4	1.4	1.5	1.6
Landfill gas	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Wind onshore	5.8	6.7	6.6	6.5	8.0	9.5	10.9	12.2	13.1
Wind offshore	0.8	0.8	4.2	4.2	4.2	4.6	7.6	10.6	13.5
Solar PV	0.1	0.1	0.1	0.2	0.3	0.4	0.4	0.5	0.6
Hydro power	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.6	0.7
Total	16	18	23	23	26	29	34	40	45
RES-E %	13%	15%	18%	19%	21%	23%	26%	31%	35%

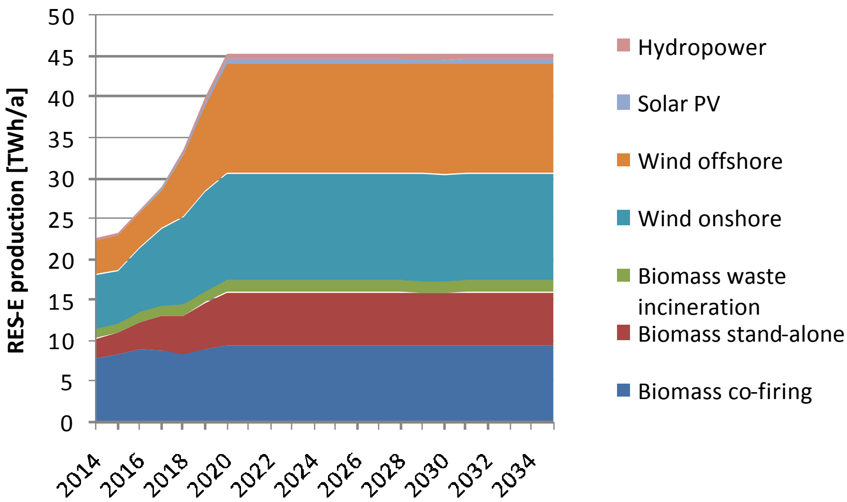

Figure 4.1 *RES-E production [TWh/a] for the FIT variant*

It has been projected that FIT will benefit small-scale options implemented by non-utility actors such as farmers. This can also be witnessed in the development of the RES-E mix in Germany. In our projections this goes somewhat at the expense of the very large-scale option wind offshore. Besides (small-scale) biomass stand-alone also PV is projected to gain but to a substantially more limited extent than in Germany.

4.4 Cost-benefit analysis of Alternative I

4.4.1 General overview

The annual cash flows of (positive or negative) net costs resulting from a shift from an intensified SDE support scheme to a German-like FIT support scheme as per 2014 are shown in Table 4.3.[22] For each cost item, the amounts shown result from the projected differential annual cost of the alternative support scheme considered compared to the baseline (SDE) support scheme. Positive (or negative) figures indicate lower (or higher) costs for the alternative support scheme than the corresponding baseline cost.

Table 4.3 *Shift to Alternative I: FIT - Annual incremental net benefits*

[million €$_{2010}$]	2012	2013	2014	2015	2016	2017	2018	2019
Savings on differential RES-E costs			-3	-6	-28	97	17	-8
Savings on imbalance costs wind power			0	0	-2	0	-8	-18
Extra regulation costs public sector		-10						
Extra regulation costs TSO			-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
Total	**0**	**-10**	**-3**	**-7**	**-31**	**97**	**8**	**-27**
Net benefits without RES-E mix chance	*0*	*-10*	*-0*	*1*	*10*	*32*	*53*	*71*
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Savings on differential RES-E costs	21	24	28	31	32	29	15	3
Savings on imbalance costs wind power	-29	-30	-32	-33	-34	-34	-34	-34
Extra regulation costs public sector								
Extra regulation costs TSO	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
Total	**-9**	**-7**	**-5**	**-3**	**-2**	**-5**	**-19**	**-31**
Net benefits without RES-E mix chance	*86*	*85*	*85*	*85*	*84*	*78*	*62*	*48*
	2028	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Savings on differential RES-E costs	-8	-58	-89	-106	-193	-203	-189	-194
Savings on imbalance costs wind power	-38	-40	-40	-40	-40	-40	-47	-47
Extra regulation costs public sector								
Extra regulation costs TSO	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
Total	**-46**	**-99**	**-130**	**-147**	**-234**	**-244**	**-236**	**-241**
Net benefits without RES-E mix chance	*44*	*36*	*34*	*33*	*18*	*-2*	*-4*	*-19*

The increasingly negative benefits in the period after 2025 have several causes. The RES-E generation costs for wind energy and solar PV decline in time whereas the generation costs from biomass installations is not assumed to decline in time. Although the generation costs of wind energy decline in time, the imbalance costs of wind power are increasing in time. The imbalance costs become an increasingly dominant cost factor in time. Another obscuring factor in the evolution of the benefits is the replacement investments for old RES-E installations (as the total RES-E generation is modelled to remain constant post 2020). For example, wind projects are expected to produce electricity up to five years after the subsidy has ended, due to its low marginal production costs. In the period 2025-2030, some wind projects' SDE grants will expire, although production has not ceased. Especially in the period 2030-2035, several offshore wind farms are modelled to be replaced. The replacement investments that are necessary after 2030 depend on the RES-E mix at that time, see also Figure 3.5.

22 Negative net benefit amounts refer to net costs.

A similar table could have been compiled for the case including the projected divergence in RES-E evolution. We have refrained to do so for reasons of preventing an overflow of information. We revert to the latter case in the presentation of summary results in Section 4.4.4 below.

4.4.2 Savings on differential RES-E costs

Annual differential costs of total final RES-E consumption from a social perspective include[23]:

1. -/- the annualised investment costs of domestic RES-E generation plant facilities.
2. -/- the annual recurrent costs including operation and maintenance cost and, if applicable, fuel cost of domestic RES-E generation plant facilities.
3. -/- the extra system balancing costs of wind power: for alternatives with less wind power than in the baseline - other factors remaining the same - there are cost savings; this item is shown separately as the second item in the cash flow tables (Table 4.3)
4. -/- the costs of net import of RES-E certificates in case of a joint support scheme (applies to Alternative III only)
5. +/+ the cost of the total volume of final RES-E consumption based on the average wholesale power price over the year concerned, (ideally) weighted by hourly power prices and aggregate hourly final electricity consumption volumes.

To establish feed-in premium and feed-in tariff levels, the public sector seeks to allow for:

6. The technology-specific different time profile of power production: compared to the time profile of aggregate gross power consumption, PV power is typically produced more during high-power-price hours and wind power on average more during low-power-price hours.
7. The so-called merit-order effect: compared to power from non-RES sources, power from intermittent renewables is produced at the lowest marginal cost. Hence, power from intermittent renewables tends to displace non-RES power. Consequently, at least in the short run power injections from intermittent renewables have a downward price impact on the wholesale power market.

Items 6 and 7 are somewhat confusingly called ‘the profile factor’ in the SDE regulations. However, from a societal perspective the latter two effects are considered distributional effects rather than costs to society at large.

The cash flow table (Table 4.3) shows *incremental net benefits* of the alternative support system with respect to the baseline scenario. In case of extra costs relative to the baseline, the net benefits are negative and the cash flow concerned has a negative sign.

It can be concluded that, *keeping the RES-E mix and the RES-E volume the same as in the baseline scenario*, the FIT system tends to yield annual net benefits regarding generation costs which are mostly positive and which tend to slightly dominate the negative cash flows on account of extra balancing costs of wind power and extra regulation costs. In interpreting this result, it has to be noted that the extra social costs under FIT of the passing on of a range of market risks from RES-E operators to other market players has only partially been internalised, i.e. the extra system costs of wind power balancing. We have refrained from internalising the other social costs of mandatory passing on all kinds of market risks to other market players, as this would imply having to use arbitrary and controversial assumptions.

Including the projected changes in the RES-E mix with the same aggregate RES-E volumes, the FIT system tends to lead to negative results regarding savings on differential RES-E costs. The key underlying factor is that according to our projections the RES-E mix will evolve with over-representation of more expensive small-scale RES-E technologies as compared to the baseline.

[23] (Differential) Costs indicated with a negative sign and benefits with a positive sign.

The FIT system tends to yield negative net generation cost benefits with respect to the baseline scenario. The positive net benefits regarding notably the cost of offshore wind tend to be more than offset by the negative net benefits for biomass stand-alone. This relates to our assumption that relative to the baseline FIT will boost especially high-cost small-scale options such as biomass stand-alone with lower volume expansions for notably large-scale options such as wind offshore.

Table 4.3 indicates in conformity with our assumptions (see Section 3.5) that a shift to Alternative I implies higher system balancing cost on account of wind power injections. This effect is more pronounced at higher penetration rates for wind power in the overall electricity mix. Note that this effect is moderated by the effect of the diverging projected RES-E mix: Alternative I is projected to have a lower volume of offshore wind.

As already stated, we have disregarded the costs passed on to other electricity system stakeholders with respect to commodity price risk, and demand-side commodity volume risk. TenneT covers this risk first and subsequently passes it on through electricity suppliers to non-privileged end-users through a variable surcharge on the bill. Just like German TSO counterparts TenneT itself is facing financing cost risk when the FIT surcharge established ex ante before a calendar year does not prove sufficient, as the German TSOs have experienced in 2010. This might impact adversely on borrowing conditions to cover TenneT's financing needs. Moreover, in the baseline 'programme responsible parties' deal with the balancing risk of RES-E operators, who is in a better position to do so at lower social costs than TenneT Furthermore, in the last paragraph of section 4.2.1 it was explained that *AusgleichV* regulations to minimise the infringement on the RES-E access priority principle and only under extreme power market conditions result in significant social welfare loss. Lastly, most power consumers − households and the non-privileged business sector − face the disutility of uncertainty regarding next year's FIT surcharge. Power demand reactions might have a negative effect on the power supply business. Again we have not quantitatively internalised these negative external effects, to avoid making use of arbitrary and controversial assumptions.

4.4.3 Regulation costs

Replacing the prevailing RES-E stimulation scheme by an alternative stimulation scheme implies incremental *regulation costs* to electricity system stakeholders. As explained in Section 4.2.2. we have assumed one-off overnight 'investment cost' as per ultimo 2013 for the public sector in terms of preparations, consultations, outreach, and implementation of Alternative I scheme to amount to € 10 million. For TSO TenneT we have assumed that the office cost for administering the Dutch FIT power marketing fund amounts to € 0.5 million per year.

4.4.4 Net present value of annual net benefit cash flows

To show the sensitivity of the real[24] discount rate to the net present value (NPV) projections, we have applied rates of 0%, 2.5% and 5%. The choice of discount rate is not devoid of subjective preferences. As explained in Section 2.5, a Dutch working group on discount rates to be applied fairly recently recommended a real discount rate of 2.5% per year, to be raised for macroeconomic risks and, if possible, non-systemic project risks (Werkgroep Actualisatie Discontogroep, 2007). As explained in Section 2.3, in this study we have applied a real discount rate of 2.5%. To indicate the sensitivity of the results for the choice of discount rate we also calculated NPVs (net present values) at a 0% and at a 5% discount rate. To clarify the more near-term impact of a change from the baseline scenario to the Alternative I scenario, we calculated the projected

[24] A real discount rate is roughly equal to the projected nominal discount rate applicable to projected cash flows in current prices minus the projected rate of general price inflation. Our cash flow analysis is based on cash flows at a constant general price level of year 2010, i.e. 'at prices of to-day'. The recommended nominal discount rate with a projected rate of inflation of 2% would be for the present study: ≈ 2.5% + 2% , i.e. ≈ 4.5%.

NPV of differential cash-flows for the period 2013-2020. More structural trends can be observed from the projected NPV for the period 2013-2035 and its difference with the one for 2013-2020.

The resulting NPV values are shown in Table 4.4. Applying the recommended 2.5% discount rate, our projections indicate that a shift from the baseline support scheme to a German-like feed-in tariff support scheme would reduce the overall direct costs of RES-E support to the Dutch society by 0.2 billion euro (at prices of year 2010) in the period 2013-2020, *holding the RES-E mix the same*. The corresponding reduction would further increase over the period 2013-2035 by 0.5 billion euro to a level of 0.7 billion euro. Hence, when not allowing for diverging mixes the results of a shift to FIT would slightly improve. Major underlying factors are the unit cost reductions for some technologies dominating the higher balancing cost and regulation cost when adopting FIT. *When allowing for the projected divergence in the RES-E mix*, especially in the longer term, the picture clearly turns out to be negative for the FIT scenario. One again, we would like to repeat that the external costs of the mandatory passing on of business risks to other market players have not been fully internalised in our quantitative analysis. Hence, our quantitative results tend to present a somewhat too rosy picture of a shift to FIT.

Table 4.4 *Net benefits from a Dutch socio-economic perspective of a shift in year 2014 from the prevailing SDE support scheme to a German-like feed-in tariff support scheme*

		Net present value in 2010 [billion $€_{2010}$]					
Period			2013 - 2020			2013-2035	
Discount rate		0 %/a	2.5 %/a	5 %/a	0 %/a	2.5 %/a	5 %/a
Alt I	FIT: same RES-E mix	0.2	0.2	0.2	0.9	0.7	0.5
Alt I	FIT: allowing for changes In the RES-e mix	0.0	0.0	0.0	-1.4	-0.8	-0.5

4.5 Distributional effects of a shift to Alternative I

The government budget

The baseline envisages a change in the financing base for SDE payments to RES-E operators of RES-E installations commissioned in 2013 or later. These payments will be made by AgentschapNL, whilst TenneT might also be involved as last-resort collector of the SDE surcharges mandated on non-privileged end-users. As for Alternative I, TenneT (like the TSOs in Germany since the introduction of the *AusgleichV* regulations) is assumed to administer the FIT fund for payments of feed-in tariffs to eligible RES-E operators, to be replenished by contributions from non-privileged end-users through a FIT surcharge on their energy bills. Hence, apart from the relatively limited cost to the public sector for introducing a German-like feed-in tariff system, the shift to such a support scheme is budget-neutral.

TenneT

In the Alternative I scenario TenneT will be charged with a new responsibility, i.e. to administer a FIT fund with inflows from FIT surcharges on the bill of non-privileged end-users and outflows of FIT payments to eligible RES generators. As such, expansion of TenneT's activities portfolio on the basis of funding by third parties will be good news for TenneT. Yet the first experience gained by German TSOs with this task since 1 January 2010 points into the direction of unforeseen substantial own pre-financing requirements because of downside planning errors regarding prospective FIT payments at the time of fixing ex ante (15 October of the previous year) the FIT surcharge in €ct/kWh of demand by non-privileged end-users. Evidently upside planning errors are possible as well but uncertainty regarding possible pre-financing needs raises the business risk profile of TenneT. On balance, the distributional effects for TenneT would seem ambivalent.

RES-E generators
The Alternative I regime has a number of business advantages for RES-E generators over and above non-RES-E competitors. These include a stable and profitable preferential price with no demand-side volume risk because of the open-end character of the FIT regime, complete shielding against balancing cost risk, commodity price risk, and demand-side commodity volume risk, priority injection of power in the public grid also in case of local network constraints, and non-accountability for the costs made by TenneT in those cases of system redispatch, which are occasioned by RES-E power injections in congested networks. Not surprisingly, RES-E generators tend to strongly lobby in favour of such regulatory regimes. The Alternative I regime is clearly more favourable than other support schemes for these stakeholders in terms of investor's security. The mandated business advantages work out most favourably for small-scale RES-E technology categories. Operators of small-scale RES-E plants highly favour the shifting of business risks to other market players, as they are less capable in terms of specialised manpower to effectively manage such risks.

The baseline SDE support scheme makes due allowance for internalisation of the cost-increasing nature of assuming a number of business risks by the RES-E plant operators themselves. Yet small RES-E generators are forced to pass on balancing responsibility to large energy companies through Power Purchase agreements. The power price for the transfer of balancing responsibility might significantly overstate the real balancing cost concerned to the company contractually buying the power from the small RES-E generators concerned. Hence, particularly small RES-E generators profit from 'infant industry' protection through a FIT support scheme.

Moreover, it cannot be excluded that FIT tariffs and FIP (SDE) premiums alike may contain a significant regulatory rent element as a result of asymmetric information problems in setting these rates. For example, it is plausible that over the last few years German consumers have had to transfer massive regulatory rent cash flows to the PV generation supply chain originating from China. This is evidenced by the recent fast penetration of China-made PV modules in Germany in spite of a series of large reductions in feed-in tariffs (Frondel *et al*, 2010).

Non-RES-E generators
The projected base load power prices and Non-RES-E volumes under the Alternative I and the base load scenario are roughly comparable for the period 2012-2020. This suggests by and large neutral distributive effects for these stakeholders. In our models no quantitative allowance is made for the implications of German-like priority regulation apart from the balancing costs, which will ultimately be borne by the (non-privileged) final electricity users. Yet non-RES-E generators will be at least partly affected by the other cost shifts, associated with unconditional priority access for RES-E generators.

Suppliers
Our projections indicate that, after some years, a higher support cost burden for (non-privileged) end users will be the implication of adopting feed-in tariffs. To the extent that this will not materially impact on final power demand, distributional effects on suppliers will be neutral.

Electricity end-users
Our quantitative projections and qualitative analysis of the German EEG support system indicate that especially in the longer term a higher support cost burden for (non-privileged) end users will result from adopting German-like feed-in tariffs. Depending on the design details, large power consumers might be exempted from this adverse distributional impact.[25]

[25] In Germany some 500-600 large power users are largely exempted; they pay an *EEG-Umlage* of € 0.50 / MWh. This compares to an *EEG-Umlage* of € 35.3 / MWh in year 2011 for unprivileged power customers. In 2009 'privileged' and unprivileged customers consumed a volume of 65 TWh and 499 TWh respectively (See appendix B for more information).

4.6 Concluding observations

The quantitative results and the complementary qualitative analysis of differential RES-E trends in Germany indicate that a shift from the baseline scenario to a FIT scenario:

- Has negative social welfare implications for the Netherlands, mainly in the long term.
- Will increase the hurdles towards smooth integration of intermittent renewables and the introduction of effective smart grid concepts.
- Will strategically set back the Netherlands in capitalising on opportunities for (bottom-up) harmonisation. We will address this issue in Chapter 6.

We refer to statements made by the German government, e.g. in the recent important *Energiekonzept* document, stressing the need for reform of the current EEG support system to improve market integrating of RES-E (see Section 4.2.1). Should the optional feed-in premium proposal - also referred to in the *Energiekonzept* - be adopted indeed, then the German support system is due to evolve to a major extent towards the current support system in the Netherlands.

5. The national hybrid RQS scenario

5.1 Introduction

This chapter describes and analyses Alternative II, i.e. a national Hybrid RQS (RQS-NL) system for the Netherlands. A cost-benefit analysis is conducted of this alternative Dutch RES-E support scheme compared to the baseline scenario, which was explained in Chapter 3.

Section 5.2 introduces the design of the Alternative II scenario. It starts with a description of distinct key features of an certificates-based RQS and how it is presumed to be integrated into the current SDE and then it discusses some main scenario assumptions for Alternative II. The modelling of the RQS certificates market is explained in Appendix A.1. Section 5.3 gives an overview of projected trends for the RES-E sector under the RQS-NL regime. Results of cost-benefit analysis of Alternative II against the baseline scenario from the perspective of Dutch society are explained in Section 5.4. Section 5.5 considers major distributional effects for distinct stakeholder categories. Section 5.6 winds up this chapter with concluding observations.

5.2 On the design of Alternative II: the national hybrid RQS scenario

5.2.1 Background to Alternative II

The concept of a hybrid RQS - feed-in premium support scheme was introduced at the meetings of a CEPS-ECN Task Force on the possible harmonisation of RES-E support (Jansen *et al.*, 2005). Such a prototype scheme may well serve as a possible model for eventual EU-wide harmonisation of national RES-E support schemes. It marries a technology-neutral certificates-based approach with a technology-specific and - subject to consultations between participating countries - country-specific production subsidy approach.

The Dutch SDE feed-in premiums regime boasts some attractive features (see also Section 3.2.1). It sets an *ex ante* subsidy base rate before the commissioning year of an eligible RES-E installation, i.e. an allowable technology-specific cost of electricity level, based on a projected long-term electricity price level. The *ex post* subsidy rate for a certain operational year is determined in the next year: mainly by calculating the difference between the *ex ante* subsidy base rate and the average hourly base load electricity price during the operational year concerned. This way, in principle[26] no regulatory rent is being made (c.q. a regulatory loss incurred) when after the date of commissioning the electricity price increases more than projected (c.q. increases less than expected or even diminishes). Furthermore, the SDE scheme has an additional control instrument to curtail the SDE scheme costs through annual technology-specific budget allocations. For most SDE technology categories the budget allocations are assigned to project developers on a first-come-first-served basis. The other side of the coin of this control instrument feature is that it can give rise to stop-go subsidisation policies. Moreover, another key disadvantage of the Dutch SDE scheme for project developers and their financiers is that the downside risk of a fall in electricity prices is covered for only a certain, limited extent.

