Efficiency and welfare distribution effects from the Norwegian-Swedish Tradable Green Certificates Market

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Executive Summary

Motivations underlying the research: Energy policies to increase renewable electricity production are widespread. Tradable green certificates are easily implemented compared with other policy instruments, since it is a market based policy scheme – the market decides certificate prices and where new renewable production is developed. Regional effects from these policies are poorly understood. Investments in new generation capacity are highly influenced by bottlenecks and limitations in the grid. Disregarding this relationship could prevent the best projects in a socio-economic cost perspective from being chosen in the market equilibrium.

The research performed: Three years of hourly consumption and price data from regional electricity markets are utilized to characterize the local electricity markets during season and day/night. An equilibrium model is developed and run to inspect market outcomes when the tradable green certificate scheme is introduced. A future scenario which include planned transmission investments is defined. A further scenario where local demand increase in addition to expanded transmission capacities is also defined. Welfare effects for old producers, new producers and consumers are calculated per region, as well as for the transmission system operator. The combined deadweight loss is calculated for each scenario.

Main conclusions: Increased supply of electricity leads to large welfare transfers. An unbalanced stimulation of the supply side produces substantial deadweight losses from the scheme. In order to reduce deadweight losses new supply should be combined with a) increased transmission capacities providing better market coupling or b) increased local demand. Localization of new renewable electricity production depends heavily on transmission behavior, and this affects the efficiency of the scheme. Regional prices may differ and produce large differences in welfare effects. This affects the national outcomes of the common Norwegian-Swedish tradable green certificate market, as well as the local outcomes for consumers and old producers. Densely populated regions have large deviations in net social welfare. Regional losers in scenarios with high export (introduction of the scheme and new cross-country cables towards North-European markets) turn into regional winners if local demand increase. Local resources are best exploited by an efficient grid, resulting in lower deadweight losses. Regional welfare differences are also evened out by an efficient grid with sufficient capacity. These benefits must be balanced against the costs of grid improvements.

Potential benefits: This research provides insights to firms who want to understand the consequences of the tradable certificate market, and for policy makers who shall construct new energy policies. If there is not a demand for new electricity supply, old producers will experience large profit losses, and the overall deadweight losses turn net social welfare effect negative. This may still be beneficial through crowding out fossil electricity production, but this is not the case in Norway and Sweden. Planned cables providing improved cross-border market coupling is an essential companion to the green certificates. Stimulation towards local use of the increased supply provides the best outcome, measured by net social welfare. If regional differences should be avoided, then the costs of grid capacity expansions need to be taken into account when evaluating potential energy policies.

Abstract

We investigate economic impacts of the Norwegian-Swedish Green Certificate Market, which promotes electricity produced from renewable energy sources. We formulate a mixed complementarity, multi-region, partial equilibrium model, clearing both the electricity and green certificate markets under perfect competition. The model applies an approximation of power flows in the transmission network imposing both Kirchhoff's current and voltage laws in a mixed complementarity formulation suitable for policy analysis.

The certificate scheme combines a subsidy to producers of renewable energy and a tax paid by consumers. The scheme increases the electricity supply and leads to welfare reallocation from old producers to new producers as well as consumers. The deadweight loss and welfare transfers are reduced when new interconnectors are built or new demand enters the system. We show how geographical distribution effects and locations of new production are affected by the representation of the internal network between the model regions.

Keywords: Renewable energy, Tradable green certificates, Equilibrium modeling, Cross-border electricity trade, Transmission

1 Introduction

This paper models the use of tradable green electricity certificates (TGC)[1] (MPE 2011) to support deployment of renewable electricity in the power market. Electrification is a driving force towards decarbonization of the energy system, and electricity demand is growing faster than all other final energy carriers (IEA 2014a). The power sector contributes more than any other sector to the reduction in the share of fossil fuels in the global energy mix (IEA 2014b). Many public support schemes have supported renewable electricity during the last decade, as a way forward to fight climate change, improve security of energy supply, promoting technological development and innovation, and providing opportunities for employment and regional development (EU 2009, REN21 2015). The main contribution of this paper is to combine a public support scheme for electricity production with a power market model with isoelastic demand in a capacitated transmission network with cross border energy exchange in order to study the Norwegian-Swedish green certificate market. We employ a deterministic partial equilibrium model to find the cost of reaching a target quota of renewable electricity production. It is formulated as a mixed complementarity, multi-region, partial equilibrium model. Both the electricity markets and the green certificate market are cleared under the assumption of perfect competition.

Our model is calibrated on empirical data from the Nordic power market, and finds an equilibrium solution that quantifies certificate prices in the common Norwegian-Swedish green certificate market as well as regional power prices, power production, demand and power flows through the grid. We study welfare distribution effects between different market participants and between different regions. Producers of new renewable electricity are compensated by green certificates, which they sell to suppliers. The certificate cost is carried further from suppliers to the customers through a certificate tax which affects demand and consumer surplus. The increased electricity supply impacts market prices on electricity, which affects existing producers.

A main reason behind the support scheme is the EU Renewable Energy Directive that defines legally binding targets for EU member's national renewable energy share (EU 2009). Policy instruments interferes with the market and will inevitably lead to deadweight losses in the short run market clearing. Market regulations are justified when they can alleviate market imperfections such as externalities, which prevent the market from optimal resource allocation in the long run and maximized welfare. In this case, burning fossil fuels that emit greenhouse gases today may have future societal costs that are not fully reflected in today's prices and not taken into account by market participants. In the case of the Norwegian-Swedish certificate

[1] Tradable green electricity certificates (TGC) are also known as Renewable Energy Certificates (REC), Renewable Energy Credits, Renewable Electricity Certificates or Tradable Renewable Certificates (TRC).

market, the political objective is to increase the renewable share in the energy mix. Our analysis is limited to study the effects of the certificate scheme in terms of welfare loss and distribution effects. We do not look at the long term positive effects or discuss if the suggested targets are justified by these. Still we investigate how two particular situations will change the observed effects: an increase in national demand for electricity and a capacity expansion in transmission to external markets. We do not discuss how these situations may occur or the costs of transmission expansion, but focus on how the certificate scheme affect the investments in generation capacities for renewables and the market clearing in these situations.

The most common policy instruments supporting renewable electricity today are feed-in tariffs, feed-in premiums, tradable green certificates and investment subsidies, possibly combined with tenders in various forms (Menanteau, Finon et al. 2003, Butler and Neuhoff 2008, Held, Ragwitz et al. 2014, Rosnes 2014). As of early 2015, 73 countries and 35 states/provinces had implemented price-driven feed-in policies, whereas 26 countries and 72 states/provinces had implemented quantity-driven quota policies (REN21 2015). Tariffs (fixed electricity prices) are decided politically, but the tariff may alternatively be offered as a premium above the prevailing market price of electricity. The feed-in premium is still a price-based support scheme, but the investor also gets exposed to the market price of electricity. This is desirable in terms of operational adaptations to the electricity market (Rosnes 2014). Tradeable green certificates operate in the opposite manner, a politically determined quantity induces a scarcity premium on renewable generation. The certificate price of renewable generation is formed in a separate certificate market (Morthorst 2000), and is not defined by a regulator. For each megawatt-hour (MWh) of renewable energy produced, a tradable “green" certificate is issued to the generator, who can then sell the certificate in the marketplace. The demand could be voluntary (based on preferences), or mandatory as a quota obligation on retailers or end-users (Nilsson and Sundqvist 2007). It is common to design the system as technology neutral in order to promote competition between technologies eligible for certificates, but the system can also be geared towards particular types of renewable energy (Coulon, Khazaei et al. 2015, El Kasmioui, Verbruggen et al. 2015). The investor is exposed to the certificate market in addition to the electricity market, making both electricity and certificate cash-flows uncertain. This should increase investment risk, and Jaraite and Kazukauskas (2013) report that firms operating under TGC schemes were more profitable compared to firms operating under feed-in tariff schemes. Feed-in tariffs have a longer track-record than green certificates, and feed-in tariffs will always be the least risky support scheme for the investor (Boomsma and Linnerud 2015).

From a regulator's perspective, a very attractive property of the tradable green certificate scheme is the potential to minimize the cost of a given quantity of renewable energy (Menanteau, Finon et al. 2003, Kildegaard 2008). Still Butler and Neuhoff (2008) find that German feed-in tariffs have had lower costs and larger deployment of wind power than comparable UK certificate schemes, while Haas, Resch et al. (2011) argue that technologyspecific feed-in-premiums have an advantage over green certificates the steeper the cost curve is, and that they are easier to implement and revise. The Swedish green certificate scheme is nonetheless reported as the most effective and efficient of all the schemes considered in their study[2]. Aune, Dalen et al. (2012) show that trade in green certificates can ensure a cost-effective distribution of renewable energy production, but differentiated national targets still prevent a cost-effective distribution of energy consumption across nations (such as in the EU). Pérez de Arce and Sauma (2016) compare four different incentive policies for renewable energy in an oligopolistic market with price-responsive demand. They find that the effectiveness of the different incentive schemes varies significantly depending on the market structure assumed. However, they use a simple network with only two nodes linked by one line where Kirchhoff's voltage law is not relevant. In recent years support instruments are increasingly used in various hybrid policies, especially in combination with competitive bidding (Held, Ragwitz et al. 2014, Couture, Jacobs et al. 2015, REN21 2015).

Both tradable green certificate scheme and feed-in policies are production subsidies, as opposed to investment subsidies such as investment support and low interest loans. We note that Rosnes (2014) compares operational efficiency under different support policies, and concludes that an inflexible power system should aim to introduce an investment subsidy instead of production subsidies as this does not distort the short term production decisions. In our paper we focus on welfare effects of the established tradable green certificate scheme, and leave further comparisons of support schemes for future research.

Currier and Sun (2014) study market power and welfare in electricity markets employing a tradable green certificate scheme. Instead of considering a deadweight loss from the scheme, they define a social welfare function including a damage function, and calculate welfare maximizing values of the tradable green certificates volume share (optimal renewables policy, ORP) under different market structures. Their work provides insights into the design of the scheme, while we take the TGC goal as a given volume as it is already politically decided. Instead of assuming a damage function in the design, we study the deadweight losses from the scheme. Currier and Sun (2014) do not consider a transmission network in their analysis, while we focus on the spatial properties of the grid that couples the Norwegian and Swedish electricity markets.

According to Oggioni, Smeers et al. (2012), market coupling is seen as the most advanced market design when restructuring the European electricity market. Tangeras (2015) predicts that electricity exporting countries will choose policies which increase electricity prices, and that a pursuit of domestic objectives distorts transmission investments and thereby market integration below the efficient level. Makkonen, Nilsson et al. (2015) find that national goals in transmission development contradict the Nordic capacity development targets, and conclude

[2] See Figure 10 on page 2192.

that national interests hinders socioeconomic cross-border network investments needed for market integration. Mirza and Bergland (2015) examine whether transmission bottlenecks are truly exogenous, and find that producers in southern Norway may exercise market power and be able to increase market price above marginal cost by inducing transmission congestion during late night and morning hours. These studies indicate that the transmission network is important studying developments of the power market and the green certificate market, and we will show its importance for analysing future welfare effects of the green certificate scheme.

Our model combines inclusion of transmission constraints and investments in renewables, as recommended by Munoz, Sauma et al. (2013). Exchange of energy between regions is represented with an underlying alternating current (AC) network approximated by a linearized DC network approximation (Schweppe, Caramanis, Tabors, and Bohn, 1988). To our knowledge this is the first empirical study using a model that combines an AC approximation of the transmission network with equilibrium modelling of support schemes and isoelastic demand for electricity. Empirical policy studies typically make the simplifying but unrealistic assumption that the physical AC network can be modelled as a DC network where the transmission systems operator (TSO) is able to decide transmission quantities individually (as in a network of tradable goods). Our analysis shows that the AC characteristics of the transmission network directly affects which projects are profitable. AC network properties reduce the flexibility of the grid, so when we include AC characteristics in the analysis, the location of new generation projects gets more important. Projects that are less profitable but have a favourable network location are preferred. This leads to higher certificate prices, and higher deadweight losses. Thus there is a trade-off between transmission network investments made by the TSO to avoid bottlenecks, and the efficiency of the support scheme for renewable power generation. We refer to Helgesen and Tomasgard (2016) for a list of related studies and a further discussion of the importance of modelling the AC characteristics of the transmission network.

International electricity markets have been liberalized and redesigned during the last three decades. Norway was one of the earliest countries, deregulating the electricity market in 1991 (Bye and Hope 2007). Many studies since then have focused on market competition and possible misuse of market power (Borenstein, Bushnell et al. 1995, Borenstein and Bushnell 1999, Bushnell 2003). Although many policies have been implemented to promote competition, there is still evidence of market power in electricity markets (Bushnell, Mansur et al. 2008, Dahlan, Kirschen et al. 2012, Mirza and Bergland 2015, Pérez de Arce and Sauma 2016).

On the other hand Neuhoff (2003) argues that a system where the system operators integrate national energy spot markets and transmission planning is helpful in mitigating the extent of market power being exercised. Amundsen and Bergman (2007) conclude that the Nordic countries have created an integrated wholesale market that dilutes market power that otherwise would have been a feature of each of the national markets. Amundsen and Bergman (2012) also study to what extent market power on a tradable green certificate market can be used to affect an entire electricity market, and conclude that Swedish producers could exercise market power using the national TGC-market, but that this problem is eliminated by opening the TGC-market for other Nordic countries (which is the current situation).

In this paper we assume perfect competition in the electricity and tradable green certificate markets. In Helgesen and Tomasgard (2016) we presented a similar model for imperfect competition and linear demand, and solve the equilibrium problem consisting of each player's Karush-Kuhn-Tucker (KKT) conditions together with market clearing conditions to obtain a generalized Nash equilibrium. The approach was demonstrated for stylized cases. The main contribution of this paper compared to Helgesen and Tomasgard (2016) is the empirical study and identifying the welfare and distribution effects. As compared to the previous paper where we used a linear demand function, we also make more realistic market assumptions using iso-elastic electricity demand as in Böhringer, Hoffmann et al. (2007).

The remainder of this paper is organized as follows: Section 2 provides a brief summary of the Swedish-Norwegian green certificate market promoting renewable energy in electricity production. Section 3 describes our mathematical model and the data underlying our quantitative analysis. Section 4 presents the analysis case, section 5 discusses the results and section 6 concludes. An appendix shows how the complementarity model is formed from each player"s optimization problem.

2 The Norwegian-Swedish Tradable Green Certificate Market

The common Norwegian-Swedish market for electricity certificates was established on January 1st 2012, nine years after Sweden first introduced their domestic market for tradable green certificates in 2003. In 2012 Norway and Sweden decided to share a combined goal of establishing 26.4 TWh new electricity production based on renewable energy by 2020. This increase amounts to about 10% of the production before the scheme. Norway and Sweden were each responsible for financing 13.2 TWh in the certificate system, regardless of the amount of production that is located in each of the two countries. The contractual commitment for each country was to redeem 198 million certificates by 2035 (198 million certificates amounts to 198 TWh corresponding to 13.2 TWh over 15 years). In 2015 Sweden decided to raise its ambition, and increase the common goal from 26.4 to 28.4 TWh of which Sweden will finance 15.2 TWh and Norway 13.2 TWh.

Producers receive one certificate per MWh renewable electricity that is generated for a period of 15 years. Electricity suppliers (and certain consumers) have a statutory duty to buy green certificates. Each country's total obligation is distributed as yearly quotas from 2012 to 2035. Each year the market participants with an obligation to buy green certificates must redeem certificates in order to fulfil their obligation according to the yearly quota. This creates the demand for green certificates. If a market participant cannot redeem the necessary certificates, he is charged a quota obligation fee that amounts to 150 per cent of the volume-weighted average price from the year of obligation.

Producers that receive certificates earn an income from selling certificates in addition to income from selling electricity. This makes it profitable for investors to invest in new electricity generation from renewable energy sources. The support scheme is technology neutral in the sense that all energy sources defined as renewable energy sources in accordance with Directive 2009/28/EC on the promotion of the use of energy from renewable sources (EU 2009) qualifies for the right to certificates (MPE 2012).

Since certificates are only assigned to new renewable production, this support scheme costs less than a subsidy provided to all existing producers would do. Thus the consumer tax that finances this scheme is lower. The downside is that old producers are hurt from the certificate scheme. The electricity certificates will establish additional power production, which will affect the electricity price. This may displace current producers, creating a crowding out effect in the electricity market.

A graphical example of consumer surplus change, producer surplus change, tax financing and deadweight losses is shown in Figure 1 below.

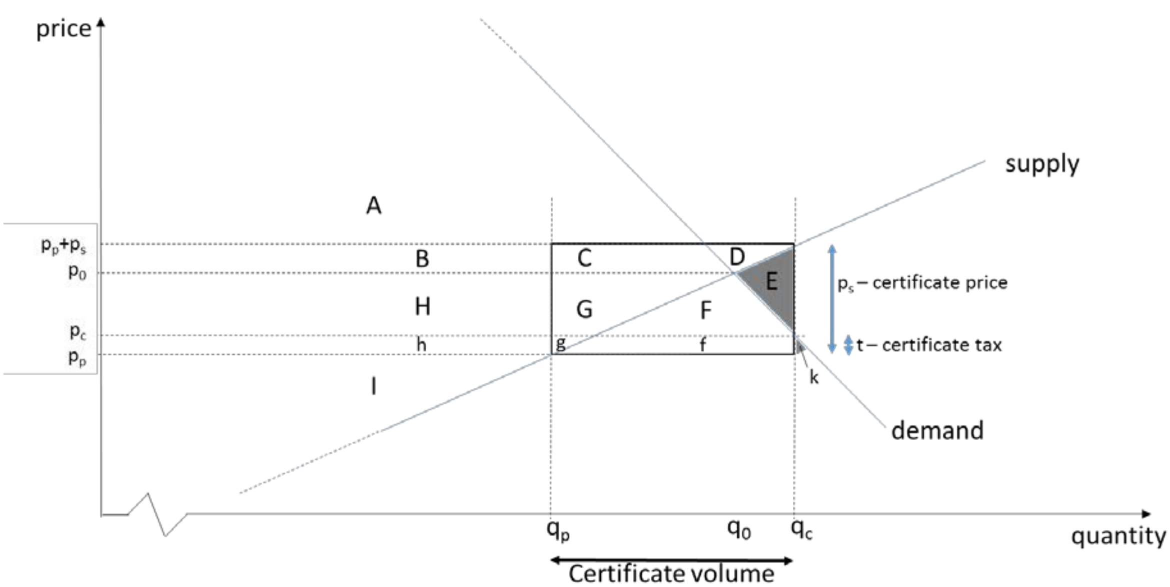

Figure 1 Welfare distribution effects from a certificate support scheme

The market solution before the green certificate scheme is introduced is found where supply q_0 meets demand at price p_0. The support scheme is going to establish new production by providing the necessary price markup for renewable electricity generation. In Figure 1 we notice that this new generation is crowding out parts of the old generation. The electricity price decreases to p_p, thus remaining old producers receive p_0- $p_p$less than before for each sold unit and reduce their generation to q_p. Renewable generation earns the new electricity price plus the certificate price (p_p+p_s). At this price they choose to produce exactly the target certificate volume of the support scheme. Total production increases from q_0 to $q_c = q_p + \textit{certificate volume}$.

Introducing a financial support scheme to remunerate expensive renewable power generation instead of cheaper (polluting) power generation implies that a welfare loss is imposed to society, unless the climate benefits of the scheme are quantified. Market regulations are justified when they can alleviate market imperfections such as externalities, which prevent the market from optimal resource allocation and maximized welfare. Burning fossil fuels that emit greenhouse gases today may have big future societal costs that are not reflected in today's prices and not taken into account by market participants. Our partial equilibrium model does not capture the benefits of the policy scheme, so introducing the scheme will inevitably result in a welfare loss. These losses are attributed to the policy instruments and are called deadweight losses. The deadweight loss from the green certificate scheme is represented in Figure 1 by the area marked E. In our analyses we investigate who bears these welfare losses. Of course, the motivation for the scheme is that the benefits for society when meeting the overall targets for the green certificate support scheme is higher that the welfare losses in the model. This we do not discuss or analyse.

The support scheme will cost-efficiently deliver new production to the market. Who will gain and who will lose? It is evident that ceteris paribus, the market solution in Figure 1 would imply a significant transfer from old producers (decreasing their producer surplus) to consumers (increasing their consumer surplus), while new producers earn a profit from the combined electricity and certificate income. The area in Figure 1 marked H represents the monetary amount that is shifted from old producer surplus to consumer surplus. The effects can be summarized in Table 1 while Figure 1 shows how the scheme is financed.

Consumer surplus before the scheme:	A + B + C							
Consumer surplus after the scheme:	A + B + C			+ F	+ G	+ **H**		
Producer surplus before the scheme:					G + g	+ **H**	+ h	+ I
Producer surplus after the scheme:		C + D			+ G + g			+ I
Monetary cost of the support scheme:		C + D	+ E	+ F + f	+ G + g			
Deadweight loss:			E					+ k

Table 1 Summarized effects of the welfare distribution.

A consumer tax is introduced as a markup on the producer price p_p, creating a wedge between producer price p_p and consumer price p_c. The tax is levied by the suppliers in order to cover the supplier's certificate costs and remunerate producers (possibly via brokers). We assume that competition or regulations prohibit suppliers to be overcompensated, thus the total tax amount (areas marked f+g+h in Figure 1) should be equal to the monetary cost of the support scheme (areas marked C+D+E+F+f+G+g in Figure 1). The green certificate tax incurs an additional deadweight loss to society, represented in Figure 1 by the triangular area marked k.

The consumer tax worsens the loss of old producers. Their total loss is represented by the areas marked G+H+g+h. New producers are not affected much by the tax, since they are compensated by the green certificate price. In Figure 1 consumers are gaining, but the net price effect for consumers is ambiguous. The tax is levied on a much larger volume than the green certificate quota, and the resulting tax could be smaller or larger than the decrease in producer price. Our results will show that both outcomes are possible.

We assume for simplicity in the figure that the tax applies to all consumers, but this does not have to be the case. Energy-intensive industries are for example exempt from this tax in Norway.

This graphical example illustrates some typical welfare distribution effects, but the example is simplified and we need a numerical model to handle a) Different technologies where only new renewable electricity production qualifies for green certificates. b) Dynamics through the year, since both the demand and supply curves change (independently) in different time periods. c) Trade flows between regions, which are affected by transmission capacities.

3 Mathematical model

Our partial equilibrium electricity model is used to analyse green certificate prices in a common transnational market characterized by several sub-regional markets (price areas) connected with several external markets. Green certificate prices are dependent of electricity prices, which have a more granular geographical dimension and a more granular time dimension (hourly prices).

Subnational area prices and transmission constraints are essential for assessing regional effects. We use a lossless approximation of an alternating current (AC) model focusing on real power with linear approximations of the power flow equations – the so-called "DC load flow" model (Schweppe, Caramanis et al. 1988).

We have *r* regions and *f* firms. There are *i* generation technologies available, and some of these are eligible for green certificates which are sold in a common market across Norwegian and Swedish regions. A variable levelized production cost is associated with each technology. Each firm can be located in several regions, and operate several technologies. Regions are connected by links with limited capacity. A transport cost and a transport tax is associated with each link.

We optimize social welfare assuming perfect competition and iso-elastic demand for electricity. Under the assumption of perfect competition there will be no arbitrage opportunities, since any price difference must be based on actual cost differences (Hobbs 2001). Thus we do not consider arbitrage in our model.

We assume that electricity supply is characterized by existing technologies' short-run marginal cost (SRMC), and by the levelized cost of electrity (LCOE) for technologies that require capacity investments. Renewable electricity generation receives tradable green certificates according to production volume. We assume that the certificate price is formed such that the combined income from electricity and green certificates covers the LCOE for the last capacity investment that fulfils the quota obligation. In the model description we just refer to marginal costs of production.

Our model is static in the sense that we consider a yearly quota and a certificate market in equilibrium. We assume that electricity suppliers choose to comply with the quota requirement, instead of paying a quota obligation penalty fee. (Compliance percentage has ranged from 99.95% to 99.99% in 2012-2015). We do not consider dynamic aspects such as banking or borrowing of certificates.

In our study we consider a representative year as our analysis period. We decompose this chosen period into time segments (as in standard capacity expansion models). We do this to capture the diverse operation of the system in different time segments. By splitting the year into timeslices, we can represent typical operating situations in the markets and the transportation network. Both demand and production potential varies over time, and the surrounding markets linked by grid connectors have different variation than the Nordic regions. Consumption, production and flow of power change significantly over the day, week and year.

By introducing timeslices, we also need to recognize the flexibility of hydropower from dammed water reservoirs. Hydro producers take into account the water value in their production decisions, which increases their marginal cost of production (Gebrekiros, Doorman et al. 2015). Norway and Sweden have considerable water reservoirs which enables producers to shift power generation between timeslices. We model this by allowing flexible production to exceed maximum average production by a factor f_i, while still restricting yearly production to the total yearly capacity G_{if}. Thus flexible production technologies may shift production between timeslices, but increased production in one timeslice necessarily means reduced production in one or more other timeslices.

The tax condition combines primal (s_{frt}, x_{ift}) and dual variables (μ, t_{μ}). Since both primal and dual variables are available in the complementarity format, we are able to formulate the tax constraint that finances the support scheme. Without this constraint, we could instead have formulated the max social welfare problem and solved the model as a nonlinear optimization model.

The formulation of the maximum social welfare problem as a mixed complementarity model with a tradable green certificate support scheme financed by a fixed consumer tax, timeslices and flexible production technologies is given below.

Sets

R	regions (we assume that each node represents a region), indexed by *r* and *k*
R_c	regions in the common market for tradable green certificates, indexed by *r*
I	generation technologies, indexed by *i*
I_c	generation technologies eligible for electricity certificates, indexed by *i*
F	electricity producing firms[3], each region is represented by one firm indexed by *f*
F_r	electricity producing firm in region *r*, indexed by *f*
N	loops in electricity network, indexed by *v*
K	lines in electricity network, indexed by (*r*, *k*)
K_v	lines in loop *v*, indexed by (*r*, *k*)
T	timeslices, indexed by *t*

Parameters

c_i	marginal cost of production for technology *i*
L_{rk}	transport capacity from region *r* to region *k*
R_{rk}	reactance on link from region *r* to region *k*
G_{if}	production capacity of technology *i* in region *f*
k_{rkv}	indicates if line from region r to region k is included in loopflow *v*, takes values *-1*, *0* or *1*
Q_{0rt}	reference demand in region *r* in timeslice *t*
P_{0rt}	reference price in region *r* in timeslice *t*
σ	own-price demand elasticity
V	green certificate volume
h_t	hours in timeslice t
H	total number of hours in analysis period
f_i	production flexibility technology i

Variables

[3] We do not need a firms index in a perfect competition model, but we choose to define a representative firm in each region to simplify interpretation of the variables and ease a model transition to multiple firms. The *f* index could alternatively represent a region.

s_{frt}	supply from firm *f* to region *r* in timeslice *t*
x_{ift}	production in region *f* using technology *i* in timeslice *t*
z_{rkt}	net flow from region *r* to region *k* in timeslice *t*
p_{rt}	supplier price of electricity in region *r* in timeslice *t*
w_{rt}	(dual) transport cost from the grid into region *r* in timeslice *t*
κ_{vt}	(dual) grid transport cost to impose Kirchhoff's voltage law in loop v in timeslice *t*
τ_{rkt}	(dual) price on grid transmission capacity from region *r* to region *k* in timeslice *t*
φ_{ift}	(dual) price on production capacity in region *f* and technology *i* in timeslice *t*
ω_{ft}	(dual) marginal income in region *f* in timeslice *t*
ψ_{ift}	(dual) price on production flexibility in region *f* and technology *i* in timeslice *t*
μ	price of tradable green certificate
t_{μ}	consumption tax rate to finance the green certificate support scheme

Producer conditions:

$$-p_{rt} + w_{rt} + \omega_{ft} \geq 0 \qquad \perp (s_{frt} \geq 0), \quad f\epsilon F, r\epsilon R, t\epsilon T \qquad (1)$$

$$c_i - w_{rt} + \varphi_{ift} + \psi_{if} - \omega_{ft} \qquad \geq 0 \qquad \perp (x_{ift} \geq 0), \quad i\epsilon I\backslash I_c, r\epsilon R, f\epsilon F_r, t\epsilon T \qquad (2a)$$

$$c_i - w_{rt} + \varphi_{ift} + \psi_{if} - \omega_{ft} - \mu \geq 0 \qquad \perp (x_{ift} \geq 0), \quad i\epsilon I_c \quad, r\epsilon R, f\epsilon F_r, t\epsilon T \qquad (2b)$$

$$\sum_{r\in R} s_{frt} - \sum_{i\in I} x_{ift} \leq 0 \qquad \perp \left(\omega_{ft} \geq 0\right), \quad f\epsilon F, t\epsilon T \qquad (3)$$

$$x_{ift} \leq G_{if} \frac{h_t}{H} f_i \qquad \perp \left(\varphi_{ift} \geq 0\right), \quad i\epsilon I, f\epsilon F, t\epsilon T \qquad (4)$$

$$\sum_t x_{ift} \leq G_{if} \qquad \perp \left(\psi_{if} \geq 0\right), \quad i\epsilon I, f\epsilon F \qquad (5)$$

TSO conditions:

$$w_{rt} - w_{kt} + \sum_v k_{rkv}\kappa_{vt} + \tau_{rkt} \geq 0 \qquad \perp (z_{rkt} \geq 0), \quad (r,k)\epsilon K, t\epsilon T \qquad (6)$$

$$\sum_{f\in F} s_{frt} - \sum_{f\in F_r}\sum_{i\in I} x_{ift} - \sum_{k\in R} z_{krt} + \sum_{k\in R} z_{rkt} = 0 \qquad , \quad w_{rt} \text{ free}, \quad r\epsilon R, t\epsilon T \qquad (7)$$

$$\sum_{(r,k)\in K_v} R_{rk}(z_{krt} - z_{rkt}) = 0 \qquad , \quad \kappa_{vt} \text{ free}, \quad v\epsilon N, t\epsilon T \qquad (8)$$

$$z_{rkt} \leq L_{rk} h_t \qquad \perp (\tau_{rkt} \geq 0), \quad (r,k)\epsilon K, t\epsilon T \qquad (9)$$

Market clearing condition:

$$P_{0rt}\left(\frac{\sum_{f\in F} s_{frt}}{Q_{0rt}}\right)^{-\frac{1}{\sigma}} - p_{rt} - t_{\mu} = 0 \qquad , \quad p_{rt} \text{ free}, \quad r\epsilon R, t\epsilon T \qquad (10)$$

Tax condition:

$$\sum_{t\in T}\sum_{r\in R}\sum_{f\in F} s_{frt}\, t_{\mu} \geq \sum_{t\in T}\sum_{f\in F}\sum_{i\in I_c} x_{ift}\mu \qquad \perp (t_{\mu} \geq 0) \qquad (11)$$

Green certificate constraint:

$$\sum_{i\in I_c}\sum_{f\in F}\sum_{t\in T} x_{ift} \geq V \qquad \perp (\mu \geq 0) \qquad (12)$$

The corresponding optimization problem for each player is given in the appendix.

Equation (1), (2a) and (2b) are the equilibrium conditions from the producer's decision variables s_{frt} and x_{ift}. Equation (3) states that the producer cannot supply more power than he produces (Supply constraint). Equation (4) allows flexible production technologies to shift production between timeslices (Flexlim constraint). Equation (5) constrains the yearly production to be within its production limits (Prodlim constraint).

Equation (6) is the equilibrium condition for the TSO's flow variables z_{rkt}. Equation (7) represents Kirchhoff's current law (KCL constraint), equation (8) represents Kirchhoff's voltage law (KVL constraint) and equation (9) constrains flows to be within the capacity of grid lines (Flowlim constraint).

Equation (10) represents the market clearing condition, such that supply equals demand in each market area and timeslice. Equation (11) assures that the consumption tax rate will finance the green certificates. Equation (12) represents the quantity obligation that regulating authorities have decided for the green certificates.