The main attractive feature of a national hybrid RQS-SDE scheme for project developers is that the downside risk of a strong fall in electricity prices is almost completely made up for by the negative correlation between the electricity price and the RQS certificate price. A disadvantage of certificates based stimulation systems in general is the potential volatility in the certificate price. Yet if the annual average realised RQS certificate price is included in the determination of the *ex post* SDE subsidy rate, the volatility of total cash flows resulting from commodity plus

[26] Disregarding the asymmetric information problem in setting appropriate subsidy base rates.

RQS certificate sales as well as the possible amount of windfall profits can both be (strongly) mitigated. This goes especially for high-cost RES-E technology categories in need of supplementary SDE support, whereas for categories close to commercial maturity this does not apply. *Therefore, it is of great importance that the support by way of the certificate price will not significantly exceed the cost gap of the cheapest eligible large RES-E technology category.*

This implies that the design of the RQS certificate market is of major importance for its functioning. Ideally, price volatility is moderate within a pre-set ideal bandwidth. The regime for eligible RES-E categories with low capital intensity such as biomass co-firing warrants special attention. Another aspect of major concern is the prevention of market power exercise by integrated suppliers holding RES-E generation assets. Diversity in the portfolio of eligible RES-E installations and owners /operators, in terms of both technology categories and production scale, would seem to be a prime feature of the supply side containing market power. Diversity of certificates-eligible operators is poised to foster competition, including inter-technology competition. The SDE support component fosters a level playing field between generators from different RES-E technology categories.

The level of ambition of the RQS target in relation to perceptions by market participants on the future rate of implementation of new RES-E production capacity over the medium to long term time horizon determines scarcity levels in the RQS certificate market. One the one hand, the government controls the demand side through setting the RQS period and the evolution of the target level. On the other hand, the government influences the supply side through streamlining permitting procedures and manipulating key parameters of the supplementary SDE regulation. Key parameters are fixing SDE base rate levels and SDE annual technology-specific budget allocations. Price volatility can be reduced *inter alia* by allowing for banking. For example, in the Swedish RQS there are no time restrictions to the period of RQS certificate validity.

One major supply-side issue needs to be emphasised. For a well-functioning national[27] RQS certificate market it is of key importance that evolution of new RES-E investment levels do not seriously fall behind anticipated levels of new RES-E investments. Otherwise strong upward pressures on the RQS certificate price may result. In turn, this may lead to mounting windfall profits. Hence, it is of the utmost importance that the public sector periodically (e.g. annually) monitors the realisation of RES-E capacity expansions, smooth implementation of permitting issues and other possible investment bottlenecks. Should major problems arise in the implementation of permitting issues at lower government levels (municipality or provincial levels), quick and appropriate top-down action at central government level is warranted to solve such issues. *Hence, a possible shift to a national hybrid RQS warrants adequate authority to the central government to make the proper interventions to streamline lingering permitting procedures, when needed.*

5.2.2 Main assumptions underpinning the Alternative II scenario

Regarding the Dutch hybrid RQS-SDE market design, assumed main design features include the following ones:

- The RQS certificate eligibility period for eligible RES-E installations as from the installation's commissioning date is 12 years for biomass installations and 15 years for other installations. In principle, depending on biomass input prices, the eligibility period for co-firing is unlimited, as the cost gap refers to potentially expensive biomass fuel costs rather than the incremental capital costs which are projected to be recovered in a certain period.
- Installations using eligible technology are only eligible as from vintage year 2012. This way, the RQS certificate market is kick-started to some extent by installations commissioned in 2012 and 2013.

[27] In the case of a joint RQS certificate market with other member states this holds to a much lesser extent as an expanded market will be deeper. Consequently, price volatility and the potential for market power will be less.

- In principle, for eligible installations one MWh of officially measured MWh production entitles to the issuance of one RQS certificate.
- Yet in order to mitigate potential windfall profit problems, for low-capital, high recurrent-cost options such as biomass co-firing, the option might be introduced in the RQS certificate market design to require per RQS certificate issued a production volume higher than 1 MWh of renewable generation. This is the only market design case, where it is assumed that 'technology banding' might be introduced as an option.[28]
- No restrictions are imposed on the period of validity of RQS certificates, which implies unlimited banking possibilities. This reduces RQS certificate price volatility and renders exercise of market power more complex and risky.
- Promising RES-E categories with a cost gap higher than the pre-set target average RQS certificate price, say, 3 €/MWh qualify for SDE at a level of the subsidy base rate minus the annual average base load power price minus the annual average RQS certificate price.
- In line with the prevailing SDE regulation, the *ex ante* target RQS certificate price and 80% of the projected long-term base load power price will be used to determine the level of advanced SDE payment at the time of RES-E production.

The Alternative II support scheme results in broadly slightly lower generation cost per MWh per technology: the commercial risk profile for project developers (and their financiers) of notably high-cost RES-E technology improves somewhat, compared to the baseline scenario. This relates to the feature of the hybrid RQS-SDE system that the downward risk of plunging electricity prices with regard to the combined cash flows from commodity and RQS certificate sales and SDE subsidy revenues is substantially less than in the baseline (SDE only) scenario. The projected generation costs per RES-E technology under Alternative II have been explained in Section 3.4.

Just like under the baseline scenario, under the Alternative II scenario the *balancing cost* are fully internalised. Operators of RES-E installations, or third parties willing to absorb the pertinent risk within a contractual relationship with the former operators, are fully balancing responsible.

We will assume that the differential cost of RES-E under Alternative II is equal to the sum of the proceeds of RQS certificates issued on the behalf of certificate-eligible operators and revenues from SDE payments to these operators. Presuming a proper market design, no allowance is made for windfall profits. Given the later assumption, the additional cost projections can be interpreted to denote maximum differential cost projections from a social welfare point of view.

Replacing a prevailing RES-E stimulation scheme by an alternative stimulation scheme implies incremental *regulation costs* to electricity system stakeholders. We will assume one-off overnight 'investment cost' as per ultimo 2013 for the public sector in terms of preparations, consultations, outreach, and implementation of Alternative II scheme to the amount of € 15 million. Given the relatively strong need for preparatory market consultations and for knowledge outreach to the market, the assumed one-off public investment costs have been set at a € 5 million higher level than in the case of Alternative I. Regarding the recurrent cost for the public sector, we will assume that the costs for outreach, consultations, and supervision amount to € 0.5 million per year.

[28] This option should only be used with prudent restraint under certain quite well-specified and quite well-identifiable market conditions to mitigate windfall profits: e.g. when the biomass price would fall, the coal price would rise or the carbon price would rise or a combination of these factors to such an extent that the cost gap would fall below, ***e.g***., 1.5 €/MWh or, ***e.g.***, 75% of the cost gap of the option with next lowest cost gap. Also graduation rules should be introduced, withdrawing the eligibility of RES-E technology categories to RQS certificate market support when the cost gap would fall below, say, 40% of the average RQS certificate price of the previous accounting year or below, ***e.g***., 0.8 €/MWh or both.

For TSO TenneT, and more specifically its subsidiary CertiQ, we will assume that the office cost for launching and maintaining the RQS certificate tracking system will entail one-off over-night ‘investment cost’ as per ultimo 2013 of € 1 million in tracking system software and € 0.5 million of incremental operating cost per year. This compares to total operating cost for CertiQ of approximately € 2 millions in accounting year 2009. A lot of synergy can be realised with CertiQ’s current operations, e.g. the ones related to managing the Guarantees of Origin accounting system. In launching and operating the certificate tracking system, the CertiQ organisation can realise major synergy benefits with existing certification activities. Operators of RES-E installations and suppliers or designated traders on their behalf have to operate RQS certificate trading desks. We assume that € 1 million per year will cover these regulation cost. Note that RQS certificate the major part of the transaction costs are borne by CertiQ. Payments to CertiQ for services provided can be considered as distributional transfer payments from a social welfare perspective.

5.3 Projected RES-E trends under Alternative II: RQS-NL

5.3.1 Production by RES-E technologies

Table 5.1 indicates the total RES-E production, differentiated by technology, for the period 2012-2020 for the case in which the mix is the same as the baseline scenario and for the case in which the mix is different. Graphically the same results are shown in Figure 3.4 (same mix) and Figure 5.1 (different mix).

Table 5.1 *Total RES-E production for the period 2012-2020*

[TWh]	2012	2013	2014	2015	2016	2017	2018	2019	2020
Baseline scenario									
Biomass co-firing	5.2	6.8	7.7	8.2	8.8	8.7	8.3	8.9	9.3
Biomass stand-alone	2.4	2.5	2.5	2.7	3.1	3.3	2.8	3.4	4.2
Biomass waste incineration	1.2	1.2	1.2	1.2	1.3	1.4	1.4	1.5	1.6
Landfill gas	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Wind onshore	5.8	6.7	6.6	6.5	8.0	9.5	10.9	12.2	13.1
Wind offshore	0.8	0.8	4.2	4.2	4.2	7.1	10.0	13.0	16.0
Solar PV	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.4
Hydro power	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.6	0.7
Total	16	18	23	23	26	30	34	40	45
RES-E %	13%	15%	18%	19%	21%	24%	27%	31%	35%
RQS-NL scenario (hybrid)									
Biomass co-firing	5.2	6.8	7.7	8.2	9.1	9.3	9.1	10.0	10.8
Biomass stand-alone	2.4	2.5	2.5	2.6	2.7	2.7	2.0	2.4	2.8
Biomass waste incineration	1.2	1.2	1.2	1.2	1.3	1.4	1.4	1.5	1.6
Landfill gas	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Wind onshore	5.8	6.7	6.6	6.5	8.0	9.5	10.9	12.2	13.1
Wind offshore	0.8	0.8	4.2	4.2	4.2	7.1	10.0	13.0	16.0
Solar PV	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.4
Hydro power	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.6	0.7
Total	16	18	23	23	26	29	34	40	45
RES-E %	13%	15%	18%	19%	21%	23%	26%	31%	35%

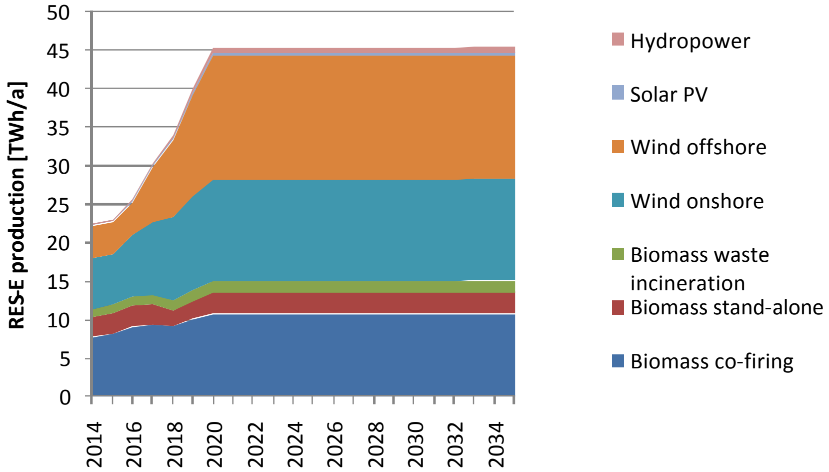

Figure 5.1 *RES-E production [TWh/a] for the RQS-SDE scenario*

It has been projected that large-scale utility-suitable options will be favoured by Alternative II, as this option leaves much more scope for utilities for cost-reducing upscaling, compared to the SDE system. The SDE support system is often characterised by different scale-dependent sub-categories of a specific technology with lower premiums for high-scale sub-categories. Alternative II pays out one RQS certificate to eligible technologies for each MWh fed into the grid. For biomass co-firing operators who are not eligible for additional SDE support, the for this technology scale-independent RQS certificate support is very attractive. Conversely, in a hybrid RQS system, small-scale RES-E operators are exposed to additional risks of the certificates market in comparison with the baseline. Therefore, we have projected a less favourable RES-E evolution for (small-scale, quite expensive) biomass stand-alone as compared to the baseline.

5.4 Cost-benefit analysis of Alternative 2

5.4.1 General overview

The annual cash flows of (positive or negative) net benefits from a shift per 2014 from an intensified SDE support scheme to a national hybrid Renewable Quota System (RQS-NL) support scheme are shown in Table 5.2. The table shows projected cash flows assuming an RES-E mix evolution that is exactly the same as in the baseline in italics.

Table 5.2 *Shift to Alternative II: RQS-NL with same RES-E evolution as in the baseline - Annual incremental net benefits*

[million €$_{2010}$]	2012	2013	2014	2015	2016	2017	2018	2019
Savings on differential RES-E costs			217	225	252	238	213	190
Savings on imbalance costs wind power			0	0	0	0	0	0
Extra regulation costs public sector		-15	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
Extra regulation costs TSO		-1	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
Extra regulation costs suppliers/generators	-1	-1	-1	-1	-1	-1		
Total	**0**	**-16**	**215**	**223**	**250**	**236**	**211**	**188**
Net benefits without RES-E mix chance	*0*	*-16*	*215*	*208*	*214*	*188*	*151*	*114*
	2020	2021	2022	2023	2024	2025	2026	2027
Savings on differential RES-E costs	188	163	134	98	92	133	106	96
Savings on imbalance costs wind power	0	0	0	0	0	0	0	0
Extra regulation costs public sector	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
Extra regulation costs TSO	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
Extra regulation costs suppliers/generators	-1	-1	-1	-1	-1	-1	-1	-1
Total	**186**	**161**	**132**	**96**	**90**	**131**	**104**	**94**
Net benefits without RES-E mix chance	*81*	*74*	*60*	*37*	*36*	*71*	*48*	*27*
	2028	2029	2030	2031	2032	2033	2034	2035
Savings on differential RES-E costs	106	-5	-5	2	-49	-110	-147	-193
Savings on imbalance costs wind power	0	0	0	0	0	0	0	0
Extra regulation costs public sector	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
Extra regulation costs TSO	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5	-0.5
Extra regulation costs suppliers/generators	-1	-1	-1	-1	-1	-1	-1	-1
Total	**104**	**-7**	**-7**	**0**	**-51**	**-112**	**-149**	**-195**
Net benefits without RES-E mix chance	*23*	*-51*	*-44*	*-47*	*-97*	*-130*	*-137*	*-154*

For each cost item, the amounts in Table 5.2 show the projected annual cost savings or cost increases for the alternative support scheme considered, compared to the baseline (SDE) support scheme. *Positive figures* indicate *lower costs* for the alternative support scheme than the corresponding baseline cost, whereas *negative figures* indicate *higher costs* for the alternative support scheme relative to the baseline. In the next sections we will briefly set out the projection results. The summarised results for the case of projected divergence in RES-E evolution are presented in Section 5.4.4 below.

5.4.2 Net benefits: generation costs

Differential cash flows between the Alternative II scenario and the baseline regarding the cash flow category *savings on differential RES-E costs* account for the lion's share of the net benefits of a shift towards a national hybrid Renewable Quota System. As explained in Section 3.6, after 2020 RES-E volumes overall and per technology category have been held more or less[29] constant at year 2020 levels.

[29] See previous footnote.

A typical undercurrent in the overall 2013-2035 analysis period is the slightly lower generation cost per RES-E technology for Alternative II as compared to the baseline. This was explained in Section 3.4. In principle, the unit generation cost under Alternative I is indicated by the sum of the commodity price, the RQS certificate price and, if applicable, the SDE subsidy per unit of electricity.

Generators benefitting from the RQS support system under Alternative II scenario have their own responsibility to market the electricity they produce and to notify TSO TenneT day ahead of their production schedule per settlement period units of (in the Netherlands) 15 minutes. In principle, they can pass on these responsibilities by entering into a purchasing power agreement (PPA) with a third balancing-responsible party. Typically, parties on the power-receiving end of such PPAs are large power suppliers, often with own generating assets. The latter parties are well-placed to capitalise on the portfolio effect with regard to scheduling errors in the scheduled injections of generation installations and absorptions from the public grid by loads under their respective responsibility. Independent RES-E generators entering in a PPA will have to accept discounts for balancing and commodity market risk with respect to the agreed benchmark forward power price defined in the typically undisclosed bilateral agreement concerned. Hence, in principle balancing and marketing costs are internalised under the Alternative II scenario. This stands in stark contrast to the Alternative I support scheme.

5.4.3 Other net benefit categories

Replacing the prevailing RES-E support scheme by an alternative support scheme implies incremental *regulation costs* to electricity system stakeholders. As explained in Section 5.2.2, we have assumed one-off overnight 'investment cost' as per ultimo 2013 for the public sector in terms of preparations, consultations, outreach, and implementation of Alternative II scheme to the amount of € 15 million. The recurrent costs for the public sector have been set at € 0.5 million per year.

For TSO TenneT one-off overnight investment costs as per ultimo 2013 of € 1 million were imputed and € 0.5 million incremental operating cost per year. For other RQS certificate market participants administrative costs totalling € 1 million per year have been assumed.

5.4.4 Net present value of annual net benefit cash flows

To bring out the more near-term impact of a change from the baseline scenario to the Alternative II scenario, we calculated the projected NPV of differential cash-flows for the period 2013-2020. More structural trends can be observed from the projected NPV for the period 2013-2035 and its difference with the one for 2013-2020. The resulting NPV values are shown in Table 5.3. Applying the recommended 2.5% discount rate, our projections indicate that a shift from the baseline support scheme to a national hybrid Renewable Quota System support scheme would reduce the costs of RES-E support to the Dutch society by 1.0 billion euro in the period 2013-2020 (at prices of 2010). This holds both when the RES-E mix is assumed to evolve exactly the same as the baseline and for Alternative II when allowing for the projected divergence in the RES-E mix evolution compared to the baseline.

During the period 2021-2035 the present value of projected aggregate net benefits are indicated to decline somewhat. This holds especially when allowing for the projected divergence in the RES-E mix. In the latter case the NPV over the annual cash flows during 2013-2020 is with € 0.9 billion slightly less. A major underlying factor is that all annual RES-E production volumes after 2020 have been assumed to remain at the corresponding levels for year 2020. This means that after 2020 no further market-based optimisation of the RES-E mix is presumed to take place. In practice, a market-based support system such as the hybrid RQS stimulates market players to adjust market behaviour to divergent cost (reduction) developments among the different RES-E technologies. If a scenario of rising policy ambitions, translating into rising RES-E volumes, were to obtain the overall NPV for the period 2012-2035 this would lead to higher values than the ones shown in Table 5.3. This relates primarily to the innate tendency in the RQS scenario to stimulate production volumes of RES-E technologies with a low financial gap stronger than the ones with a high financial gap.

Reasons for the large increases in differential RES-E costs compared to the baseline in the final years of the period 2021-2035 are the following. The RES-E generation costs decline in time for wind energy and solar PV whereas the generation costs from biomass installations are not assumed to decline in time. Although the generation costs of wind energy decline in time, the imbalance costs of wind power are increasing in time. The imbalance costs become an increasingly dominant cost factor in time. Another obscuring factor in the evolution of the benefits is the replacement investments for old RES-E installations (as the total RES-E generation is modelled to remain constant post 2020). For example, wind projects are expected to produce electricity up to five years after the subsidy has ended, due to their low marginal production costs. In the period 2025-2030, some wind projects' SDE grants will expire, although production has not ceased. Especially in the period 2030-2035, several offshore wind farms are modelled to be replaced. The replacement investments that are necessary after 2030 depend on the RES-E mix at that time. These effects also show in Alternative I. Furthermore, in case of high CO_2 prices in the later years, some biomass co-firing options can experience larger windfall profits, unless this possibility is adequately addressed by proper regulation. Such profits can be mitigated by several policy design options such as banding (i.e. giving less certificates per produced RES-E than for other RES-E categories), those design options have been identified but not been considered in detail in this study.

An overall conclusion on the basis of results presented in Table 5.3 is that - especially in the period 2013-2020 and somewhat less pronounced in the period thereafter up to and including year 2035 - Alternative II shows fairly modest and therefore less robust positive welfare impacts, compared to the baseline. For example, a net present value over a period of 22 years (2013-2035) of 1.6 billion euros of year 2010 averages out per year to an amount of 73 million euros of year 2010 per annum.