4 Analysis case

We analyze the effects of the green certificate scheme by comparing future scenarios just after 2021[4] with a base scenario that resembles the start of the development period for new renewable electricity production eligible for green electricity certificates. The base scenario defines the starting point for calculating welfare effects for consumers and existing producers. We define three future scenarios and compare four social welfare components against the base scenario. The four components are consumer surplus, profit from existing facilities, profit from new facilities and TSO profit from power flow wheeling fees.

Demand in the base scenario is met by production facilities existing before the green certificate scheme. In future scenarios we assume that new producers manage to cover their investment from their combined sales of electricity and green certificates. In order to invest, the producer must cover both production cost and investment cost – which we combine into the levelized cost of electricity. Electricity is priced such that existing suppliers cover their short-run marginal cost. Green certificates are priced such that new supply exactly reaches the quantity goal of the support scheme and also covers LCOE to the last (marginal) investor. A firm will not invest unless the electricity price plus the certificate price is equal to or higher than its levelized cost of electricity.

[4] Our future scenarios occur after 2021, because new facilities in Norway must be operational before 31st December 2021 to earn green certificates.

Our three future scenarios are constructed by cumulatively introducing

- the green certificate scheme (*elcert* case)
- new cables improving grid integration with Northern Europe (*cables* case)
- increased demand in Norway and Sweden (*demand* case)

The *elcert* scenario builds on the base scenario and forces new electricity supply from renewable energy sources reaching the common goal of 26.4 TWh yearly production in Norway and Sweden. The transmission network is expanded with increased cable capacity to Denmark (Skagerrak 4) which was operational in December 2014.

The *cables* scenario builds on *elcert* but takes into account planned new cables towards Germany and United Kingdom. These cables are expected to become operational in 2020 and 2021 respectively[5]. Norway and Sweden have flexible production and low electricity prices, while neighbouring countries are net importers of electrical power. These factors suggest that producers in Norway and Sweden would benefit from increased cross-border trade over the transmission network.

The third scenario is named *demand*, and builds on *elcert* and *cables.* In addition demand curves are shifted by increasing reference demand by 10% in Norwegian and Swedish price zones. We assume that the increased demand would be willing to pay up to three times the reference price P_{0rt}. This upper limit assumption is necessary in order to calculate the change in consumer surplus when the demand curve is shifted. (If we assume that the whole iso-elastic demand curve shifts, then the increase in consumer surplus would be infinite.) The motivation behind the *demand* scenario is that politicians might want to stimulate local demand instead of exporting electricity that have been subsidized by local consumers.

We run these scenarios on two different model versions:

- One simplified model assuming that the grid works as a transhipment network, without taking into account Kirchhoff's voltage law, and
- One version where Kirchhoff's voltage law is imposed on the grid.

If the grid was built with only DC lines it would behave like a transhipment network, while AC lines must adhere to Kirchhoff's voltage law. The actual grid is much more detailed than our aggregated network. It is too strict to assume that the grid adheres to Kirchhoff's voltage law at a highly aggregated level. On the other hand, it is too loose to assume that Kirchhoff's voltage law does not apply. We run our model with Kirchhoff's voltage law to inspect which type of effects that would be lost in a transhipment version of the model.

We define the scenarios listed in Table 1.

[5] The NordLink 1400 MW HVDC connection to Germany is expected to be operational in 2020, and the North Sea Network 1400 MW HVDC connection to UK in 2021.

Table 1 Scenarios

Scenario description	No Kirchhoff's voltage law	Kirchhoff's voltage law imposed
Base case	`Base`	`Base_kvl`
Green certificate scheme is introduced, increasing the amount of renewable electricity production in Norway and Sweden.	`Elcert`	`Elcert_kvl`
New cables towards Germany and United Kingdom are introduced, increasing the market integration (in addition to green certificate scheme).	`Cables`	`Cables_kvl`
Increased demand – 10% demand increase in Norway and Sweden (in addition to green certificate scheme and new cables)	`Demand`	`Demand_kvl`

4.1 Geographical coverage

Our model covers production and consumption in the 5 nodal price areas of Norway and 4 nodal price areas of Sweden. It also covers cross-border electricity exchange from Norway and Sweden to 8 other price areas (Finland, Denmark West, Denmark East, Germany, Poland, Netherlands, Russia, UK). The resulting network has 17 nodes and 24 arcs, of which 16 are AC lines and 8 are DC lines. The network is shown in Figure 2, in which AC lines are black and DC lines are yellow. The planned cables towards Germany and United Kingdom (included in the Cables and Demand scenarios) are indicated with dashed lines.

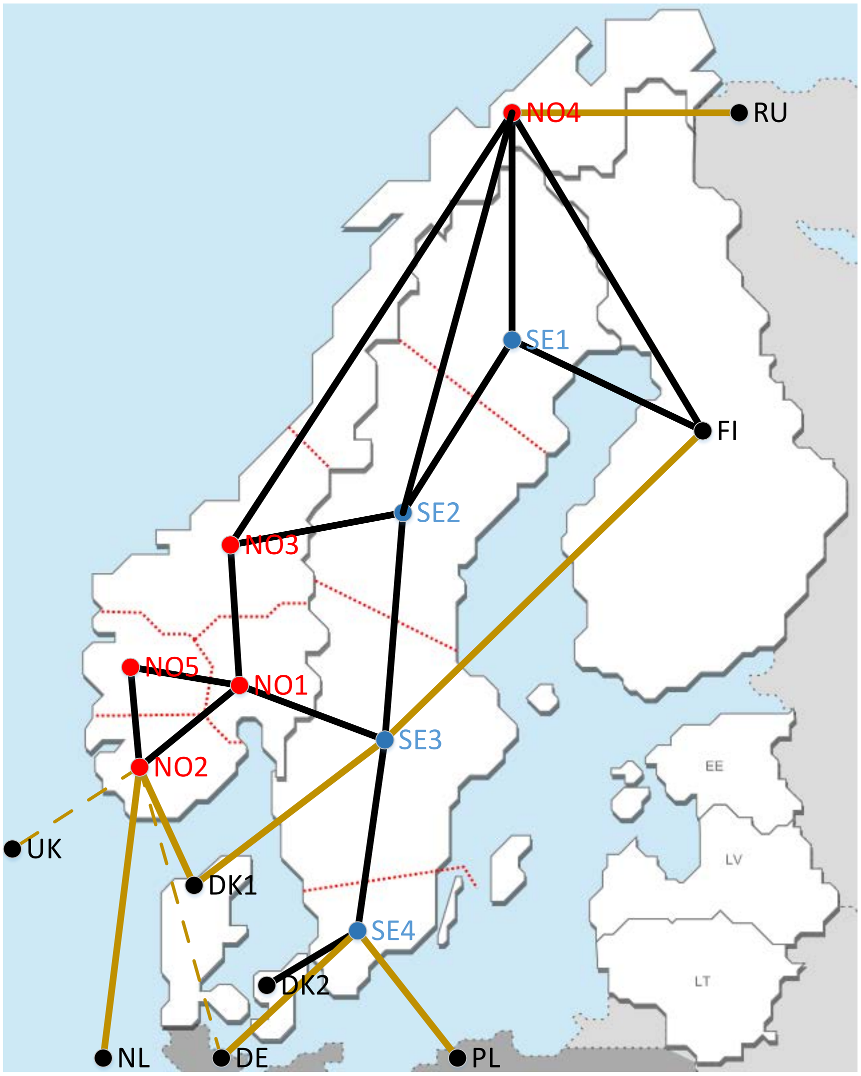

Figure 2 Transmission network. AC-lines in black, DC lines in yellow, planned lines are dashed.

12 nodes are connected in the AC network with 16 arcs. This gives rise to 16-12+1=5 cycles in the AC network.

4.2 Production technologies

Table 2 shows the power generation technologies included in the model, and their relevant SRMC and LCOE costs.

Table 2 Technology parameters

		SRMC [kNOK/GWh]	Investment (I) [kNOK/MW]	Fixed operating and maintenance (F) [kNOK/MW]	Lifetime (T) [years]	Availability factor (a) [share]	LRMC [EUR/GWh]	LCOE [EUR/GWh]
Existing	HYDREG0	5,00	1	1	40	0,95	0,64	0,65
	HYDROR0	6,00	1	1	40	0,95	0,77	0,78
	WIND0	10,00	1	1	20	0,32	1,30	1,31
	NUCLEAR0	50,00	1	1	40	0,82	6,27	6,28
	THERMAL0	250,00	1	1	25	0,94	31,27	31,27
Fossil	NGCC	518,00	6 300	160	25	0,86	75,63	79,07
	NG02CO2	521,00	13 071	360	25	0,86	88,17	95,45
	NG01	850,00	4 455	135	25	0,87	114,20	116,72
	NGPEAK_101	916,00	4 455	150	25	0,17	156,04	169,18
New hydro	HYDRUN04	12,00	10 800	85	40	0,60	19,82	31,23
	HYDRUN05	13,00	15 300	205	40	0,40	43,57	69,69
	HYDREG07	11,00	13 000	300	40	0,95	18,27	28,79
	HYDREG_101	14,00	17 500	420	40	0,95	24,74	39,05
	HYDRUN_101	15,00	15 000	180	40	0,50	34,17	54,29
	BIO	15,00	20 000	300	25	0,57	48,77	63,60
wind	WIND_on1SE	16,00	10 800	300	20	0,33	57,67	67,75
	WIND_on2SE	17,00	10 800	350	20	0,32	62,02	72,86
	WIND_on3SE	18,00	12 000	350	20	0,31	69,20	81,32
	WIND_offSE	19,00	20 970	350	20	0,42	81,03	95,27
	WIND_offNO	20,00	28 840	350	20	0,43	101,66	119,60
wind projects	W1A107N2	12,36	9 236	376	20	0,39	45,20	53,11
	W2A128N3	15,44	9 395	348	20	0,29	60,26	70,82
	W3A112N4	15,44	9 555	426	20	0,35	53,26	62,55
	W4A111N5	8,24	9 561	265	20	0,41	39,47	46,43
	W5A108N2	12,36	9 797	400	20	0,41	45,16	53,05
	...	...	...	...	...	...	...	...

Data sources: (Nohlgren, Svärd et al. 2014, Sidelnikova, Weir et al. 2015)

Data for 123 potential Norwegian wind power projects are included in the analysis, the source is (IFE/NVE 2014). The formulas for calculating long-run marginal cost (LRMC) and LCOE are given in the appendix.

Existing production facilities available in the base scenario are depicted per area and technology in Figure 3.

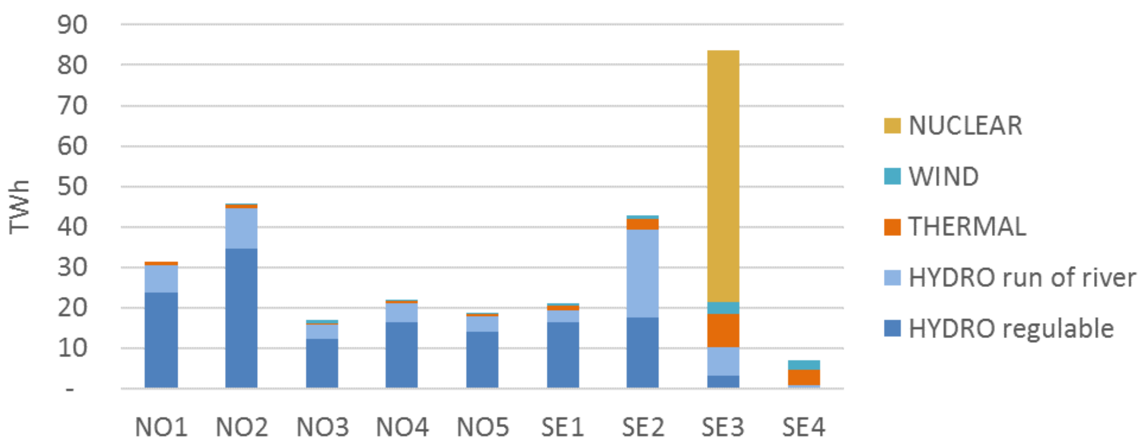

Figure 3 Existing technologies

Capacities of available technologies per area are presented in Table 3 in the appendix.

4.3 Characteristics of market demands in Norway and Sweden

The electricity consumption depends on many factors, for example temperature, business hours and electricity price. In our study we calculate regional electricity demand for a representative base year and a future year. We divide the year into timeslices in order to represent different temperature and activity levels.

We represent a price dependent demand in each price area of Norway and Sweden by a regional isoelastic demand function $Q_{rt} = Q_{0rt}\left(\frac{p_{rt}}{P_{0rt}}\right)^{\sigma}$, where we have calculated reference demand Q_{0rt} and reference price P_{0rt} as consumption and price averages from hourly observations 2012-2014 for each region and time-slice in the model. Figure 4 shows hourly observations of daytime electricity consumption and price in South Norway during 2014 for different seasons.

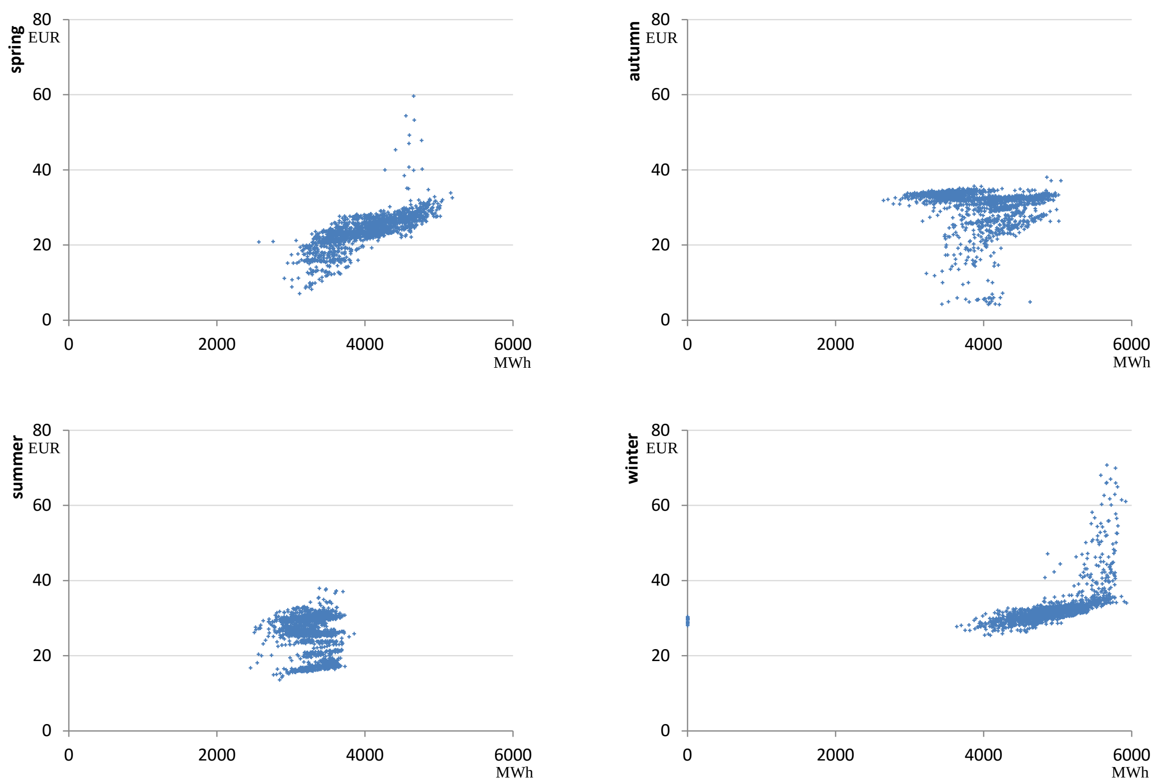

Figure 4: Electricity consumption in southern Norway (NO2), 2014, daytime. Source: NordPoolSpot

We notice that prices and consumption differs a lot during the year. 2014 prices were unusually low during spring, while consumption levels were the lowest during summer. Both prices and consumption were high during winter. We do not see a clear relationship between consumption and price in Figure 4. First, this is because other variables also affect the consumption. Much of the electricity is used for heating, and temperature is an important explanatory variable (Holstad and Pettersen 2011). Second, eelectricity spot prices are decided day-ahead based on prognosticated consumption and production, and few consumers are aware of the electricity price at the actual time of consumption. This suggests inelastic demand with a low (close to zero) own-price short-run elasticity. On the other hand, we know that price increases quickly raise media attention and public awareness, suggesting a relationship with a more negative long-run elasticity over weeks, months and years. Deployment of smart meters and improved demand side management may also change the consumer behavior in the future, resulting in more elastic demand (more negative own-price elasticities).

Empirical estimates of electricity own-price elasticity show inelastic short-run demand and more elastic long-run demand. Lijesen (2007) estimates a short-run elasticity of −0.029 based on hourly Dutch data, and reports long term estimates from other studies in the range from −0.1042 to −3.39 [6]. Azevedo, Morgan et al. (2011) uses annual data and estimate long-run own-price elasticities ranging from −0.2 to −0.25. Johnsen (1998) estimates the price elasticity in the Nord Pool power market to be between −0.5 and −0.35. Hjalmarsson (2000) estimates a long-term own-price elasticity in the Nord Pool power market of −0.039. Holstad and Pettersen (2011) estimates an elasticity of −0.05 based on monthly data from January 1996 to December 2010. They also report estimates based on rolling regressions in the range from 0 to −0.12 (see figure 4.2 on page 17). We have assumed an own-price demand elasticity of $\sigma = -0.1$ for all the Norwegian and Swedish price areas. The same value is used in Qi (1997) and Limpaitoon, Chen et al. (2014).

4.4 Timeslices

Electricity demand, production and power flows vary significantly over the day, week and year. We divide the year into separate intervals representing demand characteristics and operating modes of the transmission network. Based on observed hourly consumption and power flows through the transmission network, we define timeslices by calendar season and night versus day.

Figure 5 shows the average net flow of electricity into Norway and Sweden with these timeslices. We see that there is a seasonal pattern, and that the flow into Norway and Sweden have different levels at day versus night.

[6] See Table 1 on page 251.

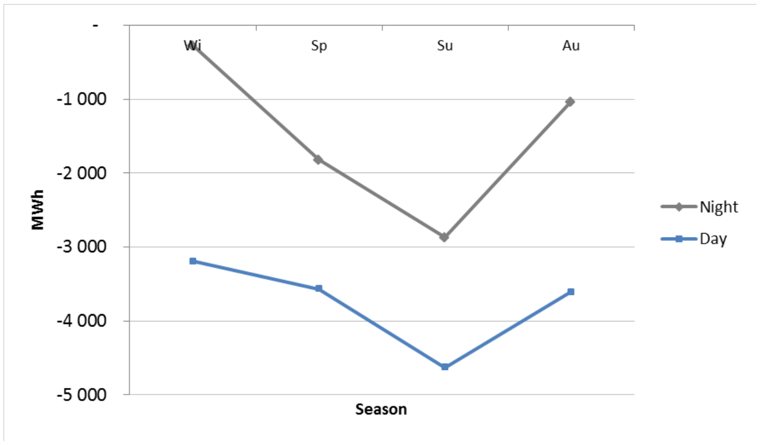

Figure 5 Average flow of electricity into Norway and Sweden by season and day/night. Source: NordPoolSpot

Figure 6 shows the average electricity prices per timeslice in East-Norway NO1 (which closely resembles NO2 and NO5) and Mid-Norway NO3 (which closely resembles NO4). We recognize the same seasonal pattern, and the price difference between day and night.

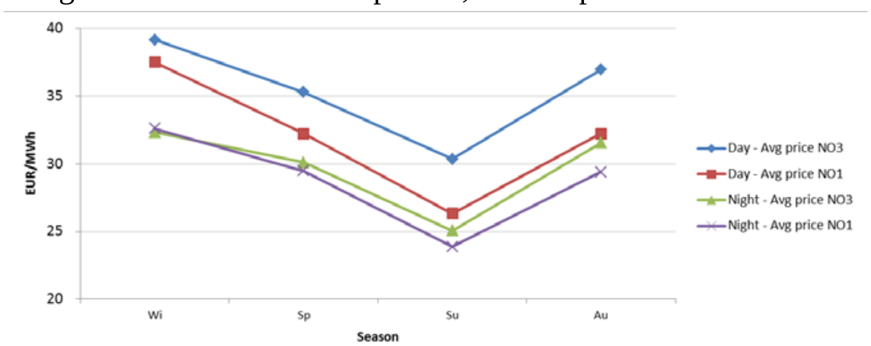

Figure 6 Average prices in NO1 and NO3 by season and day/night. Source: NordPoolSpot

Our model operates with reference prices P_{0rt} per area *r* and timeslice *t*. We use the observed timeslice averages as reference price and reference demand. Reference prices per area for each timeslice are shown in figure 17. Reference prices and quantities are given in table X in the appendix.

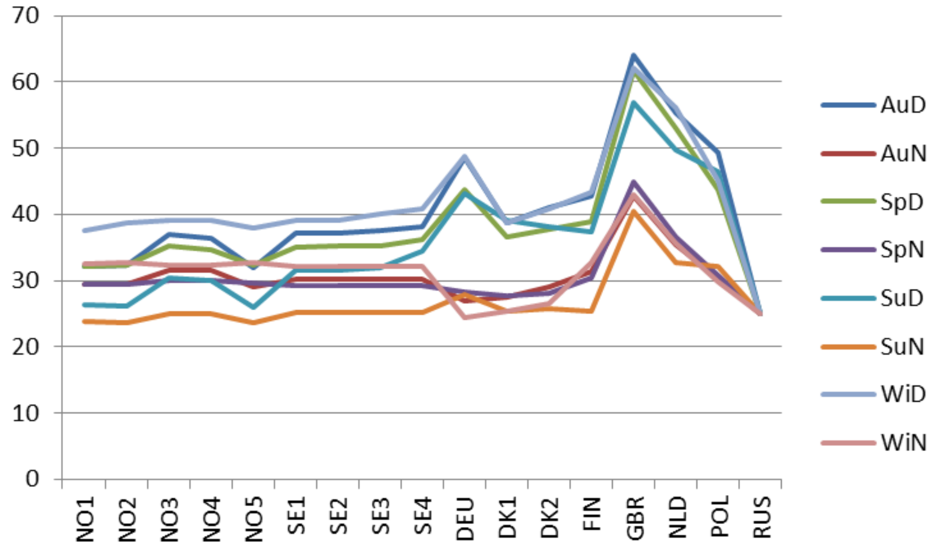

Figure 7 Reference prices per area and timeslice

4.5 External markets

We assume that cross-border cable capacities are sufficiently small to not affect market prices outside Norway and Sweden. All prices outside Norway and Sweden are kept constant at their reference price in all scenarios. Thus we assume that electricity can be exported within the cable capacity without reducing the price in the receiving area. We also assume that electricity is available for import at the external reference price within the cable capacity.

4.6 Transmission characteristics

Our model operates on an aggregated network. Capacities of the lines are net transfer capacities (NTC) collected from (ENTSO-E 2014). Line capacities of NO2-DK1, NO2-DEU and NO5-GBR are adjusted in different scenarios. We assume that most of our aggregated transmission lines have identical reactance, but we reduce reactance for SE1-SE2 and SE2-SE3 by 25% to obtain solvable and realistic flows in the network. The transmission values we have used are presented in Table 4 in the appendix.

4.7 Implementation

The model has been programmed in GAMS (Bussieck and Meeraus 2004), and the mixed complementarity problem has been solved with the PATH solver (Dirkse and Ferris 1995).

The model is solved successively in three steps. In the first step we solve a simplified optimization model without considering the green certificate scheme. Second we solve the complementarity model with linear demand. Ultimately we solve the complementarity model with isoelastic demand. This solve procedure was chosen in order to obtain initial starting points and help the solver to efficiently find a solution.

5 Results

The Nordic Green Certificate scheme will provide an increased amount of electricity production in Norway and Sweden, which will influence market prices by pushing prices downwards. Consumers must finance the certificates by a tax, but electricity price reductions may still increase the consumer surplus. The welfare effects of the green certificate scheme depend heavily on which future scenario that will manifest itself, but also on the geographical location of the individual actors.

In the base scenario electricity prices in Norway and Sweden are formed from internal thermal production, import from Finland during autumn night and summer day, and import from Denmark and Netherlands during summer night. Internal transport capacities between areas and production flexibility between time-slices make the area prices even out during most of the year.

Figure 8 shows average yearly electricity prices per area in different scenarios.

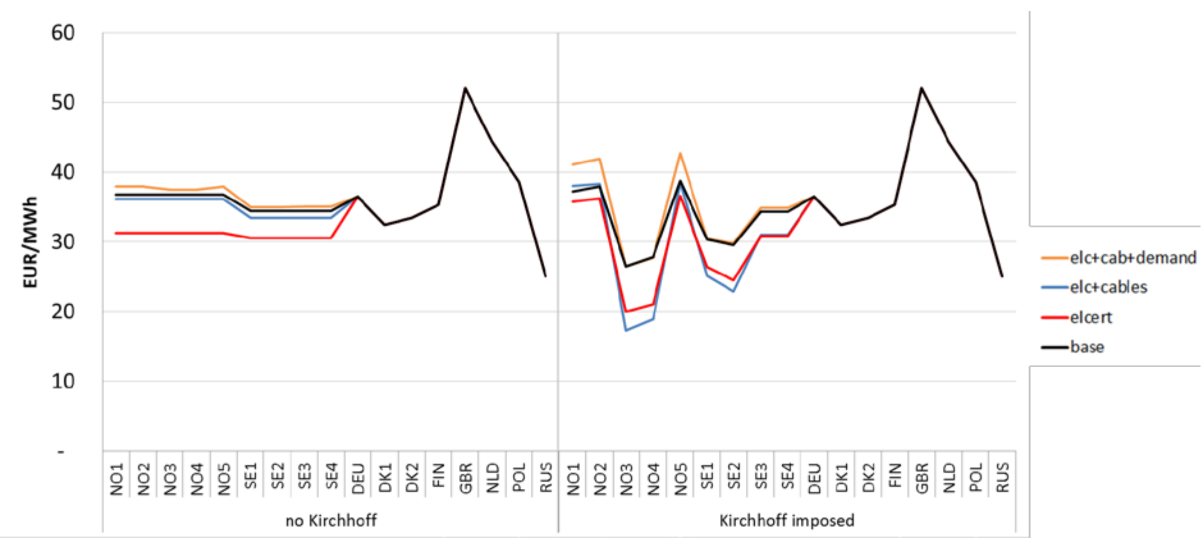

Figure 8 Average regional prices in different scenarios with and without Kirchhoff's Voltage Law imposed

When we impose Kirchhoff's voltage law, we get significant regional price differences. The northern price areas (NO4, NO3, SE1 and SE2) form considerably lower prices than the other areas in all scenarios. These areas have low consumption and net power export (with NO3 as an exception, but NO3 has sufficiently high inflow capacity from NO4 to inherit these properties). Less realizable grid capacity under Kirchhoff's voltage law leads to bottlenecks on connections towards the south, more lock-in of electricity in the north and thus lower prices.

Introducing the green certificate support scheme (*elcert* and *elcert_kvl*) leads to significant decrease in electricity prices compared to the *base* and *base_kvl* scenarios. Consumers benefit from this, while existing producers lose significantly. Old suppliers lose from 1.2 to 1.6 billion euros yearly, compared to the situation before the scheme (see Figure 9 below and Table 5 in the appendix). Consumers on the other hand increase their consumer surplus by 270 to 620 million euros each year, thanks to the decrease in electricity prices. The deadweight loss of the scheme is substantial in these scenarios: 36% of the support scheme cost is lost in total welfare reduction[7] when we do not consider Kirchhoff's voltage law. With Kirchhoff's voltage law imposed, the grid is less flexible and network capacities are harder to utilize. The geographical location in the grid becomes more important, and expensive projects with favorable grid locations improve their competitiveness. As a result, deadweight losses from the green certificate scheme increase to 43% of the support scheme cost when Kirchhoff's voltage law is imposed.

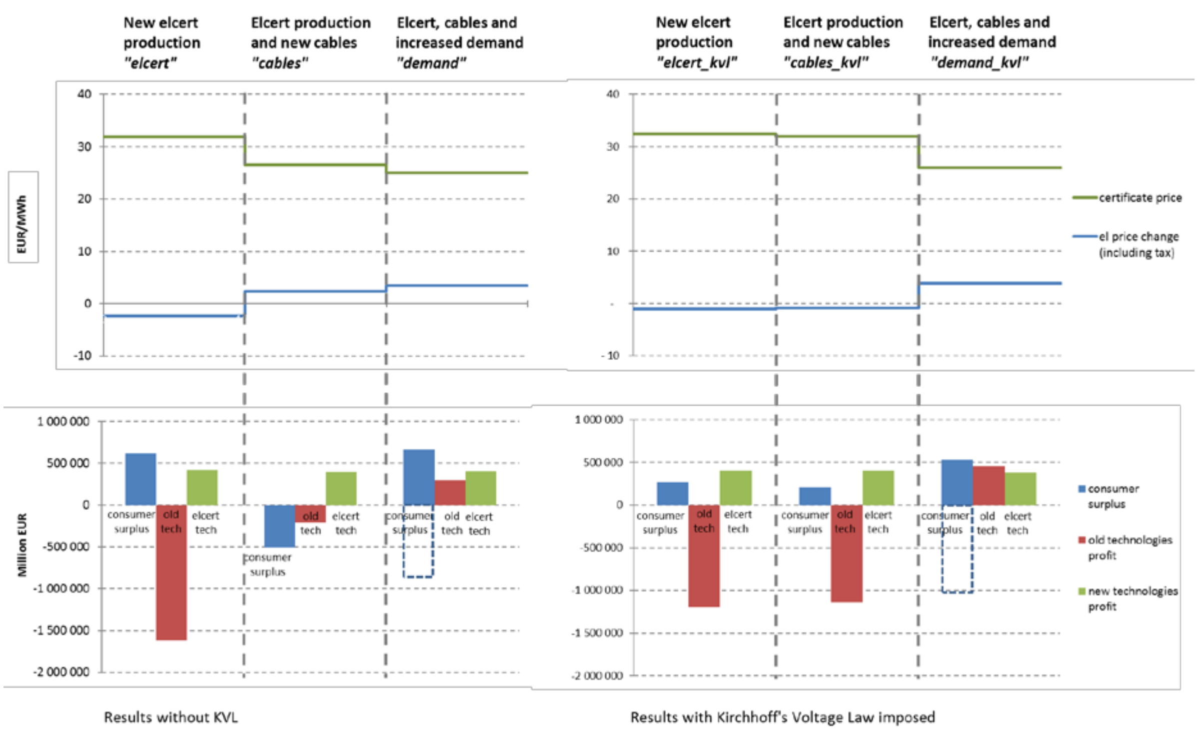

Figure 9 Certificate price, average electricity price change and welfare redistribution in different scenarios compared to base case

New producers (who receive green certificates) earn around 400 million euros yearly in the *elcert* scenario, and they earn about the same profit in each scenario. The different scenarios have much greater welfare distribution impacts for old suppliers, consumers and the TSO, than for new

[7] We address welfare reduction as calculated in the partial equilibrium model, not considering the unquantified welfare increase from the increased share of renewable electricity.

producers. The reason is that the electricity price and the green certificate price complement each other as shown in Figure 9, providing similar income for new producers in every scenario.

When new *cables* become available, the impact of Kirchhoff's voltage law on grid behaviour is evident at the aggregate level. When we do not consider Kirchhoff's voltage law, electricity prices increase from the *elcert* scenario, and the green certificate price decreases (see Figure 9). Existing producers still earn reduced profits compared to the base case (210 million euros less), but they benefit from the increased integration towards Northern Europe. Local consumers pay higher electricity prices (plus the certificate tax), and the consumer surplus decreases by 500 million euros yearly. New producers earning electricity certificates get similar profits as in the *elcert* scenario (400 million euros yearly), since changes in electricity and certificate prices are counteracting each other. Nonetheless there are different geographical outcomes between the two scenarios, since different production facilities are built due to network effects (see Figure 14).