Table 5.3 *Net benefits from a Dutch socio-economic perspective of a shift in year 2014 from the prevailing SDE support scheme to a national hybrid Renewable Quota System support scheme*

		Net present value in 2010 [$€_{2010}$ billion]					
Period			2013 - 2020			2013-2035	
Discount rate		0 %/a	2.5 %/a	5 %/a	0 %/a	2.5 %/a	5 %/a
Alt II	RQS-NL: same RES-E mix	1.2	1.0	0.8	0.9	0.9	0.8
Alt II	RQS-NL: allowing for changes in the RES-E mix	1.5	1.3	1.0	1.9	1.6	1.4

5.5 Distributional effects of a shift to Alternative II

The government budget

The baseline envisages a change in the financing base for SDE payments to RES-E operators of RES-E installations commissioned in 2013 or later. These payments will be made by Agentschap NL, whilst TenneT might also be involved as last-resort collector of the SDE surcharges to be imposed by force of law on non-privileged end-users. Moreover, Alternative II implies the introduction of a certificates-endorsed demand-side RQS. The compliance burden rests on the demand side, i.e. ultimately the final electricity users. Hence, except for the relatively limited cost to the public sector for introducing and supervising the demand-side RQS, the shift to such a support scheme is budget-neutral.

TenneT

In the Alternative II scenario TenneT's daughter company CertiQ will be charged with a new responsibility, i.e. to administer the RQS certificate tracking system on the basis of third party payments of annual membership and volume-dependent transaction fees. As this additional activity means more business for CertiQ, the distributional effect for TenneT is positive. The financial importance for TenneT at large, in contrast to CertiQ in particular, is rather limited.

RES-E generators

The Alternative II regime is slightly more advantageous to RES-E generators benefitting from RQS certificate revenues as well as supplementary SDE than the baseline regime, as the downside risk to these RES-E generators of a steep fall in the electricity price will be almost completely mitigated by RQS certificate revenues. Conversely, the risk profile for RES-E generators changing from an SDE only support regime to just an RQS certificate only regime deteriorates, depending on the experience to be gained regarding the robustness of the RQS certificate market (notably, regarding the volatility of the RQS certificate price). To the extent that biomass co-firing will be eligible for the (properly designed) renewable quota system, these generators stand to gain importantly. Proper regulation should include instruments to mitigate this special problem. In concluding chapter 7 we have identified but not elaborated[30] dedicated regulation to manage this risk. Depending on the volume performance of co-firing generators, there will be some leeway to reduce the annual budget ceilings for high-cost RES-E generators. Hence the latter category stands to lose to some extent.

Non-RES-E generators

The projected base load power prices and non-RES-E volumes under the Alternative II and the base load scenario are roughly comparable for the period 2012-2020. This suggests by and large neutral distributional effects for these stakeholders. Renewable co-firing generators stand to gain to a certain extent.[31] The size of the latter gains depends notably on the uncertain evolution of the biomass feedstock price, the coal price and the carbon price and proper dedicated regulation.

Suppliers

Our projections indicate that a somewhat lower support cost burden for (non-privileged) end users will be the implication of adopting the Alternative II support scheme. To the extent that this will not materially impact on final power demand, distributional effects on suppliers will be neutral.

Electricity end-users

Our projections indicate that upon adoption of Alternative II the support cost burden for (non-privileged) end users will initially decrease markedly compared to the baseline while after 2020 part of this decrease will largely vanish. We have noted that a major underlying factor is that RES-E volumes after 2020 have been presumed constant, which reduces the inherent capability of the market-based support mechanism considered to optimise the RES-E portfolio into a cost-reducing direction.

A separate design issue is the burden falling on large power consumers. A detailed analysis of this issue is beyond the scope of this study. It would seem that the impact of adopting Alternative II on the international competitiveness merits special consideration and regulatory flexibility regarding future developments on this score. To the extent that large power users are exposed to international competition and world-wide, notably EU-wide, large power users are ex-

---

[30] As this falls beyond the scope of our study.

[31] Disregarding a possible concomitant biomass co-firing obligation measure upon coal-fired power plants. Contingent on the stringency of such a possible measure this would negatively affect profit levels for operating such plants and would put an upward pressure on wholesale power prices as well with negative effects for power users, including electricity-intensive industrial users.

empted from the burden of RES-E support schemes, Dutch large power users would seem to be granted a (partial or complete) waiver as well. The Swedish renewable quota system, where in 2008 41.6 TWh of the 94.0 TWh final power demand participating in the RQS certificate scheme was exempted from target compliance, might well give useful directions as to how to address this issue. Companies using at least 40 MWh / SEK million of company turnover get a partial (at least 50%) or complete waiver (SEA, 2009).

5.6 Concluding observations

On the basis of the quantitative results and the complementary qualitative analysis, the conclusion can be drawn that a shift from the baseline support scheme to a national hybrid support scheme:

- Will have - relatively modest - positive social welfare implications for the Netherlands.
- Might foster innovation towards cost reductions in some large-scale RES-E technologies (see also Section 3.4).
- Will place the Netherlands in a good position to capitalise on opportunities for (bottom-up) harmonisation. *This latter strategic point which has not been included in the quantitative CBA is perhaps the foremost consideration to start a national RQS, patterned to a proper major extent on the Swedish RQS system.* We revert to this issue in Chapter 6.

Some qualifications are in order regarding system design. Good system design is essential to realise the expected net benefits. The RQS certificate supervisory authority and the central government should closely monitor the RQS certificate market and use a range of intervention instruments to foster the RQS certificate price fluctuating within a pre-set publicly announced target bandwidth. Too low prices discourage investments in RES-E technologies solely supported by RQS certificate revenues, whilst too high prices exceeding significantly the projected cost gap of the lowest cost large RES-E technology in need of support by the hybrid RQS may lead to unacceptable windfall profits. Instruments at the disposal of the authorities include[32]:

- A broad diversity of RES-E technologies participating in the RQS.
- System target setting.
- Integrating RQS certificate market considerations in setting SDE subsidy base rates.
- Integrating RQS certificate market considerations in setting technology-specific SDE budget ceilings.
- Allowing the banking of RQS certificates.
- At least initially a minimum RQS certificate price could be guaranteed as was done when introducing the renewable quota system in Sweden.
- The option of raising the quantity of generated RES-E electricity per RQS certificate issued to more than one MWh might be exercised under certain well-specified market conditions. This option should *only* be considered for specific biomass options with high recurrent expenditure including the cost of biomass throughput and low incremental capital costs. The notable technology to be considered for this design feature is biomass co-firing.

Another major issue is the streamlining of permitting procedures. Monitoring and, when needed, interventions by the central government are in order, should undue delays occur at lower government levels. This issue is not only key in achieving very ambitious RES-E sub-targets, but is also of key importance for a well-functioning national RQS certificate market.

[32] See the concluding chapter for additional design options.

6. A joint hybrid RQS support scheme with Sweden

6.1 Introduction

This chapter describes and analyses Alternative III, i.e. a joint hybrid RQS support scheme with Sweden (RQS-SE). A cost-benefit analysis is performed of this third alternative Dutch RES-E stimulation scheme compared to the baseline scenario, which was explained in Chapter 3.

Section 6.2 introduces the design of Alternative III scenario. It starts with a description of distinct key features of an certificates-based RQS and how it is presumed to be integrated into the current SDE and then it discusses some main scenario assumptions for Alternative III. The modelling of the RQS certificates market is explained in Appendix A.1. Section 6.3 gives an overview of projected trends for the RES-E sector under the RQS-SE regime. Results of the cost-benefit analysis of Alternative III against the baseline scenario from the perspective of Dutch society are explained in Section 6.4. Section 6.5 considers major distributional effects for distinct stakeholder categories in both the Netherlands and Sweden. Section 6.6 winds up this chapter with concluding observations.

6.2 On the design of Alternative III: a joint hybrid RQS support scheme with Sweden

6.2.1 Background to Alternative III

Alternative III draws importantly on Alternative II, i.e. a national hybrid RQS-SDE support scheme. Currently, Sweden has a certificate-based RQS support scheme which is increasingly effective in reaching fairly ambitious system targets and at the same time ranks among the most efficient national support schemes in Europe.[33]

At various occasions the Swedish government has stated its wish to engage in an international expansion of its successful, very cost-effective support scheme. In 2004 negotiations started with Norway to embark on a common certificate-based RQS support scheme, which came to an unsuccessful conclusion in 2006. Recently Sweden and Norway reopened negotiations on a common certificates-based support scheme, which is officially scheduled to lead to its launch in the beginning of 2012. This appears ambitious given that Norway still needs to transpose EU RES Directive 2009/28/EC into its national legislation and to further change its legislation in endorsement of the envisaged common SE-NO support scheme. If this joint support scheme is to materialise indeed, this may well be the stepping stone to a broader trend towards bottom-up harmonisation of RES-E support schemes in the EU. Article 11 of Directive 2009/28/EC allows for joint support schemes as one of the so-called co-operation mechanisms defined by this directive. Swedish officials have recently alluded to the possibility to collaborate with ‘a third country’, should the bid to establish a joint SE-NO support scheme flounder.[34]

The key driver towards the establishment of market-based joint support schemes is to achieve higher cost-effectiveness in target compliance by capitalising on the *gains from trade*. Expanding the domain of a well-designed joint support scheme enables reduction of total RES-E generation costs to achieve the sum of the national RES-E targets of the participating countries. This would, e.g., permit to concentrate wind power based generation in western coastal areas,

[33] So far the European Commission in its various communications about RES support schemes has paid remarkably little specific attention to the good performance of the Swedish support scheme. Sweden’s rich RES-E resource endowments certainly play a part but do not tell the whole story.

[34] ‘Sweden-Norway trading scheme could boost investor’s interest’, article in *Platts Renewable Energy Report*, issue 214, October 4, 2010.

biomass-based generation in biomass-resource-rich areas, solar generation technologies in the most southern regions, etc. Many studies indicate that market forces as against government agencies are best placed to localise the application of lowest-cost resources for the lowest-cost RES-E generation technologies in the whole domain within the framework of a joint support scheme. A recent German modelling study indicates an EU-wide cost savings potential for the period 2008-2020 in the order of €$_{2007}$ 100 billions (i.e. some 8 billion euro per year) in achieving 30% RES-E in the EU by way of a harmonised market-based support scheme as compared to a baseline with intensification of the currently existing fragmented national support schemes. The RES-E cost of the baseline scenario for achieving a 30% RES-E share in 2020 would carry a price tag for the period 2008-2020 of €$_{2007}$ 412 billions (Fürsch *et al.*, 2010). Renewable Energy Directive 2009/28/CE precludes expedient top-down harmonisation of national RES-E support schemes. Yet the less favourable conditions of the current EU economy in combination with the fast rising trend in expenditures on RES-E stimulation may well foster a sub-set of EU Member States to explore the opportunities and challenges of enhancing the cost effectiveness of RES target compliance through market-based joint support schemes.[35]

This study investigates the introduction of a flexible hybrid RQS joint support scheme between the Netherlands and another EU Member State. Such a scheme is to allow functional supplementary national RES-E support measures. Such supplementary support measures would have to duly allow for specific national circumstances and be subject to consultations between the participating Member States. For instance, the Netherlands has a quite steep renewable electricity supply curve which necessitates additional technology-specific support to the high-cost RES-E technologies needed to achieve a high share of the Dutch renewables target for 2020 within the country. The SDE (the existing Dutch feed-in premium scheme) is well-suited to meet this need.

In a previous ECN study Sweden has been identified as the best fit for a joint hybrid RQS support scheme with the Netherlands (Jansen, 2010a). Major reasons include:
- The quite diverse portfolios of RES-E resources between Sweden and the Netherlands, making for a large *gains from trade* potential.
- The scope for additional RES-E production in Sweden at relatively moderate cost on top of complying with Sweden's RES target in 2020 as laid down in the Renewable Energy Directive. In contrast, the Netherlands is only to meet its 2020 RES target completely within the country at quite high marginal cost. This further strengthens the potential for win-win trade.
- Realisation of the planned launch of the Swedish-Norwegian joint support scheme would further enhance the economics of a Dutch accession to this certificates-based scheme, assuming a proper integration of the Dutch SDE scheme. The reason is that the Norwegian resource base of qualifying resources is even stronger than Sweden's one on wind power and (new) hydro and more divergent from the Dutch than from the Swedish resource base (Greenstream, 2010; SEA, 2005). E.g. biomass co-firing plays a major role in the Netherlands as against a negligible role in Sweden and Norway, while the opposite is true for (new) hydro in Sweden and notably Norway.

Depending on well-conceived design details, a smooth transition process towards a joint support scheme without large movements of the certificate price upon expansion of the renewable quota system is feasible. Should the Netherlands switch to the Swedish (or for that matter a Nordic) renewable quota system without any supplementary support measures, this is likely to strongly push up the RQS certificate price on account of unbridled Dutch imports of RQS certificates

[35] The fast rise of RES-E technology industries in emerging economies such as China and India, already partly outcompeting their European peers, would seem to further strengthen the case (at least from a socio-economic perspective) to not further put off the transition from 'infant industry' national protection policies and fragmented national markets shielded from competitors from other Member States towards achieving a single, competitive European market for RES-E technologies. Such a quick transition would seem indispensible in achieving - with respect to the world-wide rapidly expanding renewable energy industries − the Lisbon Agenda aimed at reaching a competitive Europe within the global trading space.

originated in Sweden (or Norway). However, a joint SE (- NO) - NL support scheme with a supplementary integrated SDE scheme on the Dutch side provides valuable additional (indirect) market stabilisation instruments apart from the joint support scheme target. In order to prevent a large, unchecked net Dutch import of RQS certificates originated in Sweden (or Norway), the SDE subsidy base rate levels and the technology-category-specific annual budget ceilings should initially be kept at quite attractive levels to boost RES-E investments in the Netherlands. Subsequently, after the joint RQS certificate market has absorbed the Dutch accession successfully, these levels can be gradually revised downward for the most expensive RES-E categories subject to prior technology-specific analysis and policy consultations. Up to certain limits, to be defined in mutual consultation, the hybrid RQS scheme can endorse subsidiarity in technology-specific support in each of the participating countries. Upon further international expansion of the RQS certificate market and further cost reductions in RES-E technologies, the need for supplementary support in countries with steeply rising RES-E supply curves is due to gradually lessen and to cease in the longer term. The reason is that such countries and their relevant private market actors will be able to increasingly rely on the RQS certificate market for achieving the currently national, or possibly later unified European renewables targets, with associated increase in European social welfare.

At least in the beginning, Member States might resist to having to completely relinquish national RES stimulation measures. This may relate to national industrialisation policies targeting perceived national infant industries, 'social cohesion' in peripheral regions, etc. In fact, whilst hybrid features might be necessary for a smooth expansion of the renewable quota system to countries with a poor renewable resource base, they push up the total cost of achieving RES-E goals in the common support scheme domain. Hence, hybrid features might be gradually reduced and eventually phased out when there are consistent general-confidence-boosting signs of a liquid, well-functioning and stable certificate market confirming the robustness of the common support scheme.

6.2.2 Main assumptions underpinning the Alternative III scenario

Generally the same assumptions are assumed to be valid for the common SE-NL RQS certificate market design as the RQS certificate market design in Alternative II (see Section 5.2.2). The only exception is the regulation cost for the public sector. Accession to a common support scheme with Sweden requires additional preparation in terms of negotiations with the Swedish government and the European Commission. Moreover, recurring bilateral consultations are needed. Accordingly, we have assumed one-off overnight 'investment cost' as of 2013 for the public sector in terms of preparations, consultations, outreach, and implementation of the Alternative III scheme to the amount of € 20 million. As for the recurrent cost for the public sector, we have assumed that the cost for outreach, consultations, and supervision amount to € 0.7 million per year. This is € 0.2 million per year more than in Alternative II due to international consultations on RQS review, including national supplementary support measures such as the Dutch SDE regulations.

We note that the important practical benefits of improved RQS certificate market functioning as a result of market domain expansion have not been captured in our modelling exercises. Enhanced market functioning as a result of geographical market expansion stems from (SEA, 2005):

- More market transparency with a stronger drive towards a larger role for central trading platforms.
- Less market concentration.
- Reduced price swings.
- Lower political risks for RES-E project developers.
- Stronger drive towards cost-reducing RES-E market innovations through economies of scale enabled by larger market volumes.

Such benefits become manifest in a rather unforeseeable, random fashion and, for that reason, are indeed quite hard to capture quantitatively in market models.

6.3 Projected RES-E trends under Alternative III: RQS-SE

Alternative III distinguishes itself from the other alternatives in that only Alternative III includes net import of target accounting attributes for the purposes of the new renewable energy directive. Hence, only in Alternative III part of the 35% RES-E share is to be achieved by generation of in the margin cheaper RES-E outside the Netherlands. This is further explained by projected RES-E trends under Alternative III below.

6.3.1 Projected production by RES-E technologies

Table 6.1 indicates the total RES-E production, differentiated by technology, for the period 2012-2020.

Table 6.1 *Total RES-E production [TWh] for the period 2012-2020*

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Baseline scenario									
Biomass co-firing	5.2	6.8	7.7	8.2	8.8	8.7	8.3	8.9	9.3
Biomass stand-alone	2.4	2.5	2.5	2.7	3.1	3.3	2.8	3.4	4.2
Biomass waste incineration	1.2	1.2	1.2	1.2	1.3	1.4	1.4	1.5	1.6
Landfill gas	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Wind onshore	5.8	6.7	6.6	6.5	8.0	9.5	10.9	12.2	13.1
Wind offshore	0.8	0.8	4.2	4.2	4.2	7.1	10.0	13.0	16.0
Solar PV	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.4
Hydro power	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.6	0.7
Total	16	18	23	23	26	30	34	40	45
RES-E %	13%	15%	18%	19%	21%	24%	27%	31%	35%
RQS-SE scenario									
Biomass co-firing	5.2	6.8	7.7	8.2	9.1	9.3	9.1	10.0	10.8
Biomass stand-alone	2.4	2.5	2.5	2.4	2.4	2.2	1.2	1.3	1.4
Biomass waste incineration	1.2	1.2	1.2	1.2	1.3	1.4	1.4	1.5	1.6
Landfill gas	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Wind onshore	5.8	6.7	6.6	6.5	8.0	9.5	10.9	12.2	13.1
Wind offshore	0.8	0.8	4.2	4.2	4.2	7.1	7.4	7.4	7.4
Solar PV	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.4	0.4
Hydro power	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.6	0.7
Total (excl. import)	16	18	23	23	25	30	31	33	35
Domestic RES-E %	13%	15%	18%	19%	20%	24%	24%	26%	27%

Compared to the baseline scenario, more biomass is co-fired. The introduction of a hybrid RQS/SDE system limits the development of offshore wind, which is one of the more expensive types of RES-E production and is up to a certain extent outcompeted by import of RQS certificates from Sweden, see Figure 6.1. The same goes for the expensive small-scale technology biomass stand-alone.

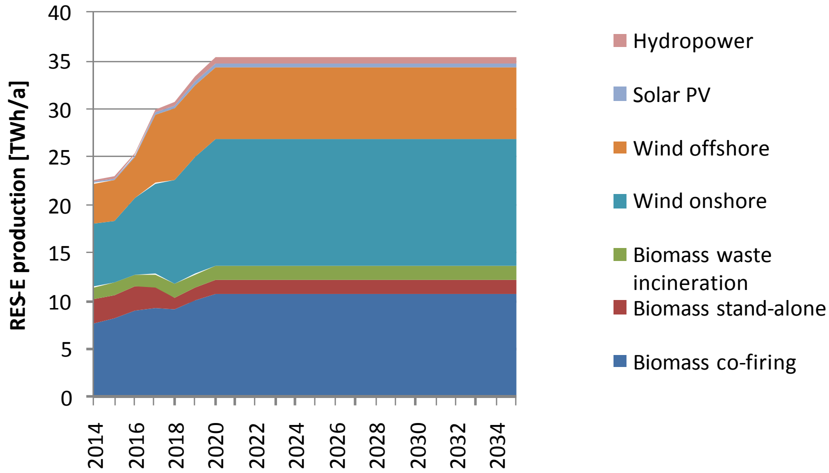

Figure 6.1 *RES-E production [GWh] for the RQS-SDE scenario*

6.4 Cost-benefit analysis of Alternative III

6.4.1 General overview

The annual cash flows of (positive or negative) net benefits to the Dutch economy from a shift per beginning of year 2014 from an intensified SDE support scheme to a joint hybrid Renewable Quota System support scheme between Sweden and the Netherlands (RQS-SE) are shown in Table 6.6. For each cost item the amounts shown result from the projected differential annual cost of the alternative support scheme considered as compared to the baseline (SDE) support scheme. Positive (negative) figures indicate lower (higher) costs for the alternative support scheme than the corresponding baseline cost. In the next sections we will further examine the CBA results.