When we include Kirchhoff's voltage law (scenario *cables_kvl*), we get similar welfare distribution effects as in the *elcert_kvl* scenario on the aggregated level shown in Figure 9. Electricity prices do not change much on average, but there are regional differences which we will return to. The grid is less flexible when Kirchhoff's voltage law is imposed. Higher prices abroad does not carry over to the southern regions in Norway and Sweden like in the *cables* scenario without KVL. In the *cables_kvl* scenario the TSO collects the welfare increase from new cables towards northern Europe (see Figure 11).

The TSO is a winner in both *cables* scenarios, increasing yearly profits by 400 to 490 million Euros (see Table 5). The positive effects from the new cables outweigh the deadweight loss from the green certificate scheme, so the combination of the scheme and cables is more efficient. We must however take into account the costs of new cables. These are not included in our model calculations[8].

Most of the production increase in these scenarios is exported from Norway and Sweden. When new cables become available, yearly net export increases *more* than production increases. Consumers in Norway and Sweden end up subsidizing new power production which gets exported to consumers in other countries. The increased local demand in the *demand* scenarios counteracts this effect. Export volumes are reduced significantly, but local electricity prices increase – particularly in the *demand_kvl* scenario. The certificate price decreases, and the certificate tax for consumers gets reduced. All four actors (consumers, old producers, new producers, TSO) are gaining in these scenarios. Thanks to higher prices, old producers are able to increase their profits by 300 to 460 million euros compared to the base scenarios. Consumers are also better off, thanks to the shift in the demand function. With the original demand function,

[8] Both the Nordlink and the North-Sea Network cables are expected to cost 1.5-2 billion Euro, and the Norwegian TSO owns 50% of both. The TSO increases yearly profits by 0.34 billion Euro, which means that the investment is recovered after 5-7 years assuming a 5% discount rate.

consumer surplus would instead have decreased by 870 to 1010 million euros, which is more than the certificate value of the scheme (this is indicated in Figure 9 by the dashed “ghost” bars).

The net social welfare redistribution effects for each geographical area is shown in Figure 10 (we do not consider TSO profit here). Only two regions have positive net social welfare change in the *elcert* and *cables* scenarios, all the other areas carry a loss. The NO5 area has a positive net social welfare change in all scenarios. The reason is that NO5 gets green certificates from highly profitable new hydro generation. The SE3 area has the highest consumption and production, and thus the largest variation between scenarios. SE3 has substantial losses in the *elcert* and *cables* scenarios, but the biggest welfare gain in the *demand* scenarios. We see that there are wide ranges of outcomes for several regions, for example NO2 and SE2 which may experience considerable decreases of net social welfare.

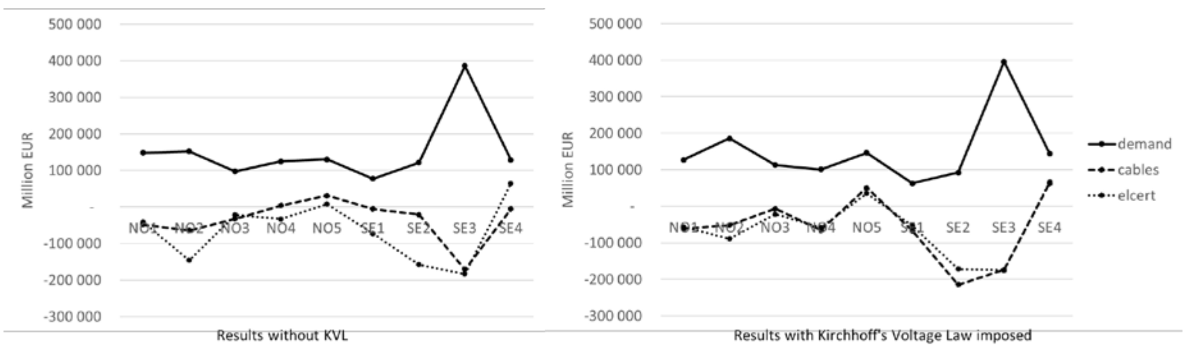

Figure 10 Regional net social welfare change

The regional welfare effects on this aggregation level are quite similar, regardless of whether Kirchhoff's voltage law is imposed or not. The distribution of welfare between market players is however strongly dependent of the grid flexibility. If we do not consider Kirchhoff’s voltage law, the distribution between players is homogenous across regions in all scenarios. Changes in old producer profits and consumer surplus have the same sign in each region for each scenario. We refer to Figure 23 to Figure 25 in the appendix for separate welfare components and TSO profits.

Imposing Kirchhoff’s voltage law creates disparities between players in different regions. Electricity prices in east, south and west Norway (NO1, NO2 and NO5) do not decrease as much in the *elcert_kvl* scenario, and increase more in the *demand_kvl* scenario. Due to these price movements, consumers in NO1, NO2 and NO5 consistently lose consumer surplus in all kvl-scenarios. This effect is apparent in Figure 11, which shows welfare change for each actor in the *cables-kvl* scenario. Electricity prices decrease in all other areas, and consumers gain while existing producers lose. Old producers in SE3 are crowded out, and reduce their generation by 4 TWh. The TSO profit increases significantly, thanks to increased power transfer volumes in an inflexible grid.

Figure 11 Geographical welfare distribution effects going from *base* case to elcert scheme with new *cables* towards Europe with Kirchhoff's voltage law imposed (cables_kvl scenario)

NO5 and SE4 are the only regions that experience a net positive welfare change. Consumers in NO5 lose surplus and old producers gain, while the outcome in SE4 is opposite. Figure 26 and Figure 27 show similar regional disparities in scenarios *elcert_kvl* and *demand_kvl*.

5.1 Certificate prices and new generation investments

Our results indicate that certificate prices need to be in the same range as electricity prices in order to facilitate new renewable production to fulfil the goal of the support scheme, see Figure 12.

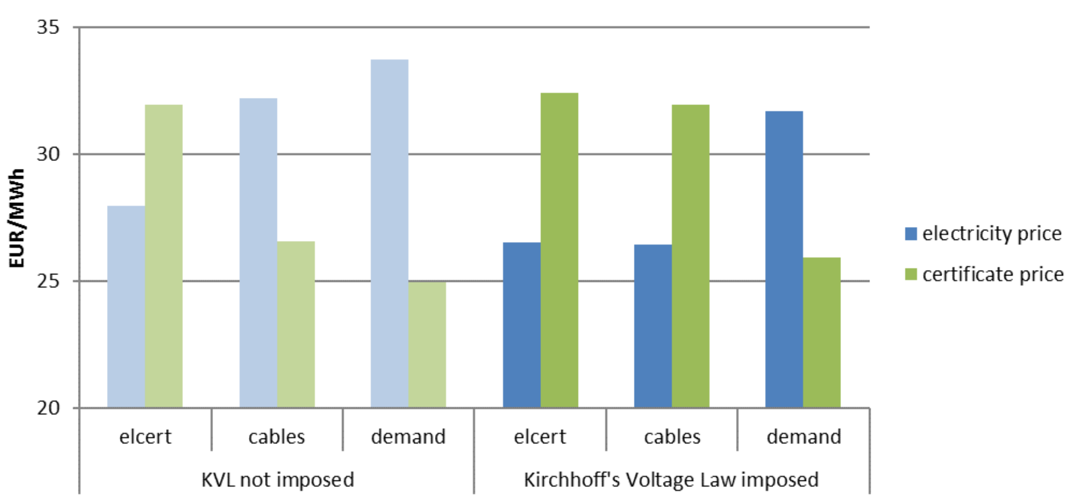

Figure 12 Certificate and electricity prices by scenario

Each scenario has a positive certificate price, and thus reaches the production goal of the support scheme exactly. Figure 13 shows the amount of each generation technology by scenario. The different technologies are sorted by increasing LCOE (except onshore wind in Norway which consists of a group of different projects with individual LCOE costs). The most expensive renewable technology is defining the certificate price in each scenario.

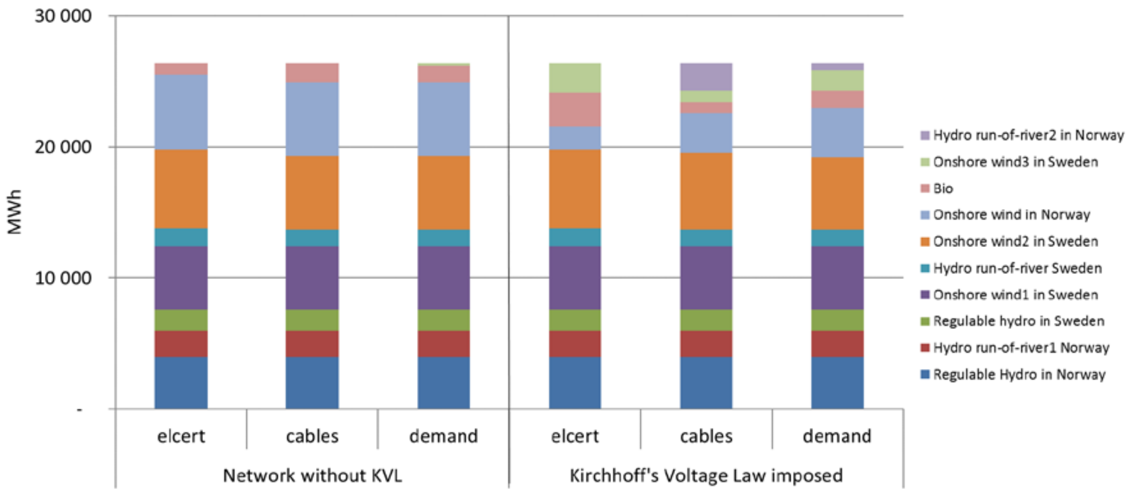

Figure 13 Production technologies by scenario

As a starting point a project's LCOE determines whether that project will be developed (assuming adequate local demand or network capacity). When new cables and increased local demand are introduced, the geographical location of each project becomes increasingly important. More expensive technologies are developed when Kirchhoff's voltage law is imposed, and the different scenario assumptions affect the usage of technologies more. The reason is that transmission network capacities becomes less flexible, and the project location matters more.

Figure 14 shows the variation in renewable electricity expansion between the different scenarios. New cables make electricity prices increase, and bio projects in SE3 and SE4 become profitable. When local demand also increases, more expensive wind projects in SE4 are developed (wind 3 in Figure 14).

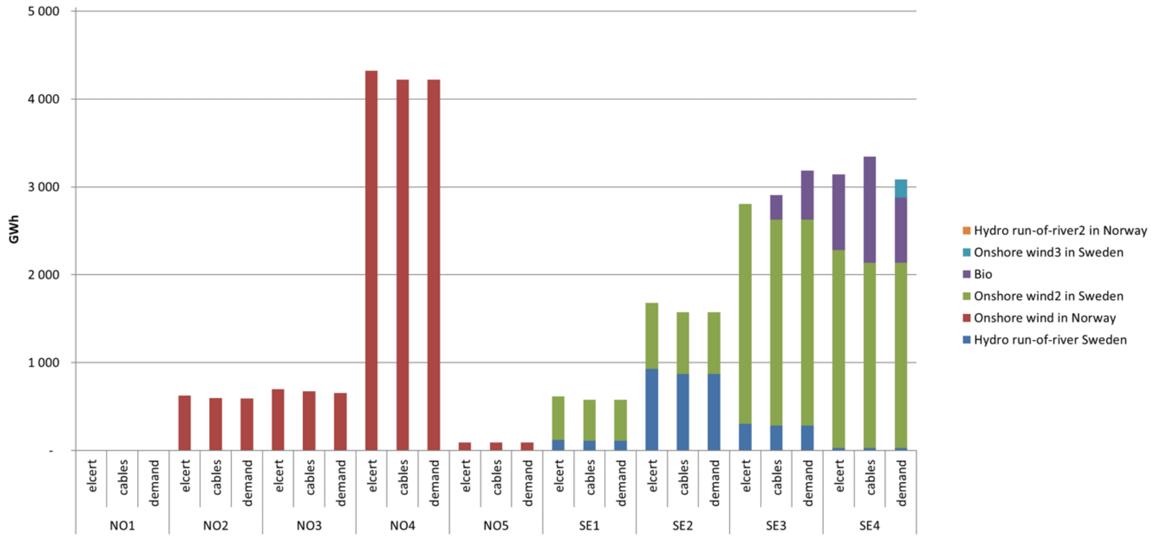

Figure 14 Green certificate generation by region and technology, Kirchhoff's voltage law not imposed

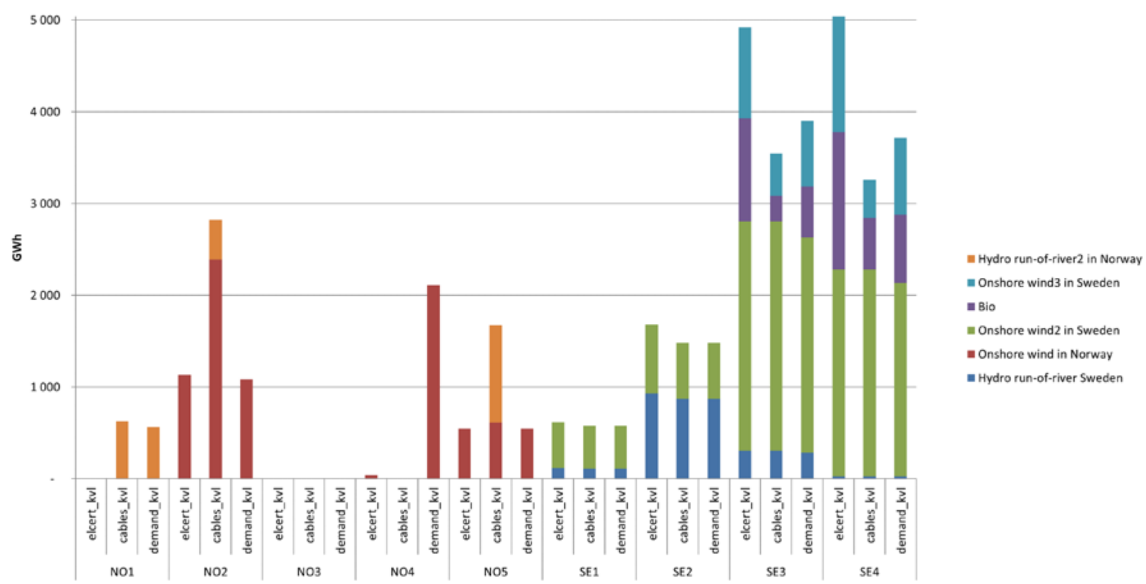

Figure 15 Green certificate generation by region and technology with Kirchhoff's voltage law imposed

When Kirchhoff's voltage law is imposed (Figure 15), fewer Norwegian projects are developed. The transmission network is not capable of transmitting wind power from the NO3 and NO4 regions in northern Norway. Instead more new generation projects in southern parts of Sweden are developed. In the *demand_kvl* scenario, some wind projects in NO4 become profitable.

The *cables_kvl* scenario triggers more expensive hydro run-of-river projects in the southern parts of Norway, closer to the North-European markets. There is a tradeoff between favorable location versus intrinsic project profitability. New cables in the AC-network enables investments in more expensive technologies closer to the European markets. Increased local demand dampens these effects.

When we impose Kirchhoff's voltage law on the AC-network, more expensive projects are built. This increase the deadweight losses for society. The TSO can make grid investments to remove bottlenecks in the grid. As we see, a more flexible grid enables improved utilization of natural resources, but comes at a cost of capital[9].

Figure 15 seems to indicate that cheaper generation is reduced at the same time as more expensive generation increases (see for example the cables scenario in SE4 where generation from bio is reduced but more expensive wind3 projects are still producing). The reason is the seasonal production within the year. Bio generation is fully exploited in every timeslice the wind production is used (see Figure 28 in the appendix for details).

We conclude this section by showing observed market prices of electricity and green certificates[10]. Figure 16 shows observed prices since before the common green certificate market was opened (green certificate prices in 2011 are from the national Swedish market that existed before the common market was established).

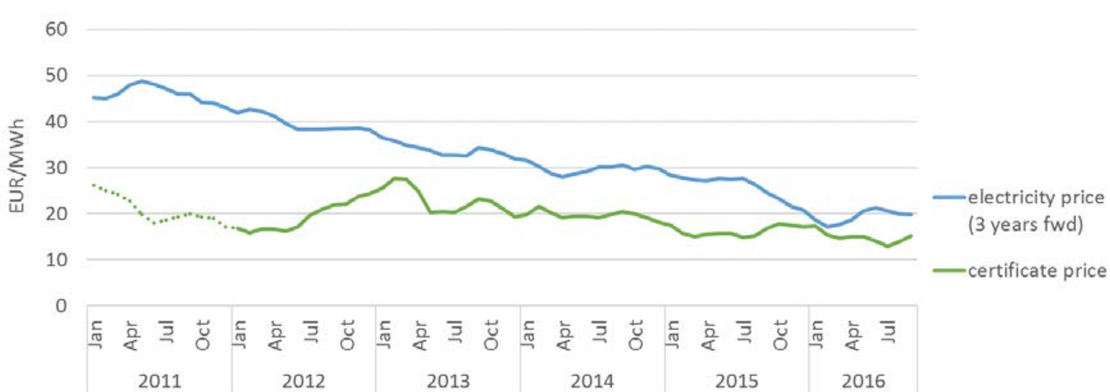

Figure 16 Observed prices of electricity (3 years forward) and green certificates

The results from our *elcert* scenarios do not seem unreasonable, based on these observations. Electricity prices have fallen considerably, and green certificate prices are of the same magnitude as electricity prices. New cables towards Northern Europe are still some years ahead, and are expected to raise electricity prices (as our *cables* scenario indicate).

[9] Further grid expansions may also have additional environmental impacts, which we do not consider here.
[10] We show 3 years forward prices of electricity because these are less volatile than spot prices, making it easier to see the trend in the figure. Data sources are Thompson Reuters Datastream and SKM Svensk Kraftmäkling at http://www.skm.se/priceinfo/history.

6 Conclusions

We have implemented a partial equilibrium complementarity model and calculated the theoretic value of green certificates from generalized Nash equilibria in a representative production year assuming perfect competition and perfect market information.

To force a 10 per cent increase in electricity production by increased renewable generation in Norway and Sweden requires a green certificate price in the same range as the price of electricity.

It is costly for society to subsidize more expensive renewable generation if there is no corresponding demand that can utilize the increase. The yearly cost for society of the support scheme without any new demand is in the range of 300 million Euro, meaning that 35-40 per cent of the full scheme certificate value would disappear in deadweight losses. This burden is shared between consumers and existing producers. New cables towards Europe are important for the efficiency of the support scheme. Transmission investments provides market integration which diminish deadweight losses. A local demand increase makes the electricity more valuable and has a similar effect.

The introduction of the green certificate scheme ceteris paribus leads to losses for existing producers due to considerable electricity price declines. Consumers gain when the price declines, while new renewable producers are assured the necessary profits from the green certificates. New cables towards Europe affect the burden sharing between producers and consumers. Improved cross-country exchange is advantageous for existing producers, unless bottlenecks in the grid allows the TSO to profit from the price differences. A concomitant demand increase would create the best outcome, increasing net social welfare and prevent export of subsidized power. The TSO gains from increased production in all scenarios. New cables create higher revenues (which may finance the investment), while local increase in demand dampens the TSO profits.

Furthermore, we conclude that the supranational green certificate support scheme may have considerable local welfare transfer effects. The regional market outcomes depend crucially on the transmission grid. Electricity production must be connected to the grid, and our results indicate that the geographical location of the project is relevant.

Grid investments that remove bottlenecks can make decentralized projects with favorable costs feasible. This would decrease green certificate prices and reduce deadweight losses. The societal benefit from improved utilization of natural resources must be weighed against the societal cost of making the grid investments.

In order to capture these effects, Kirchhoff’s voltage law should not be overlooked. It makes the project location in the grid matter more, and affects which projects that are built. Projects with favorable locations but more expensive production technologies are chosen, and they demand higher certificate prices. This results in higher deadweight losses.

On the surface a green certificate policy scheme seems very flexible and easy to implement, and politicians can leave it to the market to decide the best implementation of the policy goal. In reality grid expansions are often necessary for new production and decisive for profitability. The TSO may strongly affect where new production will be profitable. This creates difficult planning and decision problems for the electricity generators. Infrastructure investments in the grid affect which projects are built, and as a consequence also the regional welfare effects from the tradable green certificate scheme. The net social welfare effects depend on the TSO's ability to optimize its grid investments.

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9 Appendix

9.1 The mathematical model

For definition of sets, parameters and variables, see section 3.

Producer problem (perfect competition)

The producer chooses his generation and sales in order to maximize profit. He acts as a price taker, and assumes that his production will not influence the market price (perfect competition). Producer *f* solves the following problem:

$$\underset{s_{frt},x_{ift}}{Max} \qquad \sum_{r\in R}\sum_{t\in T}\Big[(p_{rt}-w_{rt})s_{frt}-\sum_{i\in I}(c_i-w_{rt})x_{ift}+\sum_{i\in I_c}\mu\, x_{ift}\Big]$$

Each producer maximizes his profit, which is comprised by three components: income, production cost and certificate income. The wheeling cost w_r is paid to the TSO for transporting power s_{frt} to region *r* from the transmission network. When the producer generates power x_{ift} in its own region, the TSO pays the regional wheeling fee to the producer for receiving power into the network. The producer also receives the certificate price μ for each MWh of renewable electricity x_{ift} generated using a technology eligible for certificates $i \in I_c$.

$$Supply: \qquad \sum_{r\in R} s_{frt} - \sum_{i\in I} x_{ift} \le 0 \qquad ,f \in F, t \in T \qquad (\omega_{ft})$$

The supply constraint inhibits the producer from selling more power s_{frt} than he produces x_{ift} in each timeslice. It is possible to produce more power than supplied. This would imply that the marginal income ω_{ft} is zero.

$$Flexlim: \qquad x_{ift} \le G_{if}\frac{h_t}{H}f_i \qquad ,i \in I, f \in F, r \in R \qquad (\varphi_{ift})$$

The Flexlim constraint represents flexible production limits. We assume that each production technology has an upper capacity bound G_{if} in the analysis period. If the flexibility parameter f_i is greater than one, then technology i has timing flexibility to move production between timeslices - else production capacity is assumed to be constant, thus the production limit is proportional to the length of the timeslice. The flexible production limit has a shadow price of φ_{ift}.

$$Prodlim: \qquad \sum_{t} x_{ift} \le G_{if} \qquad ,i \in I, f \in F \qquad (\psi_{if})$$

The Prodlim constraint represents the total production limits. If technology i has timing flexibility, it still must produce within the capacity bound G_{if} in the analysis period. The production limit has a shadow price of ψ_{if}.

At last we add nonnegativity constraints on the decision variables for supply and generation.

$$s_{frt} \geq 0, x_{ift} \geq 0$$

The Karush-Kuhn-Tucker (KKT) conditions are found by formulating the Lagrangian function and taking partial derivatives with respect to the independent variables and to the Lagrange-multipliers (dual variables).

Grid owner / TSO problem (Nash-Bertrand assumption)

We assume that the grid owner naively acts as a price taker, and chooses grid flows to maximize her profit while adhering to Kirchhoff's current and voltage laws and transmission capacities. Since we assume perfect competition, arbitrage opportunities will not occur, and we do not consider arbitrage in this model.

$$\underset{z_{rkt}}{Max} \quad \sum_{r\in R}\sum_{t\in T}\left[w_{rt}\left(\sum_{f\in F} s_{frt} - \sum_{i\in I, f\in F_r} x_{ift}\right)\right]$$

The grid owner maximizes his income from the wheeling fee on power flowing to each region.

$$KCL: \quad \sum_{f\in F} s_{frt} - \sum_{f\in F_r}\sum_{i\in I} x_{ift} - \sum_{k\in R} z_{krt} + \sum_{k\in R} z_{rkt} = 0 \qquad , r\in R, t\in T \qquad (w_{rt})$$

The KCL constraint states Kirchhoff's current law: The sum of currents flowing into a node or region is equal to the sum of currents flowing out of that node, so the sum of all currents meeting in region *r* must be zero. The shadow price w_{rt}equals the cost of transporting electricity from the grid to region *r* in timeslice *t*.

$$KVL: \quad \sum_{(r,k)\in K_v} R_{rk}(z_{krt} - z_{rkt}) = 0 \qquad , v\in N, t\in T \qquad (\kappa_{vt})$$

Kirchhoff's voltage law (also called Kirchhoff's loop rule) is represented by the KVL constraint. The law says that the directed sum of the electrical potential differences (voltages) around any closed cycle in the network is zero. A potential difference over the cycle would create a current, and we cannot have a positive flow running through any cycle in the network. The sum of flows adjusted by the reactance R_{rk} of the line between region *r* and region *k* must be zero.

$$Flowlim: \quad z_{rkt} \leq L_{rk}h_t \qquad , (r,k)\in K, t\in T \qquad (\tau_{rkt})$$

The flowlim constraint represents the capacity of the lines. This capacity depends on temperature, security limits and other parameters, but we assume a directed net transfer capacity L_{rk} for each line. We assumed the line capacity to be constant, thus the flow limit is proportional to the length of the timeslice.

We also need nonnegativity constraints on the directed flow variables.

$$z_{rkt} \geq 0$$

Consumer / Market clearing

The representative consumer acts as a price taker. We assume an iso-elastic demand curve. Demand in a region *r* during timeslice *t* is $Q_{rt} = Q_{0rt}\left(\frac{(p_{rt}+t_{\mu})}{P_{0rt}}\right)^{-\sigma}$, where σ is the absolute value of the own-price demand elasticity. Her willingness to pay for a quantity q_{rt} is $W_{rt}(q_{rt}) = P_{0rt}\left(\frac{q_{rt}}{Q_{0rt}}\right)^{-\frac{1}{\sigma}}$, where $q_{rt} = \sum_f s_{frt}$. The consumer wants to maximize her consumer surplus:

$$\underset{Q_{rt}^*}{Max} \sum_{t\in T}\left[\int_0^{Q_{rt}^*}\left(W_{rt}(q_{rt}) - p_{rt} - t_{\mu}\right) dq_{rt}\right] \quad \text{where} \quad W_{rt}(q_{rt}) = P_{0rt}\left(\frac{q_{rt}}{Q_{0rt}}\right)^{-\frac{1}{\sigma}}$$

The KKT conditions give us the Market Clearing Conditions

$$P_{0rt}\left(\frac{\sum_{f\in F} s_{frt}}{Q_{0rt}}\right)^{-\frac{1}{\sigma}} - p_{rt} - t_{\mu} = 0 \qquad , r \in R, t \in T \quad (\, p_{rt} \text{ free})$$

Tax agent

The tax agent minimizes the tax needed to finance the green certificates that are necessary to fulfill the renewable quota obligation.

$$\underset{t_{\mu}}{\text{Min}}\, t_{\mu}$$

The tax rate should be as low as possible, in order to minimize the socioeconomic deadweight loss the tax will incur. The tax on electricity must cover the value of the certificates.

$$Tax: \qquad \sum_{t\in T}\sum_{r\in R}\sum_{f\in F} s_{frt}\, t_{\mu} \geq \sum_{t\in T}\sum_{f\in F}\sum_{i\in I_c} x_{ift}\mu \qquad (\lambda_1)$$

The tax rate is nonnegative.

$$t_{\mu} \geq 0 \qquad (\lambda_2)$$

Certificate/quota constraint

Regulating authorities decide a volume *V* of new renewable electricity production.

$$Elcert: \qquad \sum_{i\in I_c}\sum_{f\in F}\sum_{t\in T} x_{ift} \geq V \qquad \perp (\mu \geq 0)$$

The dual price μ of this constraint becomes the value of certificates. This is the lowest certificate value needed to achieve the target of renewable production. Producers could choose to generate more than the target, in which case the certificate value will become zero.

9.2 Formulas for LRMC and LCOE

The Long-Run Marginal Cost (LRMC) in Table 2 is calculated as

$$LRMC_i = I_i \frac{r}{(1-(1+r)^{-T_i})} + \frac{F_i}{365 \cdot 24 \cdot a_i} + SRMC_i \tag{13}$$

The Levelized Cost of Electricity (LCOE) is calculated as

$$LCOE_i = SRMC_i + (LRMC_i - SRMC_i) \frac{(1-(1+r)^{-T_i})}{(1-(1+r)^{-E})} \tag{14}$$

where E is the lifetime of green certificates, which is 15 years in the Swedish-Norwegian support scheme.

9.3 Demand drivers, market factors and timeslices

Consumption and production in Norway and Sweden may differ substantially from year to year, depending on temperature and the hydrological balance. 2012 was cold, while 2013 was a dry year with precipitation below normal for Scandinavia. This resulted in higher electricity prices, see Figure 17. 2014 was a warm year, with lower electricity prices.

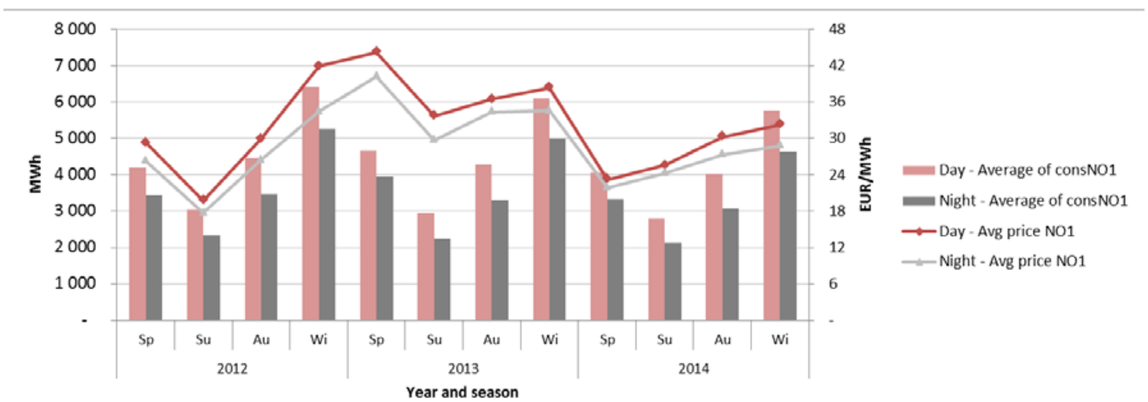

Figure 17 Average electricity price and consumption in East Norway (NO1) by year and season. Source: NordPoolSpot

These effects make market prices and demand appear positively correlated. Consumption is higher during winter hours than in summer hours, and there is a tendency that prices are higher when consumption is high (the correlation coefficient between price and volume is 0,45). We define timeslices to include this seasonal variation.

Figure 18 shows average hourly consumption volumes and prices for each price area in Norway and Sweden based on hourly observations from 2012-2014. We notice that consumption seems relatively independent of the price, indicating inelastic demand.

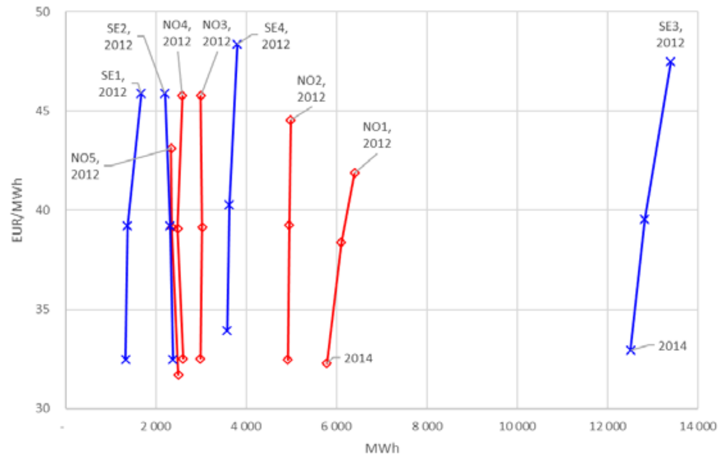

Figure 18: Electricity consumption and price, winter day averages, 2012-2014. Source: NordPoolSpot

Both prices and consumption volumes are highest in 2012 and lowest in 2014. Outdoor temperature is an important demand driver, since electricity is commonly used for space and water heating. Figure 19 shows heating degree days (with base 17 degrees Celsius), indicating that 2012 was a cold year and 2014 a warm year.