Table 6.2 *Shift to Alternative III: RQS SE - Annual incremental net benefits to the Netherlands*

[€$_{2010}$ million)]	2012	2013	2014	2015	2016	2017	2018	2019
Savings on differential RES-E costs			217	234	275	281	459	633
Savings on imbalance costs wind power			0	0	0	0	6	14
Extra regulation costs public sector		-20	-0,7	-0,7	-0,7	-0,7	-0,7	-0,7
Extra regulation costs certifying body		-1	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5
Extra regulation costs suppliers/generators			-1	-1	-1	-1	-1	-1
Total	**0**	**-21**	**214**	**232**	**272**	**278**	**464**	**645**
	2020	2021	2022	2023	2024	2025	2026	2027
Savings on differential RES-E costs	805	757	698	629	612	629	568	522
Savings on imbalance costs wind power	21	21	21	21	21	21	21	21
Extra regulation costs public sector	-0,7	-0,7	-0,7	-0,7	-0,7	-0,7	-0,7	-0,7
Extra regulation costs certifying body	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5
Extra regulation costs suppliers/generators	-1	-1	-1	-1	-1	-1	-1	-1
Total	**824**	**776**	**718**	**648**	**631**	**648**	**587**	**541**
	2028	2029	2030	2031	2032	2033	2034	2035
Savings on differential RES-E costs	497	329	280	275	198	55	-50	-153
Savings on imbalance costs wind power	21	21	21	21	21	21	21	21
Extra regulation costs public sector	-0,7	-0,7	-0,7	-0,7	-0,7	-0,7	-0,7	-0,7
Extra regulation costs certifying body	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5	-0,5
Extra regulation costs suppliers/generators	-1	-1	-1	-1	-1	-1	-1	-1
Total	**516**	**348**	**299**	**294**	**217**	**74**	**-30**	**-134**

6.4.2 Net benefits: generation costs

Differential cash flows between the Alternative III scenario and the baseline regarding the cash flow category *savings on differential RES-E costs* account for the lion's share of the net benefits to the Dutch economy of a shift towards a joint hybrid Renewable Quota System support scheme with Sweden.

One underlying factor accounting for positive or negative values for an alternative scenario regarding generation costs concerns diverging trends in the RES-E production portfolio for the distinct support schemes. Alternative III is in several respects comparable to Alternative II, as in both cases a hybrid RQS/SDE system is the support scheme. However, in Alternative III high additional savings can be realised through (partial) substitution of the more expensive inlands RES-E generation options by import of RQS certificates originated in Sweden. Part of the target accounting units generated by extra renewable electricity production in Sweden over and above levels needed to achieve the Swedish RES targets becomes available for the Dutch renewable electricity target through trade in certificates.

The implicit assumption here is that the bilateral government-to-government agreement, upon which the joint support scheme is based, specifies that an RQS certificate serves two purposes at the same time. An RQS certificate is supposed to serve:

1) As piece of evidence of system compliance for obligated parties to the joint RQS (electricity suppliers and certain electricity end-users).
2) As a target compliance unit at cancellation, i.e. when obligated parties surrender the RQS certificate to the RQS certificate accounting system administrator for compliance with the RQS target.

It is up to governments concerned to agree on a possible additional price for the transfer of target accounting units. *In principle*, from a fair trade point of view, free transfer would be justified. However, not all incremental net costs to the exporting country of generating and evacuating the specific quantity of RES-E to which the RQS certificate corresponds may have been internalised in the sum of the electricity price, the RQS certificate price and the use of (electricity network system) charges paid by the RES-E generator.

In most EU countries generators pay hardly any use of system charges. The network costs of injecting renewable electricity are minimal or even negative at hours when nearby load centres exercise surplus demand that otherwise can only be served by a distanced generation source via the high-voltage transmission network in its absence. Yet especially an intermittent source like wind power typically feeds into the grid in remote, low-demand areas. This usually has to be transported through the transmission grid to far-away load centres. The intermittent character of the generation increases the cost as the investment capital tied up in the network concerned can be utilised less intensively. *In conclusion, to the extent that the prevailing network tariff system of the exporting country does not charge more or less cost-reflective tariffs to generators, including RES-E generators, the external network costs could be included in the price of statistical transfers*[36]. Upon reform of the charging methodology for use of network system by generators in a cost-reflective way, the case for extra payments for statistical transfers in the case of joint support systems would weaken accordingly.

The more expensive Dutch renewable electricity options are stand-alone biomass installations and offshore wind. On the other hand, biomass co-firing and wind onshore are competitive in Alternative III and their deployment is identical to Alternative II.

A second factor accounting for differences in additional generating cost are the slightly lower (Dutch) generation cost for certain RES-E technology for Alternative III as compared to the

[36] Statistical transfers is legal EU lingo introduced by the Renewable Energy Directive 2009/28/CE. It stands for the cross-border transfer of target accounting units.

baseline. This was explained in Section 3.4. In principle, the unit generation costs under Alternative III are indicated by the sum of the commodity price[37], the RQS certificate price and, if applicable, the SDE subsidy per unit of electricity.

Just like under the baseline scenario and under Alternative II, generators in the Alternative III scenario benefitting from the RQS support system have their own responsibility to market the electricity they produce and to notify TSO TenneT day ahead of their production schedule per settlement period units of (in the Netherlands) 15 minutes. Independent RES-E project developers will tend to pass on balancing responsibility to integrated electricity companies to whom they sell their production through power purchase agreements (PPAs). The agreed price, typically based on a convenient benchmark price, will include a discount for the transfer of the balancing risk. Large integrated electricity companies with RES-E generation assets or PPAs with independent RES-E power producers are in a good position to benefit from the portfolio effect of uncorrelated random deviations of actual from scheduled load injections by generation plants and absorptions by customer connections in their total portfolio. Average deviations diverge per RES-E technology with wind power tending to account for the highest deviations per MWh. Hence projected diverging balancing costs between Alternative III and the baseline relate to different RES-E generation mixes.

6.4.3 Other net benefit categories

Replacing the prevailing RES-E stimulation scheme by an alternative stimulation scheme implies incremental *regulation costs* to electricity system stakeholders. As explained in Section 6.2.2. we have assumed one-off overnight 'investment cost' as of 2013 for the public sector in terms of preparations, consultations, outreach, and implementation of Alternative I scheme to the amount of € 20 million. The recurrent costs for the public sector have been put at € 0.7 million per year. For the remainder, regulatory costs have been assumed at the same level as under Alternative II.

6.4.4 Net present value of annual net benefit cash flows

To bring out the more near-term impact of a change from the baseline scenario to the Alternative III scenario, we calculated the projected NPV of differential cash flows for the period 2013-2020. More structural trends can be observed from the projected NPV for the period 2013-2035 and its difference compared to the one for to 2013-2020.

The resulting NPV values are shown in Table 6.3. Applying a 2.5% discount rate, our projections indicate that a shift from the baseline support scheme to a joint hybrid RQS support scheme with Sweden in the period 2013-2020 would reduce the costs of RES-E support to the Dutch society by 2.4 billion euro (of 2010). In the Alternative III scenario the cost reductions for Dutch RES-E market stimulation as measured against the baseline benchmark are set to continue after 2020 reaching an aggregate level of 4.2 billion euro in the period 2021-2035, whilst the projected result for the total analysis period 2012-2035 is 6.6 billion euro saved on RES-E market stimulation. These results are insensitive in nature to the choice of discount rate within the (rather wide) 0-5% per annum interval.

[37] Use of (network) system charges for generators are poised to be factored into their bid prices.

Table 6.3 *Net benefits from a Dutch socio-economic perspective of a shift in year 2014 from the prevailing SDE support scheme to a joint hybrid Renewable Quota System support scheme with Sweden (RQS SE)*

		Net present value in 2010 [$€_{2010}$ billion]					
Period		2013 - 2020			2013-2035		
Discount rate		0 %/a	2.5 %/a	5 %/a	0 %/a	2.5 %/a	5 %/a
Alt III	RQS SE	2.9	2.4	2.0	9.0	6.6	4.9

6.5 Distributional effects of financial impacts of a shift to Alternative III

6.5.1 Effects on Dutch stakeholders

In the Netherlands most distributional impacts of a shift in RES-E support scheme to Alternative III will largely be similar to the ones associated with a shift to Alternative II. Below, the distributional impact per major stakeholder category will be briefly explained.
Table 6.4 presents some projected relevant trends that provide more insight into ‘who will lose and who will gain’.

The government budget
The baseline envisages a change in the financing base for SDE payments to RES-E operators of RES-E installations commissioned in 2013 or later. These payments will be made by AgentschapNL, whilst TenneT might also be involved as last-resort collector of the SDE surcharges to be imposed by force of law on non-privileged end-users. Alternative III moreover implies the introduction of an certificates-endorsed demand-side RQS. The compliance burden rests on the demand side, i.e. ultimately the final electricity users. Hence, apart from the relatively limited cost to the public sector for introducing and supervising the demand-side RQS, the shift to such a support scheme is budget-neutral. The relatively limited cost to the public sector for introducing and supervising the joint demand-side RQS scheme with Sweden will be slightly higher than under the Alternative II scenario due to bilateral governmental consultations between the participating countries in the joint support scheme concerned.

Dutch TSO TenneT
In the Alternative III scenario TenneT’s daughter company CertiQ will be charged with the responsibility, i.e. to administer the Dutch domain of the two-country RQS certificate tracking system on the basis of third party payments of annual membership and volume-dependent transaction fees. This additional activity means more business for CertiQ. As under Alternative II, the distributional effect for TenneT is positive. The financial importance for TenneT at large, in contrast to CertiQ in particular, is rather limited.

RES-E generators
The Alternative III regime will negatively affect high-cost RES-E generators in the joint support ‘bubble’ more strongly than without the international expansion of a national Dutch hybrid RQS scheme. In the RQS-SE scenario, the adversely affected high-cost RES-E generators are virtually exclusively located in the Netherlands. It depends on the disposition of the Dutch government to qualify the high-cost RES-E technology categories concerned as having innovative potential with attendant annual budget ceiling allocations how much the RES-E technology categories concerned are affected. Conversely, our modelling exercises, amongst others based on data kindly provided by the Swedish Energy Agency, suggest that Dutch co-firing generators will be among the marginal ones under the RQS SE scenario. Assuming no additional measures such as a stringent biomass co-firing obligation for coal-fired power plants, this last category of generators is likely to benefit from RQSs as envisaged under Alternatives II and III.

Non-RES-E generators

Compared to the baseline, less RES-E will be produced in the Netherlands (and correspondingly more in Sweden) under Alternative III. Non-RES-E generators and imports will fill the gap with a (in the flexible Dutch power system) slightly upward pressure on the average base load price.[38] Hence, non-RES-E generators will benefit.

In the absence of additional measures (such as a biomass co-firing obligation for coal-fired power plants), the partly renewable co-firing generators stands to gain even more. The size of the latter gains depends also on the uncertain evolution of the biomass feedstock price, the coal price and the carbon price.

Table 6.4 *Alternative III versus Baseline: projections of electricity and RQS certificate trends, 2014 - 2020*

Analysis domain	Support scheme	Variable	Unit	Year 2014	2015	2016	2017	2018	2019	2020
NL	Baseline	RES-E production	TWh	22.6	23.2	25.8	30.4	34.0	39.9	45.3
	ALT III			22.6	22.9	25.3	29.8	30.6	33.3	35.3
SE	Baseline	1)		20.7	10.4	11.1	11.5	13.3	13.4	13.5
	ALT III	1)		20.7	10.4	12.4	14.2	17.3	18.7	20.2
	Baseline	2)		85.9	87.5	89.2	90.8	92.4	94.0	95.5
	ALT III	2)		87.0	89.6	92.7	95.8	98.8	101.8	104.8
NL	Baseline	Other production	TWh	100.5	101.1	99.5	96.0	93.4	88.5	84.2
	ALT III			100.5	101.3	99.9	96.6	96.8	95.1	94.2
SE	Baseline			71.4	68.4	68.2	68.5	68.5	68.5	68.1
	ALT III			71.2	68.2	68.1	68.2	67.5	67.4	67.2
NL	Baseline	Final power demand	TWh	117.8	118.9	120.0	120.9	122.0	123.0	124.0
	ALT III			117.8	118.9	120.0	120.9	122.0	123.0	124.0
SE	Baseline			133.2	134.4	135.5	136.7	137.8	139.0	140.1
	ALT III			133.2	134.4	135.5	136.7	137.8	139.0	140.1
NL	Baseline	Baseload power price	€ct / kWh	5.81	5.87	5.93	6.00	6.07	6.12	6.20
	ALT III			5.81	5.87	5.94	6.01	6.09	6.15	6.24
SE	Baseline			4.85	5.03	5.10	5.11	5.20	5.28	5.37
	ALT III			4.85	5.02	4.96	5.01	5.08	5.12	5.19
NL	Baseline	Elcert price	€ct / kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	ALT III			3.52	3.51	3.51	3.50	3.50	3.50	3.49
SE	Baseline			3.79	3.46	3.24	3.07	2.84	2.62	2.39
	ALT III			3.52	3.51	3.51	3.50	3.50	3.50	3.49

1) Qualifying RES-E, based on Swedish RPS target and final demand projections.

2) Includes non-qualifying RES-E: mainly hydro power from installations before the Swedish RPS was introduced.

Source: authors' projections based on *i.a.* (SEA, 2009)

Suppliers

To the extent that changes in cost burdens for end-users will not materially impact on final power demand, distributional effects on suppliers will be neutral. The lion's share of RES-E related cost charges is likely to fall on households. In our modelling exercises we have assumed that power demand is completely inelastic to price changes. Empirical research has shown that in practice the price elasticity of household electricity demand comes rather close to this, for modelling work, convenient assumption.

Electricity end-users

Our projections indicate that a substantially lower cost burden for end users will be the implication of adopting the Alternative III support scheme compared to the baseline. This is based on

38 Should a stringent biomass co-firing obligation be implemented as an additional measure parallel to introducing an RQS, the upward pressure on Dutch wholesale power prices will be more pronounced.

three underlying effects:
1. A very small negative effect as a result of slightly upward base load power prices.
2. A large positive effect due to SDE cost savings from which ultimately power consumers benefit.
3. A fairly large negative effect due to RQS certificate costs being passed on from suppliers to end-users.

A detailed analysis of distributional effects and how to mitigate negative ones is beyond the scope of the current study. It would seem that the impact of adopting Alternative III on the international competitiveness and regulatory flexibility regarding future developments merits special consideration. To the extent that large power users are exposed to international competition and worldwide, notably EU-wide, large power users are exempted from the burden of RES-E support schemes, Dutch large power users would seem to be granted a (partial or complete) waiver as well. The Swedish RQS, where in 2008 41.6 TWh of the 94.0 TWh of final power demand that participated in the RQS certificate scheme was exempted from target compliance, might well give some useful directions as to how to address this issue. Companies using at least 40 MWh / SEK million of company turnover get a partial (at least 50%) or complete waiver (SEA, 2009).

Concluding observations
The largest effects measured against the baseline, fall upon RES-E generators, other generators, and power consumers. Our projections indicate that - depending on technology-specific policy choices by the Dutch government and in the absence of non-SDE supplementary measures - among RES-E generators especially high-cost generators (offshore wind; biomass stand-alone) stand to lose and biomass co-firing generators stand to gain. Other (non-RES-E) generators will benefit. (Non-privileged) power consumers stand to gain substantially in terms of lower RES-E stimulation related surcharges on their electricity bills.

6.5.2 Effects on Swedish stakeholders
A detailed investigation of the net benefits for the Swedish economy at large and distributive effects in the Swedish society is beyond the scope of this study. Information presented in Table 6.4 does give some broad indications though.

Exercises with the COMPETES model, introduced in Appendix A, suggest that - as measured against the baseline (no international expansion of the RQS to the Netherlands) - Dutch imports of RQS certificates up to a level of about 9 TWh is to lead to a maximum upward effect of the RQS certificate price of 1.1 €ct/kWh to a level of 3.49 €ct/kWh in 2020, after which this upward effect will gradually disappear. Remarkably, the resulting extra RES-E production in Sweden is likely to have a much stronger downward effect on the average base load price in Sweden than the corresponding reduction in the RES-E production expansion in the Netherlands will have on the average Dutch base load price in opposite (upward) direction.[39] This suggests that the Dutch electricity network is more flexible than the Swedish one. Differences in network topology, robustness and flexibility (also on the demand side) of the respective power network systems and the size of interconnections to evacuate surpluses and import national power deficits might be undercurrents of this result.

According to indications yielded by our modelling exercises, the *Swedish RES-E sector* at large is projected to be a strong winner, and particularly the Swedish onshore wind sub-sector. The drop in base load power prices in Sweden is good news for power users and bad news for *power generators that do not qualify for RQS certificates* (including operators of pre-2003 hydro

[39] This statement does not make allowance for the possible concomitant introduction in the Netherlands of a biomass co-firing obligation for coal-fired power plants. Such introduction could more strongly push up wholesale power prices in the Netherlands.

power plants). On average, qualifying generators will be more than compensated by extra revenues from RQS certificate sales.

With due consideration for the limited refinement of our modelling exercises and our less profound general knowledge of the Swedish electricity system and its broader societal context, we make the following tentative observations about the effects of international expansion of the renewable quota system to the Netherlands for *Swedish electricity consumers*. Assuming a zero price elasticity of power demand exercised by unprivileged consumers, the overall effect of the Alternative III scenario on Swedish power consumers can be broken down into the following underlying effects:

1. A power retail price increasing effect due to the at least initially significantly upward reacting RQS certificate price. Depending on company market strategy and competition circumstances on the Swedish retail market, Swedish suppliers will pass through their costs of acquiring RQS certificates to comply with the RQS target more or less completely to their customers on a *pro rata* basis. The extent of the effect depends on the RQS certificate price reaction and on the system target.
2. A power retail price decreasing effect due to the reaction of the wholesale market on the extra RES-E production in Sweden induced by the export to the Netherlands of certificates originated in Sweden and its knock-on effect on the power price on retail market in Sweden.

This combined effect regards all final power users.

Our *initial* expectation was that the first effect from the upward RQS certificate price reaction would dominate the second effect from the downward power price reaction. Yet - keeping in mind our remarks on the crudeness of our simulations of the Swedish distributional effects - our modelling outcomes suggest that the second effect is the dominant one. If this result can be confirmed indeed by more profound research, this will be good news for Swedish electricity consumers.

6.6 Concluding observations

Our quantitative analysis has focused on those effects that can be quantified with a fair amount of robustness. For example, in our quantitative analysis we have refrained from making sweeping, speculative assumptions on the nature and volume of external effects of specific ‘innovation pathways’, the innovation dynamics of inter-technology competition, the strategic value of bottom-up harmonisation of national support schemes, etc. Taking the baseline scenario as benchmark, our results indicate in a robust way with respect to choice of discount rate and projected RES-E mix trends that Alternative III is substantially more Dutch social welfare enhancing than both Alternatives I and II.

Our analysis of aggregate effects of the Alternative III scenario for Swedish society against a national RQS shaping the baseline scenario has not yielded conclusive results. More research on the Swedish perspective is needed involving relevant Swedish research institutes. In all, Swedish renewable generators applying qualifying technologies for participation in the renewable quota system are set to be clear winners and other Swedish generators clear losers. Less robust indications suggest that Swedish consumers may benefit.

7. Conclusions and recommendations

7.1 Conclusions

A quantitative analysis has been made of the net benefits associated with a transition of RES-E market support in the Netherlands to either one of three alternatives support scenarios as per 2014. The impact of the alternative scenarios has been compared to the baseline scenario, assuming an intensified continuation of the existing SDE support scheme. All scenarios considered, including the baseline scenario, were assumed to have a policy intensity leading to a RES-E share in total Dutch electricity consumption of 35% in 2020 and similar time trajectories of RES-E volume. As RES-E installations commissioned in 2020 affect cost and revenue cash flows until 2035, whilst regulatory costs have to be made in preparation of a shift in RES-E support system per 2014, our analysis has covered the period 2013-2035 with distinct emphasis on the medium-term period 2013-2020.

Key results of our model simulations indicate the following:

- Major factors explaining differences in the results for the alternative systems are projected differences in levelised cost of electricity per RES-E technology, projected divergences in RES-E mixes within the RES-E share in gross electricity consumption as well as diverging balancing costs. Extra regulation costs to enable the shifts to each of the three alternative support schemes play a minor role. In Alternatives II and III the RES-E mix is to a large extent determined by market forces in contrast to Alternative I. Yet also in the 'market-based' scenarios a major role has to be played by the public sector in ensuring a well-functioning certificates market. In Alternative I, German-like FIT, no portfolio cost optimisation takes place. In the baseline the Dutch RES-E portfolio is optimised to some (imperfect) extent by the public sector based on asymmetric information through setting the ceilings in the annual technology-specific budget allocations.
- Initially, *when keeping the RES-E mix evolution the same as in the baseline,* all three alternative systems yield reductions in RES-E stimulation cost compared to the baseline SDE system. The main reasons are:
  - The technology-specific cost per unit of energy for project developers tends to be affected in downward direction, most notably for Alternative I (the feed-in tariffs system). It should be mentioned that in order to avoid arbitrary and controversial assumptions, our projections regarding Alternative I have not internalised the negative externalities related to the mandatory shift of certain market risks from RES-E generators to other market players. An exception to this is the extra balancing cost caused by wind power generators, for which provisions have been made in our projections.
  - When allowing for diverging RES-E mix projections the next trends are envisaged:
    - The shift to hybrid RQSs II and III fosters (i) higher load factors for onshore wind power (less system optimisation towards 2,200 full load hours) and (ii) deployment of low-cost RES-E technology (large-scale biomass digestion, biomass co-combustion) at the expense of high-cost small-scale RES-E technology.
    - A joint hybrid RQS with Sweden will foster extra RES-E generation in Sweden at the further expense of high-cost RES-E technology in the Netherlands.
    - Alternative I is projected to become increasingly less efficient, compared to the SDE system. Key is the inefficiency in the RES-E portfolio that FIT engenders.
    - In the medium run, efficiency gains of Alternative III compared to the baseline will be increasingly more pronounced and robust. Additional efficiency can be obtained over an expanded system domain through *gains from (international) trade*.
    - For Alternative II significant efficiency gains are initially projected that would be partly eroded in the longer term. A major underlying factor is that because of great uncertainty about what will happen after 2020, especially regarding RES-E support

policies at EU-level, we have made a simple assumption about stable RES-E volumes and stable RES-E mixes after 2020. This assumption works out negatively for the RQS market-based support mechanism with an inherent tendency towards cost optimisation of the RES-E mix.

Table 7.1 illustrates these main trends. In meeting the compliance obligations with respect to European RES Directive 2009/28/CE, a support scheme shift towards hybrid RQS yields net benefits to Dutch society. Particularly the increase in the Dutch household electricity bills on account of RES-E market stimulation is set to be less burdensome. This holds for a modest extent for Alternative II but quite strongly so for Alternative III were large *gains from trade* can be realised.

Table 7.1 *Net benefits from a Dutch socio-economic perspective of a shift in 2014 from the prevailing SDE support scheme to three alternative support schemes*

		Net present value in 2010 (€$_{2010}$ billion)					
Period			2013 - 2020			2013-2035	
Discount rate		0 %/a	2.5 %/a	5 %/a	0 %/a	2.5 %/a	5 %/a
Alt I	FIT: same RES-E mix evolution as in the baseline	0.2	0.2	0.2	0.9	0.7	0.5
Alt I	FIT: allowing for divergent RES-E mix evolution	0.0	0.0	0.0	-1.4	-0.8	-0.5
Alt II	National hybrid RQS: same RES-E mix evolution as in the baseline	1.2	1.0	0.8	0.9	0.9	0.8
Alt II	National hybrid RQS: allowing for divergent RES-E mix evolution	1.5	1.3	1.0	1.9	1.6	1.4
Alt III	Joint hybrid RQS support scheme with Sweden	2.9	2.4	2.0	9.0	6.6	4.9

7.2 Recommendations

Support scheme choice

We advice to consider the transition in Dutch support scheme from the current SDE support scheme to an integrated mix of the SDE scheme with a national certificates-endorsed, demand-side renewable quota system. The most important consideration in this regard is of strategic nature: to bring the Netherlands in an excellent position to capitalise on opportunities for bottom-up harmonisation of RES-E support schemes in the EU.

The RQS component of the hybrid support scheme can best be aligned to the Swedish renewable quota system. Should a positive decision be made, it is advised to start negotiations with Sweden (and Norway if the envisaged joint Swedish-Norwegian RQS materialises) to enter into expansion of the RQS to the Netherlands. Realisation of Dutch participation in a well-designed joint hybrid RQS scheme would bring substantial socio-economic benefits to Dutch society.

For the sake of comparison, we have assumed in our modelling that the realisation of a joint hybrid RQS support Swedish - Dutch support scheme takes place as per 1 January 2014. In practice, a launching date after a smooth realisation of a national RQS-SDE system and a smooth negotiation process of around 1 January 2016 would seem to be a more realistic planning. The scenario case of a joint hybrid RQS support scheme between Sweden and the Netherlands is for proof of concept. Any further international expansion would increase the aggregate social welfare benefits as in the larger system domain more scope exists for efficiency enhancing trade. But due to distributional factors and high dependence on system design, a minority of partner countries *may* stand to lose from further expansion. As for the potential for efficiency improvement in pan-EU RES-E stimulation, we refer again to the results of a pan-EU modelling exercise by EWI indicating an EU-wide potential of some €100 billion RES-E stimulation cost reduction over a 13-year period (Fürsch *et al.*, 2010).

Alignment to the Swedish support scheme as much as possible and in an appropriate way for the Dutch situation would seem an important design consideration. The Swedish scheme has proven to be effective in bringing about compliance with pre-set RES-E expansion targets. At the same time it is the most efficient scheme in fostering the expansion of RES-E deployment within the EU to date. Well functioning RQSs elsewhere e.g. the one run by ERCOT of Texas, USA, should also be considered. Moreover, the lessons learned from Europe's less well-performing RQSs (e.g. in the UK, Italy and the Belgium regions) should also be taken into consideration.

Challenge 1: Supply-side market power within the RQS certificate market
Prevention of potential exercise of supply-side market power by companies with co-firing generation assets is a key design issue. The Swedish practical experience suggests that with good market design this issue can be mitigated adequately, much better than is the case, for example, with the power retail market (Swedish Energy Agency, 2008 and 2009). A similar conclusion was reached in a CPB study (Koutstaal *et* al, 2008). A profound analysis of the design details is beyond the scope of this study. For the Netherlands, some broad design features to mitigate exercise of market power on a national RQS certificates market for detailed further consideration are:

- A good integration into the current SDE scheme. This will minimise windfall profits of generators benefitting from both RQS certificate revenues and additional SDE subsidy for RES-E technologies needing supplementary SDE support, assuming properly cost-reflective SDE subsidy base rates.

- Diversification of eligible RES-E sources: potentially large volume technologies such as offshore wind are to be included in order to diversify the supply of RQS certificates.

- Unlimited period of RQS certificate validity, i.e. unlimited banking. Banking complicates gaming efforts, increases its risks and reduces its potential benefits.

- Consider large RES-E installations to be mandated to offer RQS certificates originated on their behalf for public auctions with entitlement to the full *pro rata* auction revenues.

- A waiver to such auctions is to be applied for RQS certificates implied in *long-term* bilateral RQS certificate delivery contracts, including RQS certificate deliveries included in purchasing power agreements. Such contracts might be crucial to come to financial closure of RES-E projects with front-loaded financing requirements, such as offshore wind farms.

- Consider to include the flexibility that biomass co-firing installations of a certain minimum MW capacity might be required to produce a multiple number of MWh exceeding one in order to contain windfall profits for operators using this technology. The RQS certificate market supervisory authority should apply such flexibility with restraint based on pre-set transparent rules.

- Consider to introduce sub-categories for co-firing installations that properly reflect the wide diversity in cost characteristics within this technology category with cost-reflective differential support treatment.

- Penalties that discourage under-compliance, e.g. 150% of last year's average certificate price (Sweden).

- Last but not least, international expansion of the RQS will make the RQS certificate market more liquid and robust against gaming.

Moreover, the RQS certificate supervisory authority and the central government should monitor the functioning of the RQS certificate market and, when needed, intervene to achieve RQS certificate price formation within a published pre-set target bandwidth. Too low prices discourage investments in RES-E technologies solely supported by RQS certificate revenues, whilst too high prices significantly exceeding the projected cost gap of the lowest cost large RES-E technology in need of support by the hybrid RQS may lead to unacceptable windfall profits. Instruments at the disposal of the authorities may include:

- A broad diversity of RES-E technologies participating in the renewable quota system.

- System target setting on a rolling planning basis with close monitoring of the certificates market.

- Integrating RQS certificate market considerations in setting SDE subsidy base rates.

- Integrating RQS certificate market considerations in setting technology-specific SDE budget ceilings.

- Allowing banking of RQS certificates.

- At least initially a minimum RQS certificate price could be guaranteed as was done when the RQS certificate system was introduced in Sweden.

- The option of raising the quantity of generated RES-E electricity per RQS certificate issued to more than one MWh might be exercised for some specific technologies notably co-firing under certain well-specified market conditions.

Another major issue is the streamlining of permitting procedures. Monitoring and, when needed, interventions by the central government are in order, should undue delays occur at lower government levels. This issue is not only key in achieving very ambitious RES-E sub-targets, but is also of key importance for a well-functioning national RQS certificate market.

Challenge 2: Exposure of large power consumers to foreign competition

The advantage of demand-side RQSs is that flexible rules can be applied on the demand side with respect to who participates in the system and to what extent. This contrasts to a supply-side RQS, as currently applied in Italy. Generators in Italy will tend to include the costs of the Italian Green Certificates scheme they are subjected to into their offer prices in the wholesale power market. This results in across-the-board higher Italian wholesale prices, indiscriminately for large and small power users alike. In the UK, loads with a direct connection to the transmission system (accounting for 2% of total power consumption) have been excluded from the UK Renewable Obligation. This support scheme is a rather complex example of a demand-side RQS variety. Industrial plants connected to UK (medium/low voltage) power distribution networks fully participate in the Renewable Obligation system. Conversely, in Sweden large power consumers are partly or almost fully exempted from participation in the RQS (Swedish Energy Agency, 2009). The Swedish system might provide good clues as to how to address this issue.

Challenge 3: Cost-reducing innovations to boost dynamic efficiency
The application of a properly designed RQS support scheme in the Netherlands has clear advantages in terms of optimising in the short term economic efficiency in spending additional domestic resources to achieve a given objective for the expansion for RES-E. So-called *static efficiency* is achieved as market players are stimulated to invest in those eligible RES-E technologies and at those locations where they perceive the lowest financial gap. When such a scheme expands towards more countries, especially to countries with a rather diverging renewable energy resource base, the welfare enhancing benefits over the total (expanded) system domain will increase further.

Moreover, a properly designed RQS boasts some rather benign features to boost the efficiency of renewable electricity generation *over time*. Firstly, because of being subjected to market competition generators and their technology, vendors will be incentivised to take commercial risk in the introduction of new technology with potential for cost reduction. Conversely, when market parties are pampered by regulatory rents, the existential need to take risk to achieve a competitive edge is lacking.[40] Moreover, because of inter-technology competition the scope for informal intra-branch collusion behaviour and lobbying toward determination of attractive technology-specific feed-in tariffs or premiums is eroded for those technologies that would only be supported through participation in the RQS and by complementary SDE support.

Harmonising market-based RES-E support among (part of the) EU Member States enhances the opportunities for economies of scale for production up-scaling. There is an enormous potential for EU-wide efficiency improvement in RES-E generation support through market-based harmonisation as compared to target achievement through intensification of existing support policies only in fully fragmented EU RES-E markets (Fürsch *et al.*, 2010). It is quite hard if not impossible for the national public authorities in non-harmonised markets to mimic market-based realisation of this potential through state trade in *statistical transfers* or through application of the *project-based co-operation mechanisms,* defined in Directive 2009/28/CE.

Yet the application of a *pure RQS* without additional measures to foster cost-reducing technological development *may* hinder a possibly fast technological development of currently high-cost technology. This is something that nobody can establish in a robust way, simply because of the sheer fact that against the results of the real future support regime the results of every imaginable other regime is counterfactual.

A *hybrid RQS* support scheme can help to speed up technological development of currently expensive RES-E technology to possible commercial maturity. A hybrid scheme leaves room for subsidiary support mandated by national public sector authorities to national players, using 'promising' RES-E technologies. So far, EU jurisdiction, Directive 2009/28/CE and the guidelines for state aid to environmental protection turn out to offer ample legal scope for member-state-specific state aid. RD&D support would seem the most important policy instrument for promising RES-E technology with a large financial gap (Frondel, Ritter, Schmidt, Vance, 2010). Moreover, a hybrid RQS support scheme enables the provision of technology-specific supplementary support to market deployment as it helps to bridge the remaining financial gap.

It is advised to constrain supplementary support to market deployment of high cost RES-E technology in a transparent and predictable way. Extreme stop-go changes in annual technology-

[40] Large regulatory rents for RES-E operators applying a certain eligible technology may perspire across the RES-E supply chain to e.g. technology vendors and e.g. to land owners of the sites of RES-E installations. For example, over the last few years substantial regulatory rents were captured by PV generation installations in Germany which initially trickled down to German PV module manufacturers, who initially saw their profits rising fast. Later on German PV module manufacturers were outcompeted by some of their Chinese peers, making for substantial regulatory rent transfers to China at the expense of the German non-privileged electricity users. Recently BMU has implemented a series of PV feed-in tariff cuts in a bid to stem these regulatory rent transfers to China.

specific support ceilings should be avoided. Given the fact that the public sector does not have an impeccable track record in 'picking the winners', prudent use of supplementary SDE support is warranted. On the other hand, a certain market exposure of high-cost technology yields valuable feedback from target end-users to technology developers. The bottom line is that the SDE component of a hybrid RQS-SDE scheme enables technological diversification of RES-E support and the pre-empting of technological lock-ins. Moreover, keeping the SDE scheme as a major component in a hybrid RQS ensures a fair extent of policy continuity for RES-E investors.

Challenge 4: Marketing green power products

Introduction of a hybrid RQS in the Netherlands has implications for Dutch vendors of green power products to environmentally concerned power customers. They need to better educate their customers on the co-existence of support mandated by the public sector and the possibilities to promote the expansion of RES-E by the voluntary market. This does not so much relate to the choice of public-sector mandated RES-E market support scheme. It rather relates to the choice made in Directive 2009/28/CE to restrict the role of Guarantees of Origin to function solely as an instrument to verify mandatory disclosure to consumers of a supplier's electricity mix and for verification purposes of green power offerings in the voluntary market. The example of Sweden shows that a voluntary market for green power products can co-exist with a certificates-endorsed RQS. We refer for example to the green products sold in Sweden under the Bra Miljöval label.

Challenge 5: Grid constraints in Sweden

Dutch demand for Nordic RQS certificates on the RQS certificate price in a SE (-NO) - NL RQS certificates-based joint support scheme can be managed through the SDE by:

- Including considerations on the functioning of the RQS certificate market in setting the subsidy base rates.
- The same applies for establishing annual technology-specific funding allocations.

Intervention might be needed, especially in the initial phase of the merging process of Dutch and Swedish certificates schemes and at times when the certificate price in the joint RQS certificate market moves up or electricity prices in Sweden are pushed down to undesirable levels. This can relate to target setting for the joint system if compatible with system design. Moreover, Dutch authorities might, for example, mandate larger annual technology-specific support budgets for the marginal Dutch RES-E technology receiving supplementary SDE-based support. This way the pressure from demand exercised by Dutch RQS participants for RQS certificates originated in Sweden will be reduced and hence the pressure put on Swedish competitive RES-E producers/investors to push up the volumes.[41]

Removing grid constraints through grid reinforcements and notably more interconnections is another way of mitigating grid congestion issues. Given current network pricing regulations, this could make Swedish consumers suffer from higher grid charges. A longer term solution to this problem would be pan-EU harmonised introduction of optimised time-dependent cost-reflective grid service charges to all users of public grids. At times of congested grids, injected power should be charged with relatively high cost-reflective transport service charges when local supply exceeds local demand, and the other way around to power consumers when local demand exceeds local supply.

[41] The reverse - Dutch authorities mandating lower annual SDE budget ceilings - could be applied in situations when the RQS certificate price retreats to unattractively low levels for project developers, especially for those considering technologies supported by RQS certificates only. Such actions have to be undertaken prudently in a well balanced trade-off with the desirability to offer a stable investment framework for project developers.

Prior to such reforms on network service charging, a contribution by Dutch consumers to network reinforcement in Sweden might be considered in possible negotiations with Sweden in the case of net Dutch imports of RQS certificates from Sweden. This could take the form of moderate additional payment for statistical transfers in the sense of directive 2009/28/EC, i.e. in addition to the payment for imported RQS certificates. The Swedish state agency trading in statistical transfers could allocate the proceeds from such additional transactions to Swedish network operators, whilst the Dutch counterpart organisation could allocate the bill to TenneT to be included in the RES-E surcharge to unprivileged consumers. Compatibility with competition law has to be considered before introducing such arrangements.

In accordance with our modelling results, based amongst others on data kindly provided by SEA, scope was identified for imports of Swedish RQS certificates by the Netherlands to a maximum of about 9 TWh. Yet, the implementation of additional new Swedish RES-E capacity or constraints in the Swedish electricity grid may be larger than allowed for in our modelling exercises. Hence, much more detailed analysis is needed in this regard to verify as to which levels of imports and exports (e.g. at times of poor availability of Nordic hydro resources) are feasible.

Final observation
Changing the Dutch RES-E support scheme should not be undertaken just for the sake of complying with the Dutch commitment to the EU with respect to its mandatory RES target in 2020. Results of our modelling exercise over an extended period up to 2035 validate our recommendation that market players should be offered a reliable long-term support framework. The long-term feature is part of the design of well-functioning RQS schemes.

References

Andor, M., K. Flinkerbusch, M. Janssen, B. Liebau, M. Wobben (2010). *Der EEG-Ausgleichsmechanismus: die Ausnahme muss zur Regel werden.* Energiewirtschaftliche Tagesfragen. 60 (11). pp. 28-31.

BMU (2007): *Renewable energy sources in figures - national and international development - national and international development.* German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety. Environmental Policy Series. Public Relation Division. Berlin.

BMU (2010a): *Erneurbare energien in Zahlen; Nationale und Internationale Entwicklung.* German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety. Berlin. June 2010.

BMU (2010b): *Einfluss der Förderung erneurbarer Energien auf den Haushaltsstrompreis in den Jahren 2009 und 2010 - einschl. Ausblick auf das Jahr 2011.* German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety. Berlin. 31 August 2010.

Börkley A., A. Jahn (2010): *Der Ausgleichmechanismus als Startpunkt für die Integration der Erneurbaren in den Energiemarkt*. Energiewirtschaftliche tagesfragen. Vol. 60 (5). 13-15.

Breitschopf, B., M. Koblasa, F. Sensfuß, J. Steinbach, M. Ragwitz, U. Lehr, J. Horts, U. Leprich, j. Diekmann, f. Braun, M. Horn (2010a). *Einzel- und gesamtwirtschaftliche Analyse von kosten- und Nutzenwirkungen des Ausbaus Erneurbarer energien im deutschen Strom- und Wärmemarkt*. Interim report by Fraunhofer ISI, GWS, IZES and DIW Berlin, commissioned by BMU, the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety. March 2010.

Breitschopf, B., M. Koblasa, F. Sensfuß, J. Steinbach, M. Ragwitz, U. Lehr, J. Horts, U. Leprich, j. Diekmann, f. Braun, M. Horn (2010b). *Einzel- und gesamtwirtschaftliche Analyse von kosten- und Nutzenwirkungen des Ausbaus Erneurbarer energien im deutschen Strom- und Wärmemarkt*. *Kurz-update der quantificierten kosten- und Nutzenwirkungen für 2009.* Brief update report by Fraunhofer ISI, GWS, IZES and DIW Berlin, commissioned by BMU, the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety. May 2010.

de Bruyn, S.M., Blom, M.J., Schroten, A., Mulder, M., (2007), '*Leidraad MKBA in het milieubeleid*', CE, report 07.7350.14, Delft.

Bundesnetzagentur (2009): *Monitoringbericht 2009*. Bonn

Bundesrepublik Deutschland (2010a): *Nationaler Aktionsplan für erneurbare Energie gemäß der Richtlinie 2009/28/EG zur Förderung der Nutzung von Energie aus erneurbaren Quellen*. Berlin

Bundesrepublik Deutschland (2010b): *Energiekonzept*. BMWI/BMU. Berlin. 28 September 2010

CBS (2009): *Renewable energy in the Netherlands 2008*. The Hague/Heerlen.

Copenhagen Economics (2010): How to support RES-E in the EU?, Draft report, 30 March 2010.

Daniëls, B, S. Kruitwagen (ed.) (2010): *'Referentieraming energie en emissies 2010-2020'.* ECN/PBL, report ECN-E--10-004, PBL 500161001. Petten/Bilthoven. April 2010.