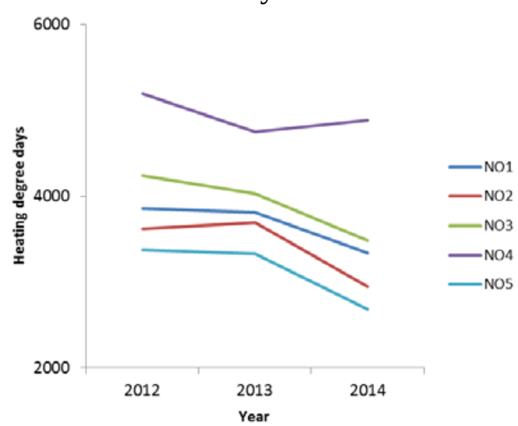

Figure 19 Heating degree days. Source: Norwegian Meteorological Institute

9.3.1 Day versus night

European electricity prices are low during night. Since Norway and Sweden have flexible production due to high shares of controllable hydro power, it is profitable to import during night and export during day. All the cross-border connections show a similar pattern over the day, except the relatively small northern connectors from Norway towards Russia and Finland.

Figure 20 shows average net flow into Norway and Sweden by season and hour of the day.

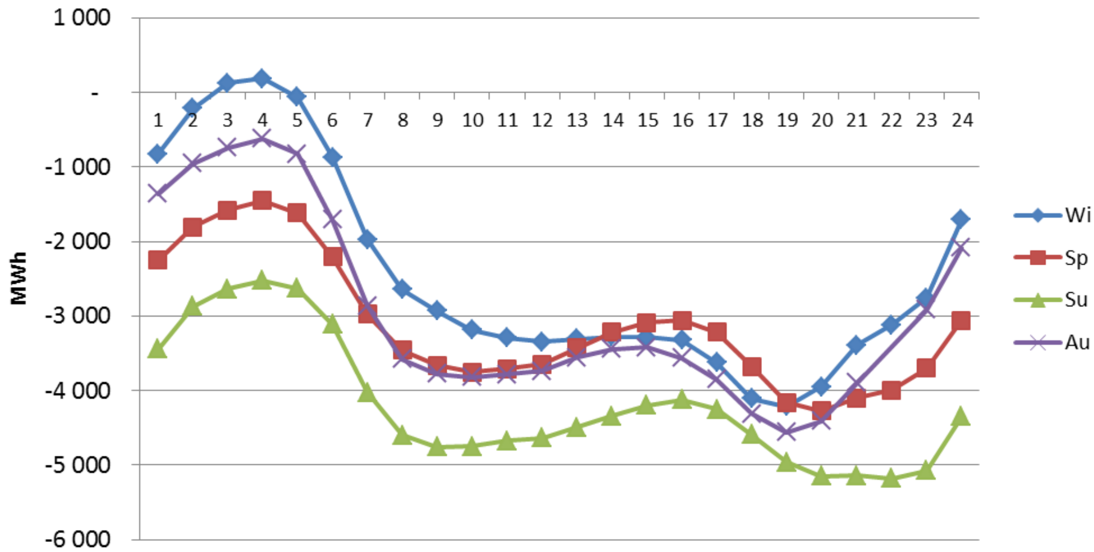

Figure 20 Average net power flow into Norway and Sweden by season and hour of day, 2012-2014. Source: NordPoolSpot

Flows during hours 23-24 and 06-07 are similar to afternoon hours during spring and summer, while flows during hours 00-06 are significantly higher than the rest of the day. Based on Figure 20, we define night-time as the six hours from 00-06, and daytime as the 18 hours from 07-24.

9.3.2 Seasonal variation

Figure 21 shows the flow pattern of electricity into Norway and Sweden by sequential day of the year. We notice that the average net flow goes out from Norway and Sweden during the year, as both countries are net exporters. During 2012-2014 there have been large export days during the whole year, while there are summer days without net import during this period. There are apparent changes during the year, as the calendar seasons have different characteristics (see also Figure 4). Norway and Sweden have relatively big temperature differences between summer and winter, which affects electricity consumption significantly as electricity is used for heating especially in Norwegian residents. The spring is characterized by much run-of-river hydro production, compared to the autumn.

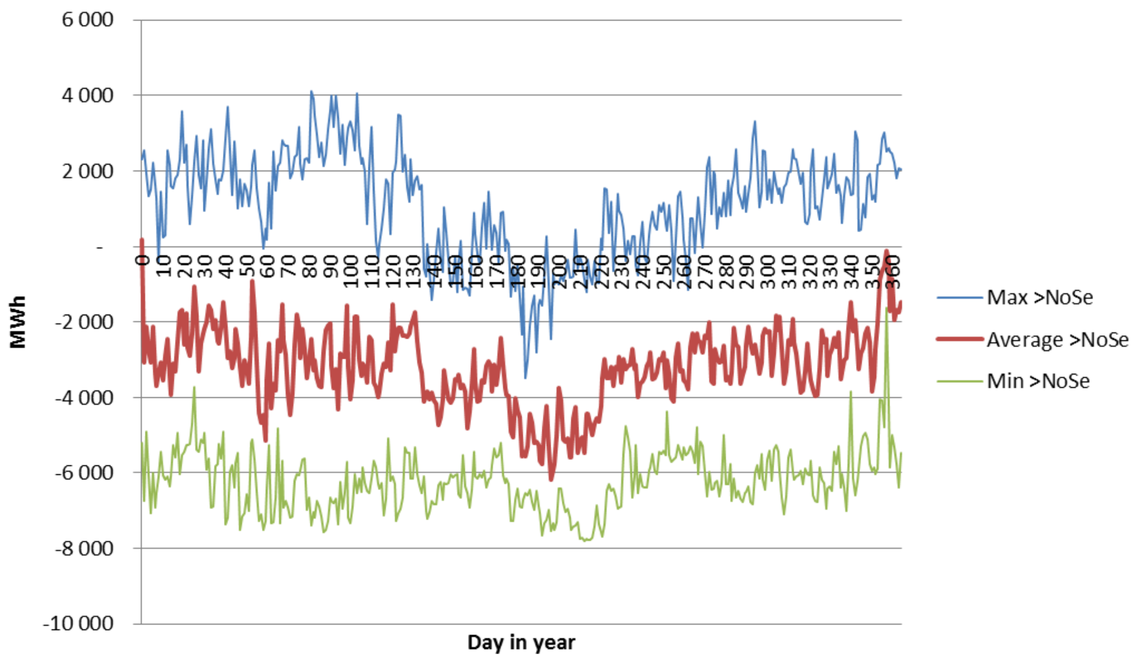

Figure 21 Electricity flow into Norway and Sweden by day, 2012-2014. Source: NordPoolSpot

We could try to improve the timeslice definitions by finding date limits that provides maximum discrimination between seasons, but it is hard to find such dates based on Figure 21. Separate area connections may have date candidates which divide seasons more clearly, but these dates shift from connection to connection. For the total system we conclude that calendar seasons winter, spring, summer and autumn explain a significant share of the yearly variation.

9.3.3 Weekday variation

The consumption, production and flow of electricity change during the week. Most shops are closed on Sundays, and many business sectors have low activity during weekends. The electricity demand decreases as a result. Flexible hydro power producers can store water for later production, while inflexible and intermittent supply technologies remain producing electricity and earn lower power prices. (Some technologies may earn subsidies like green certificates or feed-in-tariffs in addition to the market price of electricity, and wish to produce with very low or even negative market prices.)

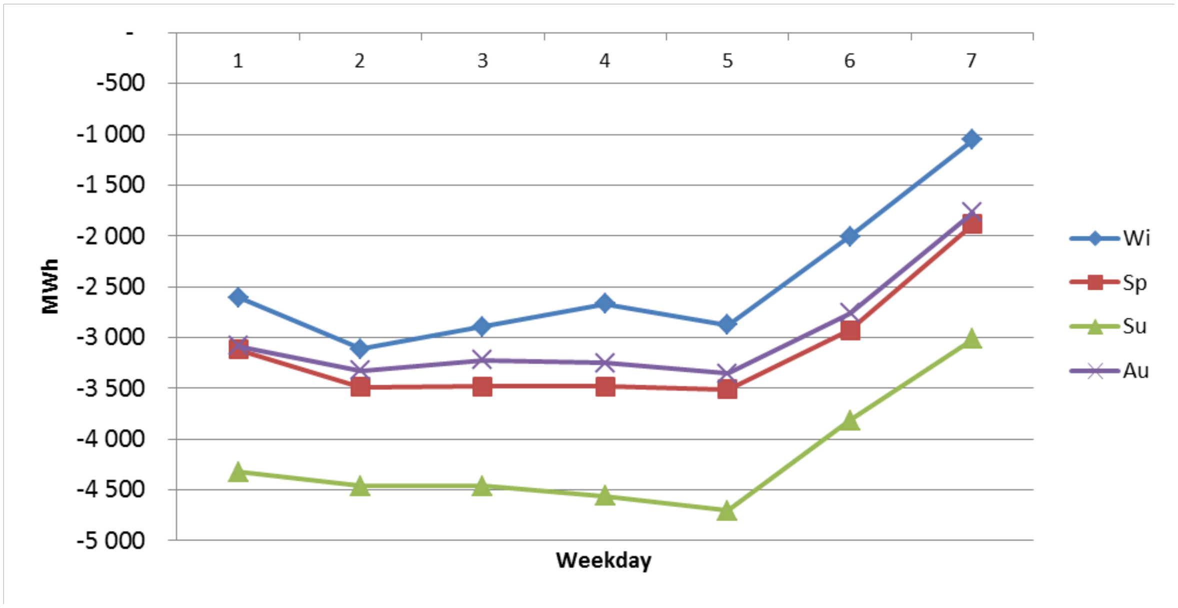

Figure 22 Average flow of electricity into Norway and Sweden by weekday and season, 2012-2014. Source: NordPoolSpot

Figure 22 shows that there is a weekend effect on power flow into Norway and Sweden. In this study we ignore this effect.

9.4 Technology capacities

Capacities of available technologies per area are presented in Table 3.

Table 3 Capacities of available technologies per area

		NO1 [GWh/year]	NO2 [GWh/year]	NO3 [GWh/year]	NO4 [GWh/year]	NO5 [GWh/year]	SE1 [GWh/year]	SE2 [GWh/year]	SE3 [GWh/year]	SE4 [GWh/year]
Existing	HYDREG0	23 854	34 657	12 360	16 435	13 954	16 574	17 602	3 257	252
	HYDROR0	6 772	9 840	3 509	4 666	3 962	2 765	21 721	7 128	702
	THERMAL0	783	1 138	406	540	458	1 170	2 566	8 222	3 608
	WIND0	-	288	808	400	73	594	988	2 851	2 531
	NUCLEAR0	-	-	-	-	-	-	-	62 239	-
Fossil	NG01	300	300	300	300	300	300	300	300	300
	NGCC	300	300	300	300	300	300	300	300	300
	NG02CO2	300	300	300	300	300	300	300	300	300
	NGPEAK_101	300	300	300	300	300	300	300	300	300
New hydro	HYDRUN04	446	306	205	287	755	-	-	-	-
	HYDRUN05	669	460	308	431	1 133	-	-	-	-
	HYDREG07	892	613	410	575	1 510	-	-	-	-
	HYDREG_101	-	-	-	-	-	710	754	140	11
	HYDRUN_101	-	-	-	-	-	118	931	305	30
	BIO	-	-	-	-	-	500	1 000	1 500	2 000
wind	WIND_on1SE	-	-	-	-	-	200	300	1 000	900
	WIND_on2SE	-	-	-	-	-	400	600	2 000	1 800
	WIND_on3SE	-	-	-	-	-	800	1 200	4 000	3 600
	WIND_offSE	-	-	-	-	-	800	1 200	4 000	3 600
	WIND_offNO	-	300	300	300	300	-	-	-	-
wind projects	W1A107N2	-	34	-	-	-	-	-	-	-
	W2A128N3	-	-	165	-	-	-	-	-	-
	W3A112N4	-	-	-	368	-	-	-	-	-
	W4A111N5	-	-	-	-	25	-	-	-	-
	W5A108N2	-	23	-	-	-	-	-	-	-
	...	...	...	...	...	...	...	...	...	...

9.5 Transmission network

Transmission values for the transmission network are presented in Table 4. Six transmission line capacities were adjusted between the relevant scenarios.

Table 4 Network capacities based on ENTSO-E maximum net transfer capacities

From	To	Capacity	Reactance
NO2	DK1	1000 / 1632	2
DK1	NO2	1000 / 1632	2
NO2	DEU	0 / 1400	2
DEU	NO2	0 / 1400	2
NO2	GBR	0 / 1400	2
GBR	NO2	0 / 1400	2
NO1	NO2	2200	2
NO1	NO3	500	2
NO1	NO5	300	2
NO1	SE3	2145	2
NO2	NO1	3500	2
NO2	NO5	500	2
NO3	NO1	500	2
NO3	NO4	200	2
NO3	SE2	600	2
NO4	NO3	1000	2
NO4	SE1	700	2
NO4	SE2	250	2
NO5	NO1	3700	2
NO5	NO2	600	2
SE1	NO4	600	2
SE1	SE2	3300	1.5
SE2	NO3	1000	2
SE2	NO4	300	2
SE2	SE1	3300	2
SE2	SE3	7300	1.5
SE3	NO1	2095	2
SE3	SE2	7300	2
SE3	SE4	5300	2
SE4	SE3	2000	2
NO2	NLD	700	2
NO4	FIN	70	2
SE1	FIN	1500	2
SE3	DK1	680	2
SE3	FIN	1200	2
SE4	DEU	615	2
SE4	DK2	1300	2
SE4	POL	600	2
DEU	SE4	615	2
NLD	NO2	700	2
DK1	SE3	740	2
DK2	SE4	1700	2
POL	SE4	600	2

RUS	NO4	56	2
FIN	NO4	70	2
FIN	SE1	1100	2
FIN	SE3	1200	2

9.6 Results

Table 5 shows numerical results from all scenarios.

Table 5 Numerical results from all scenarios

Scenario	No Kirchhoff voltage law	Kirchhoffs voltage law imposed	[unit]
Base	Avg electr. price = 32.87 Total supply = 288 Net exports = 25.1	Avg electr. price = 30.32 Total supply = 285 Net exports = 21.2	[EUR/MWh] [TWh] [TWh]
Elcert (new elcert production earns certificates)	Avg electr. price = 27.99 Elcert price = 31.96 Elcert tax = 3.19 Total supply = 312 Net exports = 47.6 ΔConsumer surplus = +0.62 ΔOld suppliers = -1.62 (-17%) New suppliers = +0.42 ΔTSO profit = +0.28 Social Welfare chg = -0.30 Certificates value = 0.84 Deadweight loss = 36%	Avg electr. price = 26.52 Elcert price = 32.41 Elcert tax = 3.23 Total supply = 303 Net exports = 37.8 ΔConsumer surplus = +0.27 ΔOld suppliers = -1.19 (-13%) New suppliers = +0.40 ΔTSO profit = +0.15 Social Welfare chg = -0.37 Certificates value = 0.86 Deadweight loss = 43%	[EUR/MWh] [EUR/MWh] [EUR/MWh] [TWh] [TWh] [Bill EUR] [Bill EUR] [Bill EUR] [Bill EUR] [Bill EUR] [Bill EUR] [percentage]
Cables (elcert production and increased integration from new cables)	Avg electr. price = 32.21 Elcert price = 26.56 Elcert tax = 2.68 Total supply = 314 Net exports = 52.7 ΔConsumer surplus = -0.50 ΔOld suppliers = -0.21 (-2%) New suppliers = +0.40 ΔTSO profit = +0.40 Social Welfare chg = 0.09 Certificates value = 0.70 Deadweight loss = (n.a.)	Avg electr. price = 26.44 Elcert price = 31.96 Elcert tax = 3.18 Total supply = 306 Net exports = 41.0 ΔConsumer surplus = +0.21 ΔOld suppliers = -1.14 (-13%) New suppliers = +0.40 ΔTSO profit = +0.49 Social Welfare chg = -0.04 Certificates value = 0.84 Deadweight loss = 5%	[EUR/MWh] [EUR/MWh] [EUR/MWh] [TWh] [TWh] [Bill EUR] [Bill EUR] [Bill EUR] [Bill EUR] [Bill EUR] [Bill EUR] [percentage]
Demand (elcert production, new cables and demand increase by 10% in Norway and Sweden)	Avg electr. price = 33.73 Elcert price = 24.97 Elcert tax = 2.30 Total supply = 314 Net exports = 27.7 ΔConsumer surplus = +0.67 ΔOld suppliers = +0.30 (+3%) New suppliers = +0.41 ΔTSO profit = +0.33 Social Welfare chg = 1.70 Certificates value = 0.66 Deadweight loss = (n.a.)	Avg electr. price = 31.68 Elcert price = 25.92 Elcert tax = 2.38 Total supply = 310 Net exports = 22.8 ΔConsumer surplus = +0.53 ΔOld suppliers = +0.46 (+5%) New suppliers = +0.38 ΔTSO profit = +0.27 Social Welfare chg = 1.64 Certificates value = 0.68 Deadweight loss = (n.a.)	[EUR/MWh] [EUR/MWh] [EUR/MWh] [TWh] [TWh] [Bill EUR] [Bill EUR] [Bill EUR] [Bill EUR] [Bill EUR] [Bill EUR] [percentage]

In

Figure 23 we break down the welfare redistribution effects for each price area in the *elcert* scenario without considering Kirchhoff's Voltage Law. We also include the TSO's profit change.

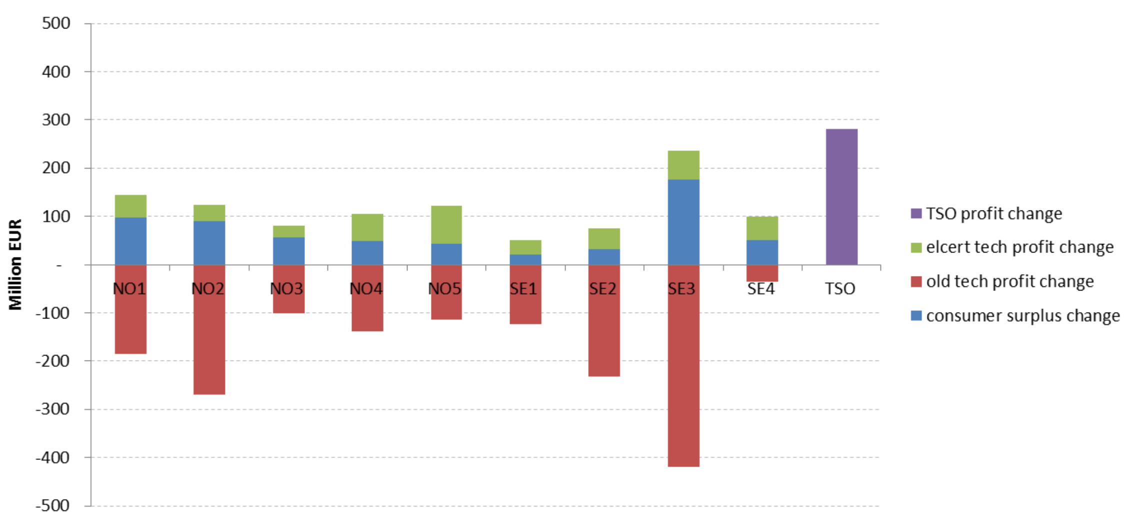

Figure 23 Geographical welfare redistribution effects comparing base and *elcert* scenario without considering Kirchhoff's Voltage Law

Figure 23 shows that existing producers lose and consumers gain, but we notice that the redistribution of welfare is different from area to area. In total we see that there are more negative than positive changes, indicating a deadweight loss for the scheme. Two regions have a positive aggregated welfare effect (NO5 and SE4), thanks to localization of new production facilities. In this scenario some of the old production is replaced by new certificate production. This leads to big profit losses in affected areas (production from old suppliers is reduced by 2.5 TWh in SE3). We notice that the TSO profit increases, due to increased power flows.

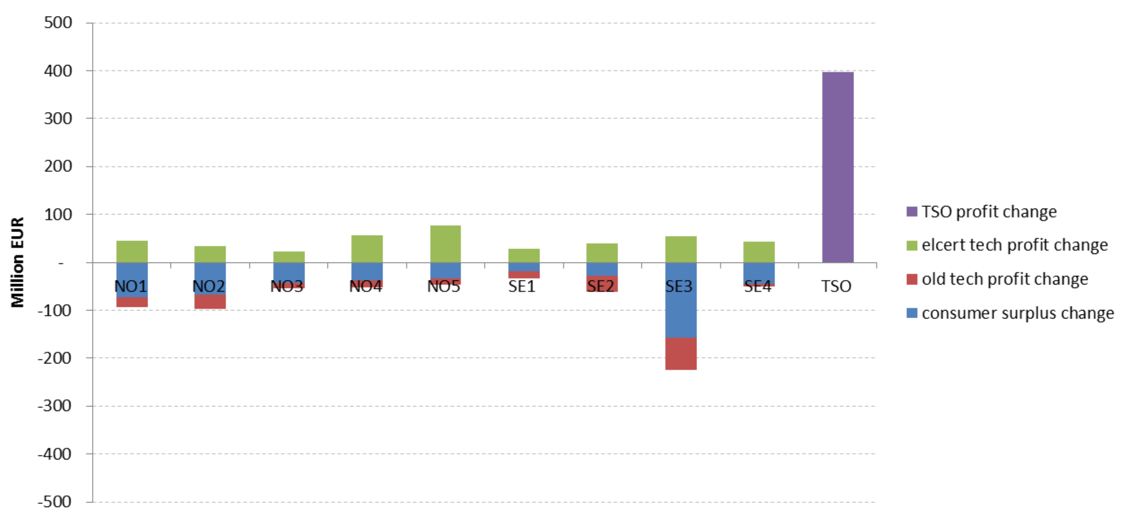

Figure 24 Geographical welfare redistribution effects comparing base and *cables* scenario (green certificate scheme and new cables towards Europe) without considering Kirchhoff's Voltage Law

The cables scenario reveals a different picture in Figure 24. Price changes are small in this scenario, so the welfare distribution changes are much smaller. Both consumers and old suppliers lose, in order to provide income to new suppliers. SE3 is the area with the by far highest electricity consumption, and the negative change in consumer surplus is only proportional to the use. NO4 and NO5 are the only regions with an increase in total welfare. The TSO profits from increased power flows, where Norway and Sweden are exporting high volumes towards Northern Europe. All in all this turns out as a rather balanced solution, with a small deadweight loss. Welfare is transferred from consumers and old suppliers to new suppliers and the TSO, and Europe is consuming the renewable electricity.

The solution to the demand scenario in Figure 25 shows yet another regional distribution. NO4, NO5 and SE2 are areas which increase their welfare in this scenario, while SE1 is in balance. Consumers bear the heaviest burdens in this scenario, and these are the four areas with the lowest consumption. High consumption areas suffer the biggest welfare losses in this scenario.

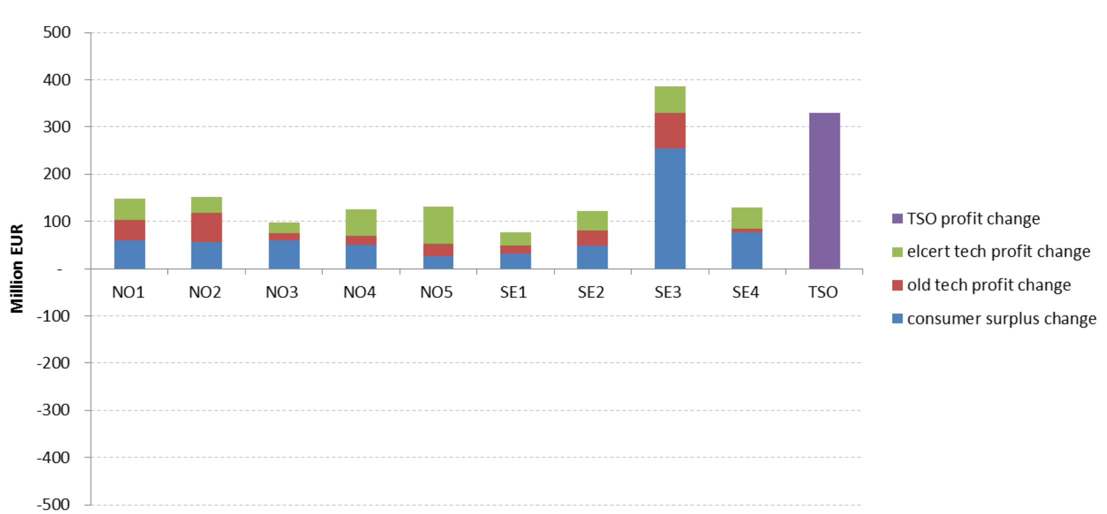

Figure 25 Geographical welfare redistribution effects comparing base and *demand* scenario (green certificate scheme with new cables and increased demand in Norway and Sweden) without considering Kirchhoff's Voltage Law

The geographical welfare distribution effects in the *elcert_kvl* scenario (with Kirchhoff's voltage law imposed) is presented in Figure 26. This scenario has considerable welfare transfers from existing suppliers to consumers in most areas, but not in NO1, NO2 and NO5. Electricity prices decrease in all price areas, but the green certificate tax makes consumers suffer from higher prices in East, South and West Norway. Only NO5 and SE4 have a positive net welfare effect in this scenario.

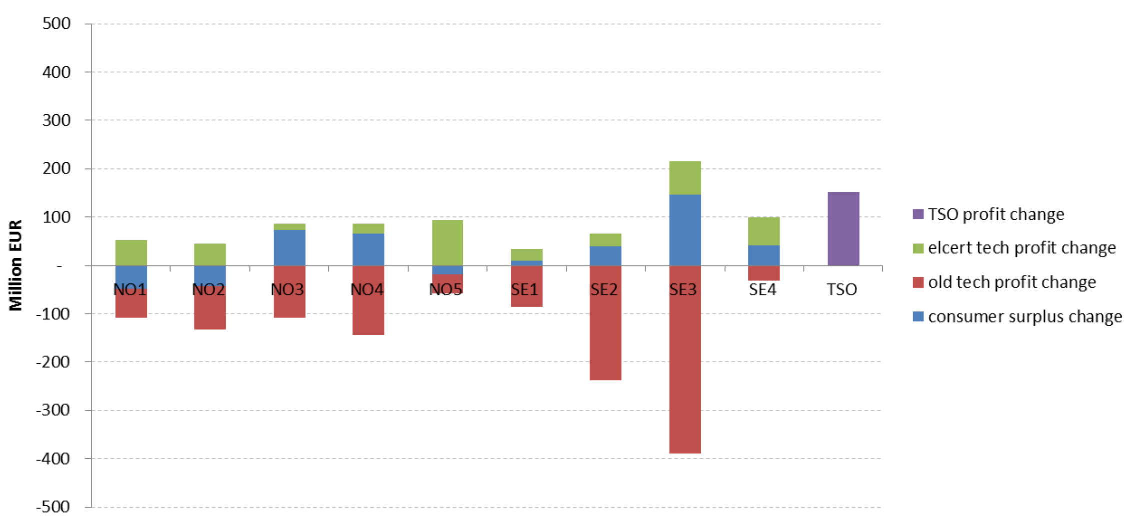

Figure 26 Geographical welfare redistribution effects going from base case to elcert scenario with Kirchhoff's Voltage Law imposed (*elcert_kvl* scenario)

In the *demand_kvl* scenario old producers profit increase due to higher prices. Higher prices make consumers lose, but consumer surplus increase in most areas due to the positive shift in the demand curve. Consumers in NO1, NO2 and NO5 lose (see Figure 27).

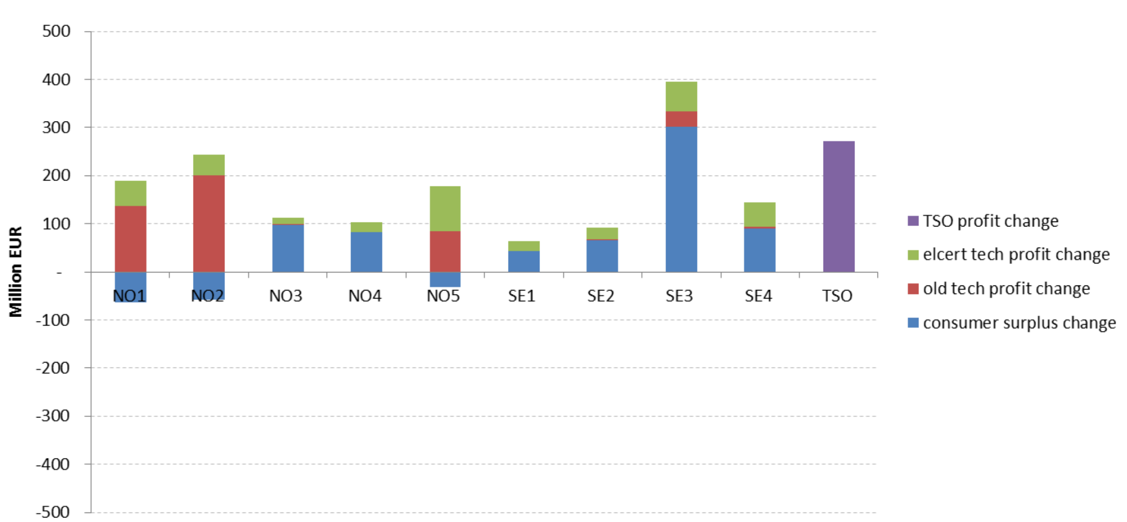

Figure 27 Geographical welfare distribution effects going from base case to elcert scheme with new cables and increased demand in Norway and Sweden with Kirchhoff's Voltage Law imposed (*demand_kvl* scenario)

Figure 28 shows selected technologies eligible for green certificates in SE3 and SE4, detailing certain aspects of Figure 15.

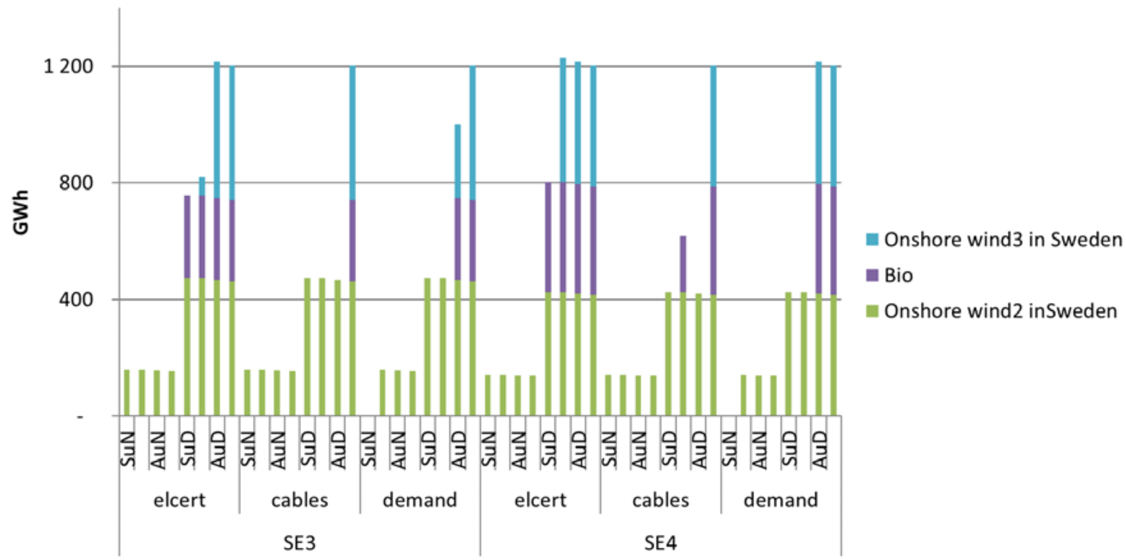

Figure 28 Certificate generation by region with Kirchhoff's Voltage Law imposed.

The figure shows that bio production is fully exploited in every time period when the more expensive wind production is used. Figure 28 also shows some small variations in production between time periods. There are two reasons for this:

1) Time periods have slightly different numbers of hours, resulting in different production quantities
2) Regulable hydro is shifted between periods and affect production levels in such timeslices.