Deutscher Bundestag (2010): *EEG-Umlage 2010*. Actueller begriff. Nr. 21/30. Deutscher Bundestag/Wissenschaftlische Dienste. 25 March 2010.

Egenhofer, C., J.C. Jansen (2006): *'A timetable for harmonisation of support schemes for renewable electricity in the EU'*. European Review of Energy Markets. Vol. 1(2). 57-63

Eigenraam, C.J.J., Koopmans, C.C., Tang, P.J.G., Verster, A.C.P. (2000): '*Evaluatie van infrastructuurprojecten - leidraad voor kosten-baten analyse*', CPB/NEI, Den Haag/Rotterdam.

European Union (2008), *Commission staff working document - The support to electricity from renewable sources*

European Union (2009a): *Impact assessment guidelines*, SEC (2009) 92, Brussels, 15 January 2009.

European Union (2009b): *Directive2009/28/EC of the European Parliament and the Council of 23 April 2009 on the promotion of the use of energy from renewable sources and amending and subsequently repealing Directives 2001/77/EC and 2003/30/EC.* O.J. L 140/16. Brussels. 5 June 2009

EZ (2009): *Betreft Beantwoording kamervragen, gesteld tijdens AO van 3 maart jl.* Letter of Dutch Minister of Economic Affairs to Lower House of the Dutch Parliament. ET/ED/ 9072297. The Hague. 17 April 2009

Frondel, M., N. Ritter, C. Vance (2009): *Economic impacts from the promotion of renewable energies: The German experience.* RWI Projectbericht. Final report. Rheinisch-Westfälisches Institut für Wirtschaftsforschung. Essen.

Frondel, M., N. Ritter, C.M. Schmidt, C. Vance (2010): *Economic Impacts from the Promotion of Renewable Energy Technologies: The German Experience.* Energy Policy 38: 4048-4056

Fürsch, M., C. Golling, M. Nicolosi, R. Wissen, D. Lindenberger (2010): *European RES-E policy analysis.* Energiewirtschaftliches Institut (EWI), University of Cologne. Köln. April 2010

GreenStream (2010): *Analysis of the flexible support mechanisms in the directive on the promotion of the use of energy from renewable sources.* The Nordic Working Group for Renewable Energy. Final report. Copenhagen. 8 January 2010.

Hahn R.(2010). *Designing Smarter Regulation with Improved Benefit-Cost Analysis*. Journal of Benefit-cost Analysis. Vol. 1: Iss. 1, Article 5.

Held A., R. Haas, M. Ragwitz (2006): '*On the success of policy strategies for the promotion of electricity from renewable sources in the EU'*. Energy & Environment. Vol 17. 849-868.

Holttinen, H. et al. 2008): Impacts of large amounts of wind power on design and operation of power systems, results of IEA collaboration, *7th International Workshop on Large Scale Integration of Wind Power and on Transmission Networks for Offshore Wind Farms* 2008, Madrid, Spain

IfnE (2010): *Beschaffungsmehrkosten für stromlieferanten durch das erneurbare-Energien-Gesetz; 2009 EEG-Differenzkosten*. Ingenieurbüro für neue Energien. Teltow. August 2010.

Jansen, J.C. (2010): *Preliminary qualitative assessment of proposed measures to foster renewable and low carbon sources in the Dutch electricity mix*. ECN report ECN-E--10-012, February 2010.

Jansen, J.C, K. Gialoglou and C. Egenhofer (2005): *Market Stimulation of Renewable Electricity in the EU: What Degree of Harmonisation of Support Mechanisms if Required?* CEPS Task Force Report No. 56: CEPS, Brussels; http://www.ceps.eu/book/market-stimulation-renewable-electricity-eu-what-degree-harmonisation-support-mechanisms-requir

Jansen, J.C., A.J. Seebregts (2010): *'Long-term energy services security: What is it and how can it be measured and valued?'*, Energy Policy. Vol. 38. 1654-1664.

Klein, A. *et al* (2008): *'Evolution of different feed-in tariff design options - Best practice paper for the International Feed-in Cooperation'*. Research paper sponsored by BMU. 2nd edition. Fraunhofer Institute Systems and Innovation Research, Karsruhe, October 2008

Koopmans C., B. Tieben, M. van den Berg, D. Willebrands (2010). *Investeren in een schone toekomst. De kosten en baten van een duurzame energiehuishouding in Nederland*. SEO economisch onderzoek. Amsterdam, juli 2010.

Koutstaal, P., M. Bijlsma, G. Zwart, X. van Tilburg, Ö. Özdemir (2008): *Market performance and distributional effects on renewable energy markets.* CPB Document No 190. CPB. The Hague.

Langniß, O., J. Diekmann, U. Lehr (2009): *'Advanced mechanisms for the promotion of renewable energy - Models for the future evolution of the German Renewable Energy Act'*. Energy Policy. Vol. 37. 1287-1297

Lensink, S.M., J.W. Cleijne, M. Mozaffarian, A.E. Pfeiffer, S.L. Luxembourg and G.J. Stienstra (2009): *'Eindadvies basisbedragen 2010 - voor elektriciteit en groen gas in het kader van de SDE regeling'*, Report Report ECN-C--09-058, The Energy research Centre of the Netherlands, Petten, September 2009.

Ragwitz, M. *et al* (2007): *Asssessment and optimisation of renewable energy support schemes in the European electricity market: Final report*, Fraunhofer Institute Systems and Innovation Research, Karlsruhe, February 2007

Schiffer, H.W. (2009): *'Deutscher Energiemarkt 2008'.* Energiewirtschaftliche Tagesfragen. Vol. 59 (3), 52-66.

Schoots, K. (2010), *Innovatie en leercurven*, ECN-E--10-038, Petten, April 2010.

Sensfuß, F., M. Ragwitz, M. Genoese (2008): '*The merit-order effect: A detailed analysis of the price effect of renewable Electricity generation on spot market prices in Germany'*. Energy Policy. Vol. 26. 3086-3094

Sensfuß, F., M. Ragwitz (2009): 'Entwicklung eines Fördersystems für die Vermarktung von erneurbarer Stromerzeugung*'*. Themenbereich 4 / 6. Internationale Energiewirtschaftstagung an der TU Wien. Vienna

SenterNovem (2006): *Protocol Monitoring Duurzame Energie*. Version of year 2006. SenterNovem. The Hague.

Sijm, J.P.M., O.J. Kuik, M. Patel, V. Oikonomou, E. Worrell, P. Lako, E. Annevelink, G.J. Nabuurs, H.W. Elbersen (2004): *Spillovers of Climate Policy.* Report 500036 002. NRP-CC programme. Bilthoven. December 2004

Stratmann, K. (2010): *Herkulesaufgabe Netzausbau*, Energiewirstchaftliche Tagesfragen, 60 (11), p.4.

Swedish Energy Agency (SEA) (2005): *The consequences of an expanded electricity certificate market.* Stockholm.

Swedish Energy Agency (SEA) (2008): *The electricity certificate system, 2008.* Stockholm.

Swedish Energy Agency (SEA) (2009): *The electricity certificate system, 2009.* Stockholm.

Swedish Energy Agency (SEA) (2010): *Gemensamt elcertifikatsystem med Norge*, 2010. Stockholm.

Tilburg, X. van; J.C. Jansen; M.A. Uyterlinde; S. M. Lensink (2007): *Verplichting voor duurzame elektriciteit in Nederland. Verkenning van mogelijkheden en randvoorwaarden.* Report ECN - E -- 06-038 (in Dutch). ECN, Petten. March 2007

Tilburg, X. van; S.M. Lensink (2007): Kostenontwikkeling duurzame elektriciteitsopties 2020, Report ECN-BS--08-025, ECN, Petten.

VROM (2007): *Nieuwe energie voor het klimaat. Werkprogramma Schoon en Zuinig*. Ministry of housing, spatial planning and the environment (VROM). The Hague. September 2007

Werkgroep Actualisatie Discontovoet (2007): *Advies werkgroep actualisatie discontovoet.* The Hague. January 2007.

Glossary of abbreviations and acronyms

DSO	Distribution system operator
EEG	Erneurbare-Energien-Gesetz; German FIT law
EZ	(Dutch) Ministry of Economic Affairs
FIP	Feed-in premium (support system category)
GHG	Greenhouse gases
GW(h)	Gigawatt(hour) = 10^6 kW(h) = 10^9 W(h)
LCOE	Levelized Costs of Electricity
MS	Member State(s)
MW(h)	Megawatt(hour) = 10^3 kW(h) = 10^6 W(h)
NREAP	National Renewable Energy Action Plan
OFGEM	Office of the Gas and Electricity Markets: U.K. regulatory agency
PPA	purchasing power agreement
RES	Renewable energy sources
RES-E	Electricity from renewable energy sources
RO	Renewables obligation (support system), also often referred to as Renewable Quota System
RQS	Renewable Quota System: support system category, also called renewables obligation or renewable portfolio standard; often system compliance is administered by tradable renewable electricity certificates
RQS certificate	Tradable renewable electricity certificate to endorse RQS support schemes
TWh	Terawatthour = 10^{12} Wh = 10^9 kWh = 10^6 MWh = 10^3 GWh
TSO	Transmission system operator
VE-N	Association Energy-Netherlands: united Dutch trade association of electricity companies
VME	Dutch Association for Market Functioning trade associations of electricity companies in the Netherlands in Energy: one of the former two Dutch trade associations of electricity companies
W(h)	Watt(hour)
WACC	Weighted Average Cost of Capital

Appendix A Modelling issues

A.1 Modelling a Dutch national RQS certificate market

For the support system to work cost efficiently, it is important that the government has some control over the RQS certificate price. At a first step, the government could define its perspective on what an appropriate RQS certificate price would be. Note, however, that this price is not strictly set. All technologies from vintages that have a financial gap higher than the 'appropriate' RQS certificate price should also receive SDE subsidy.

An obvious question would be what an appropriate RQS certificate price is. The RQS certificate price should be such that only a few options with low production costs do not need additional SDE subsidy. If many options would not be granted supplementary subsidy in the presence of large technology-specific cost differentials, this would lead to a rather high RQS certificate price with attendant substantial windfall profits. Furthermore the marginal, i.e. price setting, option needs to be quite flexible[42] and would need to have a reasonably large volume, ensuring it to be price setting. To let this option be price setting the target should be set properly each year. By choosing which technology options allow for subsidy and which ones do not as well as the annual budget allocations the government can exercise a high extent of control over the RQS certificate price. Given the hybrid RQS-SDE design features outlined above, once a technology receives subsidy a developer will in theory be indifferent about what the final RQS certificate price will be. Ultimately, the financial gap will be covered by the SDE. However, to a developer who does not receive SDE subsidy, the RQS certificate price matters a great deal. The RQS certificate price should be at least high enough to cover his financial gap. Therefore these options will be price setting. A developer that receives subsidy will just bid what he will expect the marginal option will bid.

The strategy that has been followed to arrive at a cost effective scenario for the RQS-SDE scenario with appropriate targets per year is:

1. Define a reasonable target RQS certificate price, for example, 3 €ct/kWh.
2. Technologies that have a larger financial gap than the target RQS certificate price need subsidy.
3. Make sure that among the technologies that do not need subsidy the marginal option has enough volume, is flexible and that there are just a few technology categories with a smaller financial gap than the target price.
4. Set the target at such a level that the marginal option still has the flexibility to increase or decrease volume in a particular year.
5. Optimise the 2020 volume of the marginal option so as to exactly meet a RES-E share of 35% in total Dutch electricity demand.

Following this strategy, with an initial RQS certificate price of 2.0 €ct/kWh, our bidding curve in 2020 looks initially like Figure 7.1. However, developers that receive SDE subsidy also know that they have to bid a similar value as the marginal options; otherwise they will not cover their financial gap. The red vertical line in Figure A.1 denotes the RES-E target. The market-clearing RQS certificate price would be 2.8 ct/kWh. Some technology categories that receive hybrid support can use their relative advantage to bid lower than the market-clearing RQS certificate

[42] With flexible we mean that if a technology is marginal its mutations in annual production level should be well controllable so as to be just compliant with the RQS certificate system target, e.g. the requirement that RQS certificate system participants will meet a certain minimum standard of RES-E as a % of total power consumption (or deliveries to a supplier's customers). Obviously biomass co-firing is a technology that fulfils this criterion perfectly well.

price.[43] That will change the bidding curve, but up to a certain extent not influence the resulting RQS certificate price. The resulting final bidding curve is depicted in Figure A.2.

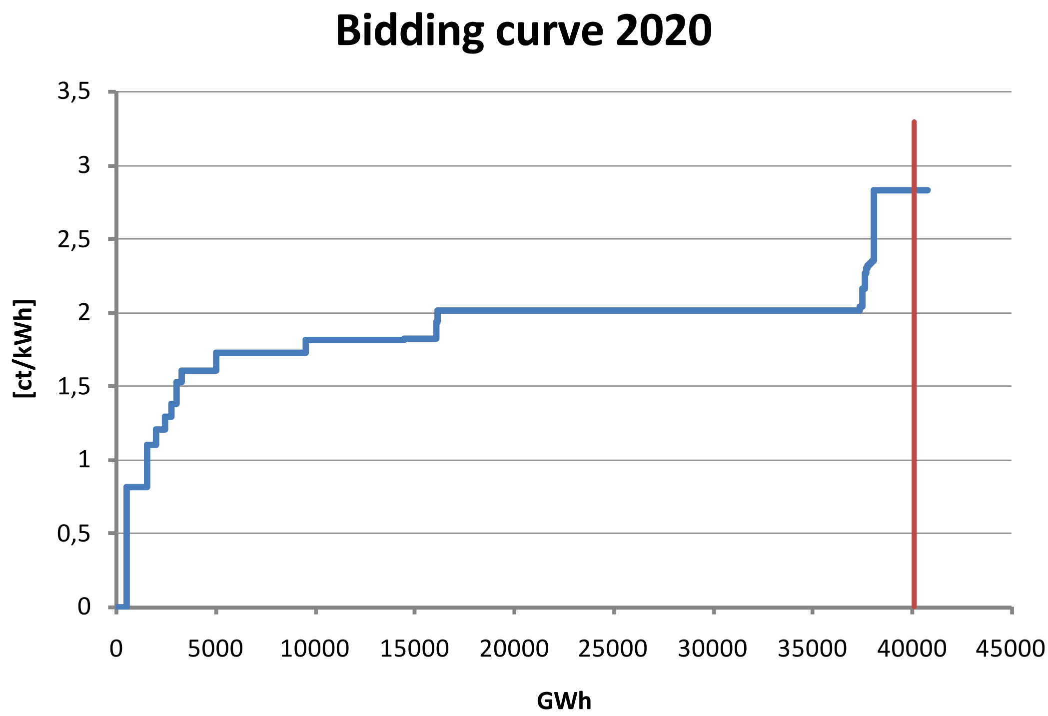

Figure A.1 *Initial bidding curve for option in 2020 assuming an intial RQS certificate price of 2,0 ct/kWh and a market-clearing price of 2,8 ct/kWh.*

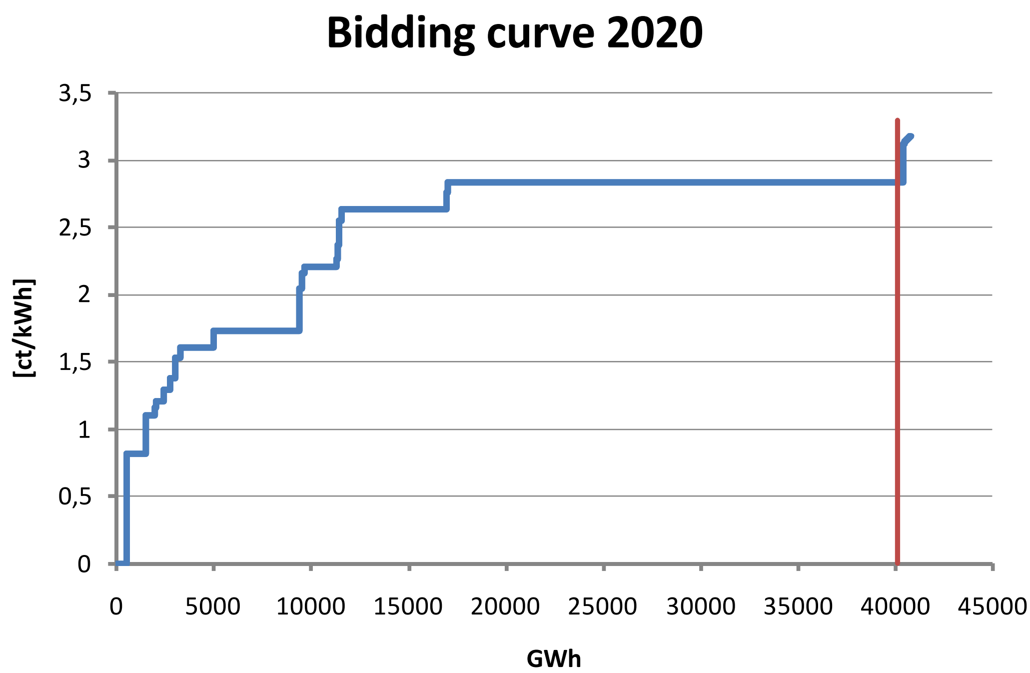

Figure A.2 *Final bidding curve at an RQS certificate market-clearing price of 2,8 ct/kWh.*

[43] This could hold e.g. for relative less expensive offshore wind parks if offshore wind were to be eligible for the hybrid RQS-SDE support scheme and for a generic offshore wind premium.

The projected evolution of the annual average RQS certificate price under the Alternative II scenario is shown in Table A.1. It hovers around 3.37 €ct/kWh in the period 2014-2020. All RES-E technologies are assumed to participate in the RQS certificate market. It is assumed that all installations that come into operation in 2012 or later participate. Biomass co-firing forms the notable exception: also all installations that were in operation before 2012 participate. Reason is that it is predominantly the biomass input which defines the financial gap, irrespective of the plant vintage. Although in our modelling the certificates-based RQS starts in 2014, it is important to include capacity from some years before the start of the system to have enough market liquidity when launching the RQS certificate market. A low volume of RES-E participating could otherwise results in a less well functioning RQS certificate market. Most technologies are assumed to need SDE subsidy on top of the revenues from RQS certificate sales. Biomass co-firing is assumed to never receive SDE subsidy once the RQS starts. The same is true for (large scale) other biomass digestion which will only come in operation from 2014 onward. Wind onshore is assumed to need extra subsidy initially. But for installations that come into operation from 2016 onward, the revenues from sales of certificates is projected to be sufficient to cover the financial gap.

Table A.1 *Alternative II, national Hybrid Renewable Quota System scenario: projected RQS certificate price evolution [€ct/kWh]*

	2014	2015	2016	2017	2018	2019	2020
RQS certificate market price	3.38	3.38	3.37	3.37	3.37	3.36	3.36

A.2 Modelling a Swedish-Dutch RQS certificate market

The information regarding RES-E developments and mix mainly comes from the recent SEA document (Swedish Energy Agency, 2010) and supplementary information kindly provided by SEA to the project team. Levelised production costs of technologies in Sweden have been based on these information sources.

The RES-E production that participates in the RQS certificate system in Sweden from 2014 is shown in Figure A.3. In 2020 the production is slightly more than 17 TWh. Note that the total amount of RES-E is substantially higher, but a lot of capacity is not eligible to participate in the post 2014 RQS certificate market.

In the case of a joined RQS with the Netherlands (ALT III) Sweden is producing about 9 TWh RES-E extra in 2020, see Figure A.4. Note that all extra RES-E production comes from wind onshore (7 TWh) and biomass stand-alone (2 TWh).

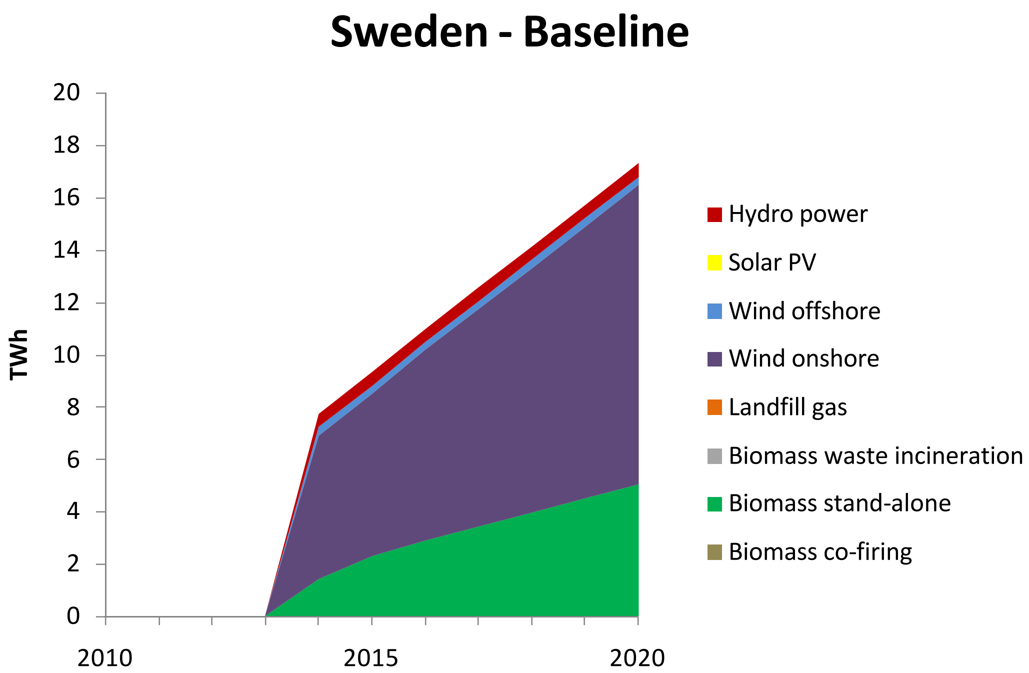

Figure A.3 *RES-E production [TWh] that participates in the RQS certificate system in Sweden from 2014 onwards*

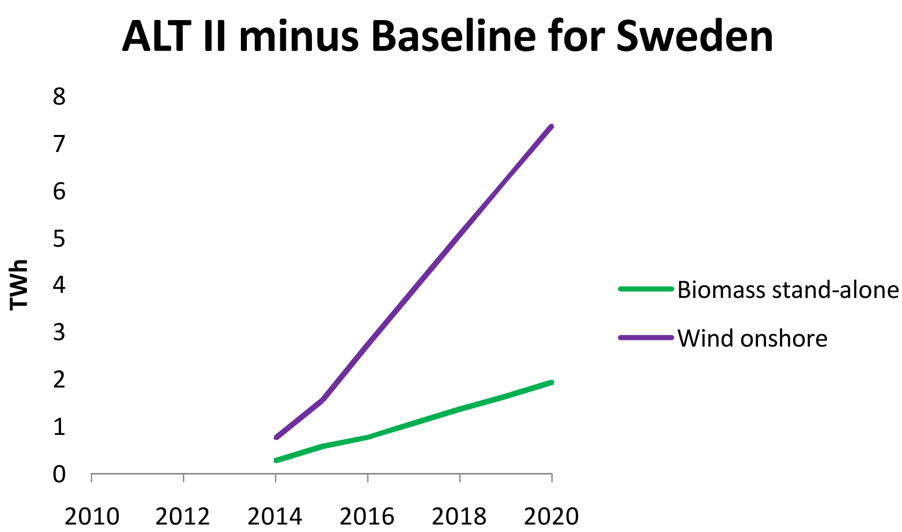

Figure A.4 *Extra RES-E production in Sweden in the combined RQS with the Netherlands*

Base load electricity prices for the Netherlands in the RQS-SDE alternative (ALT II) and combined RQS-SDE alternative with Sweden (ALT III) are shown in Figure A.5. Electricity prices for Sweden (baseline) and for ALT III are given as well. Note that the electricity prices in the two RQS scenarios are the same for the Netherlands. In ALT III the electricity prices drop in Sweden due to more RES-E production.

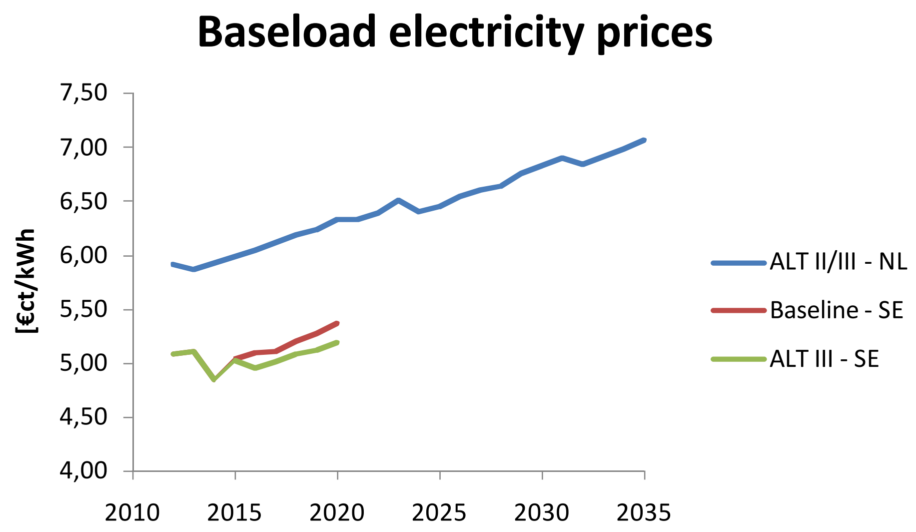

Figure A.5 *Baseload electricity prices [€ct/kWh] in the Netherlands and Sweden in the two RQS scenarios.*

The baseline ('only Sweden') RQS certificate price and RQS certificate price for a combined RQS with the Netherlands (ALT III) for the period 2014-2020 are shown in Figure A.6.

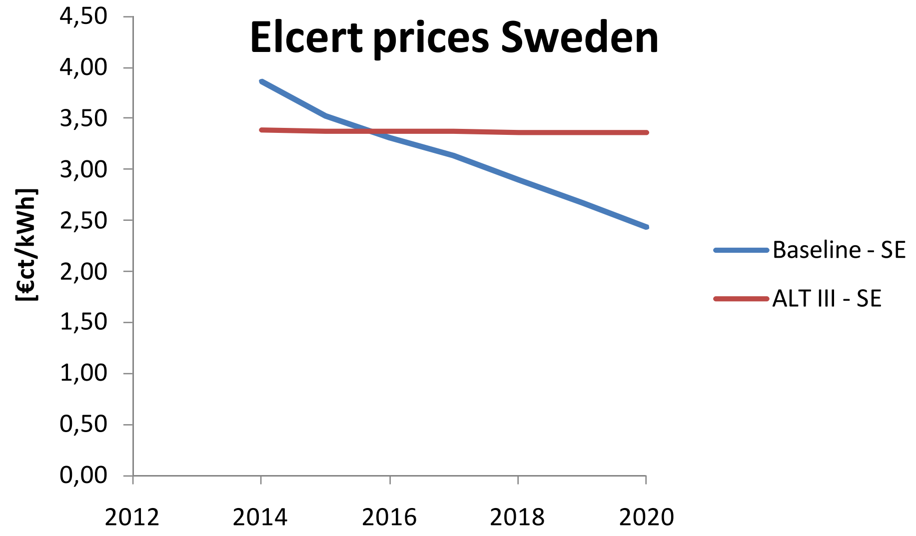

Figure A.6 *RQS certificate prices for the baseline of Sweden and for a combined RQS with the Netherlands (ALT III); the period 2014-2020*

A.3 Description of the COMPETES model

Electricity market and e-Prices: COMPETES Model
COMPETES is a partial equilibrium model of a transmission-constrained power market. The model contains three different types of agents: Generators, Arbitrageurs and TSOs. The generators and arbitrageurs try to maximise their profit; the TSO's try to maximise the value of transmission.

- COMPETES covers twenty European electricity markets including the Netherlands and Sweden and the corresponding transnational electricity network as shown in Figure 2. Here Denmark is divided into two parts that belong to two different non-synchronised networks,

while Luxembourg is added to Germany, because there is generally no congestion between them.
- In the latest version of the model (Summer 2008), COMPETES is extended from one to multi-hub system that deals with controllable DC lines between UCTE, Nordpool, and the UK that are not synchronised. This is important for representing flows between UCTE, Nordpool, and the UK asynchronous systems. In general, having controllable DC lines increases system power transfer capacity relative to a system which does not. Incorporating controllable DC lines in the model is an improvement of version 2.1.2.
- The time horizon of the model is one year. This year consist of 12 periods: winter, summer and midseason with each of these divided by off peak, peak, super peak and shoulder.
- COMPETES model consists of four market players; namely generator companies, arbitrageurs, transmission system operators (TSO), and consumers. The market structure of the model and the relationship between the market players is given in Figure A.7.
- Expansion of generation and transmission capacity is not considered. Instead exogenous scenarios of future generation and/or transmission capacity are defined and simulated to analyze the main effect.

Hence the main inputs of the COMPETES model are:
- The levels of demand at a specific period in a year for each region/country,
- The generation capacity developments (both conventional and RES) for each technology and each region/country , and the development of fuel and CO_2-prices which determine the short-term supply curve of each region/country,
- The transmission capacity between region/countries.

As an output, COMPETES model can compute:
- The allocation of generation and transmission capacity and
- The associated e-prices and consumption for either competitive or strategic behaviour (Cournot equilibrium) of generation companies.
- Network flows and potential bottlenecks between countries
- Consumer and producer surplus

Regarding RES-E, COMPETES takes as input the RES-mix as well as the capacity development of conventional technologies and calculates an e-price representing the short-run marginal cost of the system.

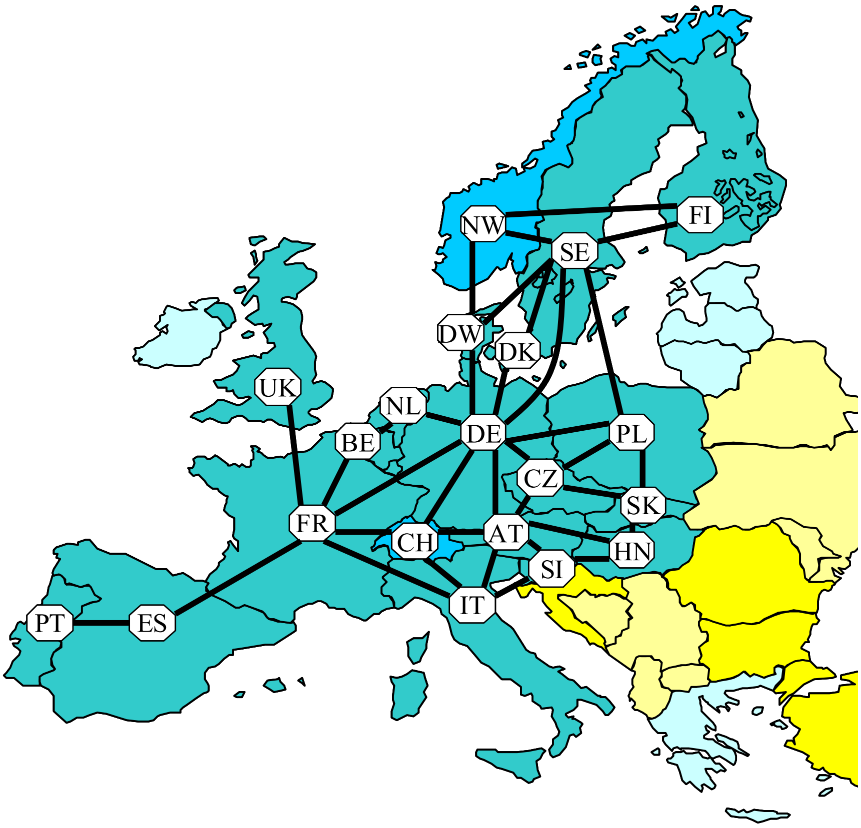

Figure A.7 *Physical representation of the electricity network in COMPETES 2.1.2*

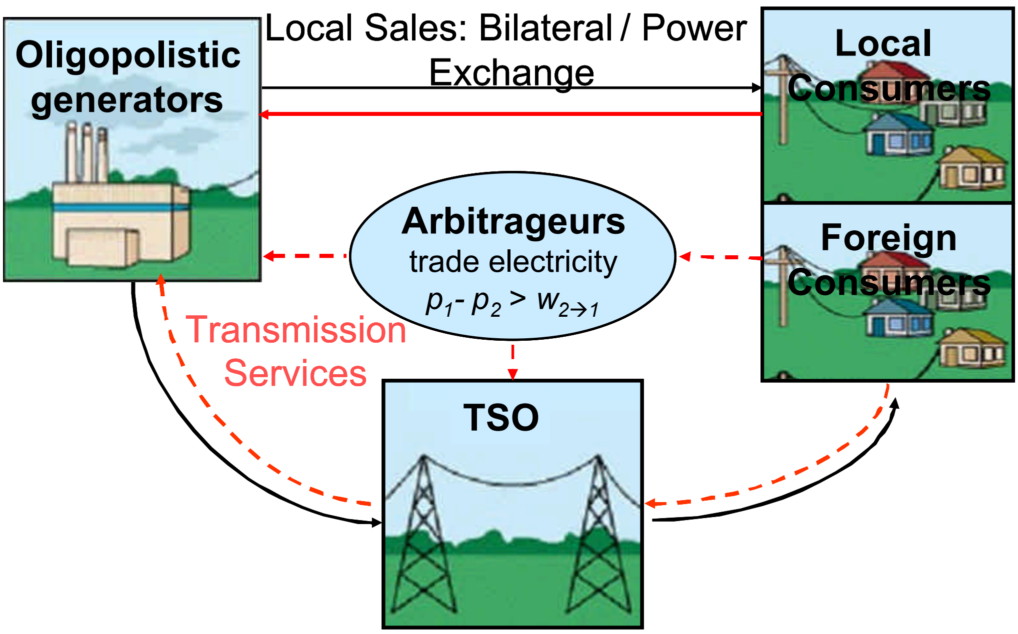

Figure A.8 *Market structure in COMPETES*

Appendix B The CBA study of Fraunhofer ISI *et al.* on the expansion of energy from renewable sources in Germany

B.1 Introduction

March 2010 Fraunhofer ISI and partner institutes have published an interim partial cost-benefit analysis of the EEG (Breitschof, et al., 2010a). A study update has been released in June 2010 (Breitschof, et al., 2010b). The cost-benefit analysis concerned considers social costs and benefits and distributive effects of the EEG for specific stakeholder groups. This study is the first major report submitted by the ongoing large multi-year project concerning the assessment of social costs and benefits of the EEG. This project is commissioned by BMU, the German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety. Cost and benefit effects are categorised as follows:

1. Direct and indirect *system costs/benefits*. These costs and benefits the expansion of renewables in Germany relate to the power (generation and T&D) system including social costs and benefits not or inadequately accounted for by prevailing market prices.
2. *Distributional aspects*. Which actors stand to lose and which others gain?
3. *Macroeconomic aspects*. Economic/employment impacts at macro or sector level, e.g. impacts on GDP, national/regional employment, etc.

The values are monetised to the extent possible for the actual situation (year 2008 and/or 2009 in the study update). Table B.1 below reproduces the main quantitative results as presented in (Breitschof, et al., 2010b).

We note that the two reports provide important inputs to a complete cost-benefit analysis, pertaining to specific years. In the cost-benefit analysis, due to be completed in the remainder of the project concerned, ex ante projections will be made of the future evolution of costs and benefits. A key benefit that still needs to be reported upon is the evolution of the dynamic efficiency of renewables expansion relative to competing non-renewable generation options. The expansion of renewables is poised to accelerate technological learning for a number of renewable technologies, if in a way that is surrounded by many uncertainties.

In the subsequent brief review of the methodology that led to the results shown in Table B.1 below, we will focus on the items regarding renewable electricity that matter significantly for the cost-benefit analysis of the present study. The following items will be discussed below:

- Avoided environmental damages (RES-E).
- Balancing costs (EEG power).
- Network reinforcement (EEG power).
- Transaction costs (EEG power).
- Merit-order effect (EEG power).
- Macro-economic and sectoral aspects (RES total).

Table B.1 *Overview of main quantitative results of the study by Fraunhofer ISI et al. on the costs and benefits, distributive and other effects of the deployment of renewables in the German electricity and heating market , 2008 and 2009*

Effect item	Effect type	Focus of effect analysis	Value in € million (unless indicated otherwise)	Value in € million (unless indicated otherwise)
Category A: System-analytical cost and benefit aspects			2009	2008
Avoided emissions	Avoided costs	RES-E	5700	5900
		RES-H	2100	2000
		RES total	7800	7900
Balancing costs	Indirect costs	EEG power	335 - 385 1)	595
Network reinforcement	Indirect costs	EEG power	20 - 40	20 - 40
Transaction costs	Indirect costs	EEG power	30	30
Differential costs heat	Direct costs	MAP heat	522	432
		RES heat	1472	1028
Differential costs power (incl. cost CO_2 allowances)	Direct cost	EE power	5590	4323
Category B: distributional aspects			2009	2008
Differential costs power	Burden on power user	EEG power	4600	4650
Merit-order effect	Cost relief	EEG power	n.a.	3580 - 4040
Special cost allocation rules	Relief to certain companies	EEG power	660	720
Tax on EEG power	Burden on power user	EEG power	1000 - 1133	930 - 1106
Public and private stimulation	Burden on public bodies / relief of plant operators	RES total	791	445
		RES research	277	161
		RES deployment	513	284
Category C: Macro-economic and sectoral aspects			2009	2008
Employment and sales revenues	Sales revenues	RES total	16100	14650
	Employment		300500 persons	278000 persons
Avoided energy imports	Import value	RES total	5100	6600

1) Preliminary estimates
Source: (Breitschof, et al., 2010a)

B.2 Avoided emissions

The most important social benefit category, as indicated by the report under review, is avoided emissions, which are valued *for renewable electricity* at € 5.7 billion and € 5.9 billion in 2008 and 2009 respectively. The lion's share contributed to this amount - dwarfing the partially offsetting (positive and negative) contributions of non-GHG pollutant emission - is estimated CO_2 emissions avoided. This is brought about by substitution of power from non-renewable sources (notably fossil fuels coal and natural gas) by RES power. The quoted aggregate amount is based on complex modelling efforts to estimate avoided emissions quantities as well as 'best guestimates' of social damages that would have resulted from the avoided emissions. These emissions would have occurred in a counterfactual non-RES-E baseline.

A lot of major studies have been consecrated to the valuation of GHG emissions damages. Based on some eminent studies, e.g. those of the EU co-funded EXTERN-E and NEEDS projects, the BMU study has put a value of $ 70 / t CO_2 emissions. In our view any marginal damages value considered over a long term time frame is subject to extreme uncertainty. It very much depends on quite uncertain climatic impacts of GHG emissions, global trends regarding population and per capita economic growth, electrification of energy services, the intensity of public command and control measures regarding implementation of energy efficiency and conservation and associated social behaviour, as well as last but not least resource scarcity trends across the fuels and materials supply chains. For example, *unanticipated* very strong tendencies towards electrification, technological progress towards 'dematerialisation', stringent fuels and materials supply chain scarcities, and demographic dynamics towards a stabilising and consequent declining world population may render current guestimates of environmental damages gross overshoots on hindsight, whilst unanticipated opposing trends may render current guestimates far too low. On current, quite imperfect knowledge, the \$ 70 / t CO_2 valuation as such for environmental damages caused by GHG emissions would seem acceptable.

Another issue is, whether it is appropriate to apply this valuation to credit RES-E expansion for emissions avoided relative to a counterfactual non-RES power scenario. A very essential presumption is that the public sector at the EU and German level has mandatory set emissions targets that fully integrate ex ante the presumably correctly anticipated impacts of national renewables market stimulation measures in the EU member states, such as notably the EEG in Germany. Although a question mark can be put in this respect for the 2008-2012 GHG emissions targets, we consider this presumption as *grosso modo* fair. Yet key consideration in the target setting is the consideration of the political urgency to mitigate climate change. Given binding targets set at the EU level for the EU ETS sector and at the national level for the non-EU ETS sector, expansion of renewable electricity in Germany will trigger GHG emissions elsewhere in the EU. Hence, in this way attributing GHG emissions avoided quantities avoided to policies in the domain of renewables stimulation boils down to double counting. In fact, dedicated renewables stimulation policies should be based on other arguments such as dynamic efficiency improvement in power generation and supply security. GHG mitigation policies and measures such as the EU ETS provide a generic support to low carbon generation technologies such as notably RES-E technologies. In fact, GHG emissions in the EU ETS sector come at the cost of the applicable number of GHG emission permits, which currently trade at some € 14-16 / tCO_2. Hence, at least to some extent GHG emissions have been internalised.

B.3 Differential costs of EEG stimulation of RES-E power

The calculation of the differential cost of EEG power with respect to the counterfactual 'no-EEG' baseline scenario is not so easy as it would seem. Two main approaches are presented in the BMU studies (Breitschof, et al., 2010a and 2010b):

- *The 'system-analytical differential costs approach'*. For each RES-E and conventional power category the levelised cost of electricity (LCOE) are projected. For each RES-E category the portfolio mix of non-RES power this RES-E category replaces, is projected. If e.g. 1 MWh PV power is projected to replace 0.3 MWh gas-based GTCC (combined cycle gas turbine) power and 0.7 MWh hard-coal based PCC (pulverised coal combustion) power, then the respective substitution coefficients and the respective LCOE of PV power, CTCC power and PCC power determine the differential cost per unit of power for PV.
- *The 'EEG cost burden for power end users' approach.* The average base load wholesale market price is deducted from the average EEG preferential tariff. The resulting price difference is multiplied by the annual EEG power volume. Challenges are to define an acceptable benchmark for the base load wholesale market price and how to account for the merit-order effect as well as for profile factors (time profiles of technology-specific RES-E power injections). We revert to the merit-order effect further down below.

The BMU study has applied the first approach from a societal perspective. This is justifiable to the extent that the research question is answered how much is the additional social cost of renewables with respect to a 100% conventional power baseline scenario. For the purposes of the present study, we are interested for the purposes of the present study in the incremental social cost of EEG power. The cost figures of the BMU study presented in Table B.1 above are lower than the incremental EEG costs as e.g. the *negative* incremental social cost of power generated by large hydro plants (that are not stimulated by the EEG) are included in the consolidated RES-E figures in Table B.1 above.

B.4 The merit order effect

With the possible exception biomass-based generation, renewable-based generation technologies have typically characterised by high capital costs and low fuel and other variable Operation & Maintenance costs as compared to power from conventional power plants. The short run marginal cost of RES-E makes that expansion of installed RES-E capacity tends to reduce *on average* the hourly demand for power from conventional non-RES power plants. This tendency is reinforced by currently prevailing RES-E stimulation schemes, such as notably but not only the German EEG. On the other hand, intermittent RES-E power sources such as notably wind power and less so solar PV make for highly volatile residual demand from conventional sources and a large demand for balancing and network transport service capacity. In this sub-section we focus on the effect of RES-E on the average hourly wholesale power price.

The merit order in dispatching power plants tends to be based on the (ascending) sequence of short-run marginal generation cost. Given the typically higher cost of non-RES power plants, the latter determine the evolution of wholesale power prices. When we concentrate on the power supply by non-RES power plants, expansion of RES-E capacity will tend to reduce the deployment intensity of existing conventional capacity. Notably at hours when large injections of RES-E occur (e.g. at windy hours) the conventional plants with the highest short-term marginal costs will ramp down and be switched off the first. Especially when the power supply curve for conventional power plants is steep in the 'marginal power plants area', such injections can very much depress hourly power prices on the wholesale market. A number of studies *inter alia* (Sensfuß and Ragwitz, 2007 and 2008) have empirically proven this downward price effect, called the merit order effect. Based on the empirically estimated downward effect, the BMU establishes an average merit order effect per MWh supplied on the wholesale market. This effect might *ceteris paribus* be a welfare enhancing, to the extent that additional 'consumer surplus' of German power users would dominate the decrease in 'producer surplus' facing generators. Not only household consumers might spend more because of a lower electricity bill but also the competitive position of the electricity-intensive industry would improve.

This reasoning is in for some qualification. In fact, a major part of this effect is distributional rather than aggregate welfare rising in nature. The increase in the consumer surplus, social benefits for power end-users, is for a large part offset by the decrease in so-called producer surplus: i.e. the reduction in aggregate value added by conventional power producers and RES-based power producers that are not protected by preferential EEG-mandated feed-in tariffs (e.g. large hydro plant operators). An even more serious issue is that the public intervention by way of RES-E production tariffs on top of market prices, especially for power that is included in power injection surges from intermittent renewable sources will strongly negatively affect the investment climate for power operators using plants that are not shielded from the 'merit order effect' by EEG-mandated preferential tariffs. In the course of a few years this strongly adverse effect on the investment climate for non-EEG-shielded producers is poised to translate itself into a reduced propensity to invest. In turn, this results in higher required rates of return (hence higher costs) for investment in power generation. Put differently, the declining demand for non-EEG power will be followed with some time lag by declining aggregate supply capacity of non-EEG power plants (scrapping of capacity of existing non-EEG power plants exceeding capacity additions by new non-EEG plants). *The wholesale power price evolution resulting from these opposing effects are ambiguous.*

Among others, the (Breitschof, et al., 2010a) study retorts that the second (power price rising) effect has not been proven empirically so far. In our view this argument does not at all refute the occurrence of the second effect. To decipher it from power price statistics is a hard task as power prices result form a very complex interplay of factors. Even so, we like to point out that the power markets in North-Western Europe are recovering from an enormous investment dip in conventional generation, following the liberalisation drive over the last 10-15 years.[44] The average power prices to date, even in spite of the financial crisis and the current natural gas oversupply situation, is a multiple of those prevailing around the year 2000. Moreover because of ongoing liberalisation in tandem with massive investments in interconnectors and institutional market integration, this is a quite strategic time for the few remaining big well-capitalised 'national champion' players on the North-Western European market, such as E.ON, EdF, RWE and Vattenfall to grab - with tacit strong support from their respective 'home' governments − market share as soon as possible through mergers & acquisitions and quasi-foreclosure through massive new investments in new generating capacity. Currently the tri-lateral FR-BE-NL market coupling is on the verge of becoming a penta-lateral GE-FR-NL-BE-LU market with further market integration with the Nordic countries[45], and perhaps the UK, following soon. Yet, it is a matter of (limited) time that the negative 'merit order effect' on the investment climate for conventional power supply will dominate the tapering-off positive effect of the backlog in power supply investments and strategic investments in the wake of the liberalisation drive and ongoing regional market integration.

Given the ambiguity of the mid/long-term merit order effect on average prices in the wholesale market as against the empirically established short-term merit order effect, it would occur to us that refraining from imputing (positive or negative) welfare impacts is the most acceptable valuation procedure. Any remaining average wholesale price reducing effect in the real world is hardly to be realistically simulated by any complex power market model. Moreover, the negative welfare effect of increasing market price volatility as a result of public support for market deployment of intermittent renewable ought to be accounted for as well.

B.5 Power system balancing costs for fluctuating EEG power injections

The BMU-commissioned study under review describes the situation regarding the costs made for reliably accommodating fluctuating EEG power injections before the introduction of the regulation in force since early year 2010, '*AusglmechV'* (see Sub-section 4.2.1 above). The following cost categories are distinguished (Breitschof, et al., 2010a):

1. Imbalance costs associated with wind power injections deviating from notifications. For year 2007 these costs are estimated at €210 million.
2. Capacity availability fees to be incurred for dedicated reserve capacity contracted by the TSOs to accommodate the reliable absorption of wind power. For year 2007 these costs are estimated at €75 million.
3. Costs related to the monthly base load bands of EEG power assembled by the TSOs with imbalance risks for intermediary power traders and power suppliers (pre- *AusglmechV* situation. These costs broadly refer to the profile cost including the so-called merit-order effect (See Section B.4 above). For year 2007 these costs are estimated at €160 million.
4. Other related costs. These might include redispatch activities occasioned by integration of notably wind power. For year 2007 these costs are estimated at €125 million.

In year 2007, 67.1 TWh of EEG power was fed into the German networks, of which 39.1 TWh of wind power. Based on these figure, Table 3.3 below is compiled.

---

[44] Just before the liberalisation era a large overcapacity had been accumulated over the years, the cost of which could then be readily passed on to the end-users.

[45] Meanwhile, the Central-West European Market Coupling (CWE MC) and the CWE-Nordic Interim Tight Volume Coupling (ITVC) has been announced to be effective as from November 9, 2010.

Table B.2 *Power system balancing costs for fluctuating EEG power injections according to a recent BMU-commissioned study, year 2007*

Cost cat.	Description	[mln €]	EEG power [€ /MWh]	wind power [€ /MWh$_{windpower}$][1]
1	Imbalance cost wind power	210	3.1	4.3
2	Reserves for wind power	75	1.1	1.9
3	EEG power banding	160	2.4	3.3
4	Other costs	75	1.9	3.2
	Total		8.5	11.7

[1] Assuming 80% of the total EEG power integration costs relate to wind power except for wind reserves: 100%.
Source: (Breitschof, et al., 2010a: p. 83, Table 4.5)

The new *AusglmechV* regulation is expected to yield significant cost reductions. It seems that the reserves for wind power can be fully eliminated. Furthermore we remark that the EEG power band assembling cost refer *grosso modo* to the profile cost including the merit order effect.

Some further cost reductions in balancing costs might be realised in the coming years considering factors such as:
- Improving wind power forecasting capabilities
- The portfolio effect, to be realised by aggregators of renewable and distributed energy resources, leading to lower aggregate imbalance positions.

On the other hand, *ceteris paribus* higher penetration of intermittent renewable generation might lead to higher price volatility including volatility of balancing energy prices. This may raise unit balancing cost notably for wind power generators. Holttinen *et al.*(2008) suggests on the basis of a profound review of wind power integration studies that balancing costs for wind power may run from approximately 1 €/MWh in networks with low wind power penetration to about 4 €/MWh in high wind power penetration networks.

We note that the German Network Regulatory Agency in its annual monitoring report of year 2009 mentions EEG balancing costs totalling €577 million in year 2007 and €595 million in year 2008 respectively without further cost details (Bundesnetzagentur, 2009: p. 43). The latter figure is also presented in (Breitschof, et al., 2010b) as reproduced in Table B.2 above. Tentative estimates without further details suggest that the power system balancing cost on account of integration of EEG power have come down in 2009 to a level in the €335-385 million interval (Breitschof, et al., 2010b). In general, due to improving wind power forecasting capabilities the cost per MWh of wind power are poised to come down. Also the direct marketing of EEG power under the *AusglmechV* regulation may help to improve the efficiency of balancing wind power. On the other hand, transaction costs for the TSOs to handle the ultimate pass-through of these marketing costs to electricity end-users will go up on account of *AusglmechV*. Furthermore, unlike e.g. the SDE feed-in system in the Netherlands, also the most recent EEG reforms have not yet introduced cost-reflectivity to wind power generators.

In this respect it is in order to mention that Fraunhofer ISI has proposed a noteworthy reform to the prevailing EEG. This institute proposes to introduce an optional 'gliding' feed-in premium, broadly akin to the current Spanish system (Sensfuss and Ragwitz, 2009). The proposal concerned envisages providing EEG-support-eligible generators the choice between currently prevailing feed-in tariffs and feed-in premiums with introduction of balancing responsibility for generators of EEG power choosing the latter option. Adoption of this proposal would further increase the visible part of the total EEG cost to German society. E.g. a numerical example in the proposal document indicates that - in year 2007, at a commodity base load price on the wholesale power market to the tune of **50,8 €/MWh** and an EEG feed-in tariff of **83,6 €/MWh** and a (notional) optional feed-in premium of **40,04 €/MWh** for (onshore) wind power − with wind power operators opting for the proposed alternative option the visible cost to German society would rise by **7,24 €/MWh**, compared to the going EEG tariff in the pre-*AusglmechV* situation (Sensfuss and Ragwitz, 2009: 12). Sensfuss and Ragwitz derive the notional premium of **40,04 €/MWh** for wind power as follows.

- Based on empirical analysis, they derive a 'profile factor' for wind power in Germany during years 2006 and 2007 of 89% and 88% respectively. This means that e.g. in year 2007 on average the market revenues per MWh of wind power was 88% of the average market price for base load on the wholesale market. This 12% negative deviation from the average market price is brought about by two factors: (i) *on average*, wind power is injected at hours with relatively low market prices and (ii) the merit order effect: *ceteris paribus*[46], injections of wind power drive down market prices. A somewhat lower **profile factor**, i.e. **85%**, for calculating the proposed feed-in premium is proposed to incentivise the choice for the feed-in premium option.[47]
- RES-E operators opting for the feed-in option have to assume responsibility to market the power they produce. This responsibility will entail administrative costs, such as procuring and operating IT systems for power trading. For less controllable power sources, such as wind power, Sensfuss and Ragwitz (2009) propose a fixed **trading cost allowance** of **3 €/MWh** is proposed.
- RES-E operators opting for the feed-in option have to assume (directly or indirectly through a balancing responsible party willing to absorb the balancing risk) responsibility for notifying the TSO of their power injection plans and for the cost of deviating from their notifications. This responsibility will entail for a wind power operator that he (or his designated balancing responsible party) will have to bear the opportunity costs charged by the TSO for arranging system balancing. The opportunity costs charged by the TSO for ramping up or down system generation and/or load relative to the market price will be relatively high at time periods when the imbalance position of the wind power operator is in the same direction as the (near) real time aggregate imbalance position of the whole electricity system in the TSO control area. Sensfuss and Ragwitz (2009) propose for wind power generators an **imbalance cost factor** (*Fahrplanerfüllungsfactor*) of **20%**.

The proposed feed-in premium can be calculated as follows (Sensfuss and Ragwitz, 2009: 10):

$$\boldsymbol{P = S - F.N + H + R.N} \qquad \text{(B.1)}$$

,where:
P : EEG feed-in premium
S : EEG feed-in tariff for the same RES-E technology category
F : profile factor
N : realised average monthly base load price (as calculated *ex post*)
H : trading cost allowance
R : imbalance cost factor
Including the necessary incentive to assume commodity price and balancing risk, the average wind power operators would be close to indifferent between the prevailing feed-in tariff option and the proposed feed-in premium option. In the 'case study' described above, equation B.1 works out as follows (in €/MWh):

$$\boldsymbol{P = 83.6 - 0.85 * 50.8 + 3 + 0.20 * 50.8 = 40.04}$$

The example above boils down to feed-in premium base price of (50.8+40.04=) **90,84 €/MWh**. For comparison, the feed-in premium base price in the Dutch SDE for onshore wind installations commissioned in 2010 is 96 €/MWh, but guaranteed for a shorter period than in Germany.

46 Without regard to the ensuing (negative) impact on the propensity to invest in new non-EEG-eligible generating capacity.

47 Because of the expected increasing market penetration of wind power, the merit order effect is expected to become stronger. Consequently, Sensfuss and Ragwitz suggest to reduce the approved profile factor by 0.75% per annum which would yield for wind onshore in year 2010 a profile factor of 82%.

B.6 Network reinforcement costs

In accommodating rapid expansion of intermittent renewable electricity including notably wind power whilst ensuring compliance with prevailing power reliability and quality standards, network operators need to incur significant incremental amounts in network reinforcement and operations compared to a counterfactual baseline where the additional power concerned would be generated completely from non-EEG sources. This goes the more so when additional wind power capacity tends to be installed in a concentrated fashion remotely from load centres, such as in northern Germany. The studies under review account for a mere € 20-40 millions per annum in reinforcement of German transmission networks. As credible assessment of such costs warrant complex load flow modelling we are not in a position to redo these calculations. Nonetheless we suspect that the true incremental transmission network costs engendered by stimulation of renewable electricity by the EEG are significantly higher. In this respect, we note that the actual expansion of the German transmission network falls seriously short with what DENA has identified as necessary to accommodate the expansion of wind power capacity (Stratmann, 2010). What is more, the incremental reinforcement costs on distribution networks ought to be accounted for as well. Quantification thereof is very much dependent on e.g. local topology of distribution networks and consequently extremely complex.

B.7 Transaction costs

Report (Breitschof, et al., 2010a) contends itself with the quantification of 'transaction costs' in the domains of renewable electricity and renewable heating and cooling. Transaction costs would have to encompass all costs that are directly related to the transactions considered, e.g. the selling and buying of certain forms of fuel/electricity from renewable sources. Such costs include search and information acquisition costs, negotiation and decision costs, supervision and realisation costs (Breitschof, et al., 2010a: p.106). Moreover the 'bureaucracy costs' (deadweight red tape cost) of collecting, keeping, providing mandatory data or other information is to be included in transaction costs. In the *AusglmechV* situation to date, the following actors are affected:

- Distribution system operators (DSOs), mandated to absorb EEG power and to pay EEG beneficiaries the applicable EEG tariffs;
- Transmission system operators (TSOs), mandated to reimburse the DSOs for EEG cash outflows and to assume responsibility to transact EEG power on the power exchange with the associated imbalance price and volume risk and to equalise associated EEG costs among themselves (see Sub-section 4.2.1 above). In the study reference years 2008 and 2009 (Breitschof, et al., 2010b) and preceding years, the transaction costs of these actors were lower: imbalance risk because of EEG power uptake was passed on to power traders and suppliers. On the other hand ex post accumulated imbalance results for those years are less settled through annual revisions of the EEG surcharge. The pre- *AusglmechV* deadweight administrative cost for the TSOs related to assembling monthly EEG base load bands have been replaced by costs to administer the EEG cash flows fund for the TSO control areas;
- Power suppliers and traders on their behalf. To date, their main administrative costs is to pass on the EEG surcharge to their end-users and to pass on the surcharge revenues to the TSO of the control area, where their customers are located; in the study reference years 2008 and 2009 and in prior years the transaction costs of these actors were much higher than to date as a result of the change in the cost equalisation procedures induced by the new *AusglmechV* regulation (imbalance volume and price risk; administrative cost related to mandatory provision of piles of data).

The (Breitschof, et al., 2010a and 2010b) reports put the annual transaction costs for system operators on the order of €30 mln (Breitschof et al., 2010a: p.113 and Table B.1 above) or approximately 0.4 €/MWh of EEG power. We are not in a position to improve on this assessment but suspect that the true social costs in this regard are multiples higher. Furthermore, the transaction costs incurred by the public sector encompass costs of EEG adjustments/design, implementation, monitoring, enforcement and evaluation, publicity and public relations, etc. These (significant) social costs are disregarded. Therefore, it would appear defensible to state that alternative renewable electricity stimulation costs imply high deadweight cost in the public sector as well. Certain regulatory economists claim that, *in general*, regulation costs such as costs associated with rent seeking including free riding, design and implementation, and raising revenues tend to be grossly underestimated.[48]

B.8 Macroeconomic and sectoral effects

The shift in Germany from conventional to renewable electricity (and ongoing electrification of energy services previously performed on the basis of fossil fuel inputs) translate into less demand for fossil fuels on world/regional fuel markets. *Ceteris paribus,* this has a negative effect on the price evolution of fossil fuels, notably coal and natural gas. Subsequently, German fossil fuel users enjoy a positive consumer surplus effect. This may translate into secondary macroeconomic impulses to increase consumption levels and growth stimulation of the German economy as a corollary.

Germany is certainly not a completely negligible importer of fossil fuels. Yet on a global level Germany has rather little a waning (in the face of the formidable economic ascent of east and south Asia) monopsonistic market power. Moreover, rebound effects occur as fuel exporters are incentivised to further capitalise on their comparative advantage in fuel-resource-using development patterns and consumers in fuel importing countries might also become less prudent in economising on fossil fuel use. We would be inclined to be prudent with imputing significant welfare benefits in accounting for this energy price - GDP effect.

Without explicitly claiming macroeconomic benefits from the expansion of renewables in Germany, Breitschof *et al.* (2010a, 2010b) prominently depict the expansion of sales and employment in the renewables sector. Indeed, the figures presented are quite impressive. Yet they fall short of demonstrating positive net macroeconomic benefits. On the contrary, BMU statistics show a worrisome trend over the last decade of fast increasing average payments in terms of €ct/kWh (see Table 4.1 above) far above base load electricity prices. BMU forecasts for 2010 an average EEG payment of 14 €ct/kWh, with current EEX base load prices hovering around 5 €ct/kWh. This wide gap tentatively indicates a negative rather than a positive impact from the EEG to overall German GDP and employment *at present*.[49] Yet it stands to reason, that the gap between the unit cost of EEG-power cost and the base load power price will peak in the next few years, when the effects of 'technological learning' are poised to dominate the current cost-push factors of EEG power (increasing share of high-cost technologies in the EEG power mix, increasing penetration of EEG power in German power supply and increasing transparency on the total cost of EEG power). In fact, the most important benefit category to stimulate promising but currently not commercially mature RES-E technologies is dynamic efficiency. As already stated, this benefit still needs to be elaborated by the BMU-commissioned CBA study project.

Another important positive social welfare effect is the effect of the EEG on reduced dependence of the German economy on fossil fuels and the consequent improvement of long-term energy services security (Jansen and Seebregts, 2010). Yet it remains a great challenge as to how credibly and acceptably account for this important positive effect. The BMU study refers to some approaches to provide supply security indicators. Yet to our knowledge, attempts so far fall short of monetarily valorising the important long-term supply security benefit of the expansion of renewable in a comprehensive way.

---

48 See *inter alia* (Hahn, 2010) for elaboration of this issue and further references.

49 This tentative indication is strongly substantiated by a study prepared by RWI (Frondel *et al.*, 2009).