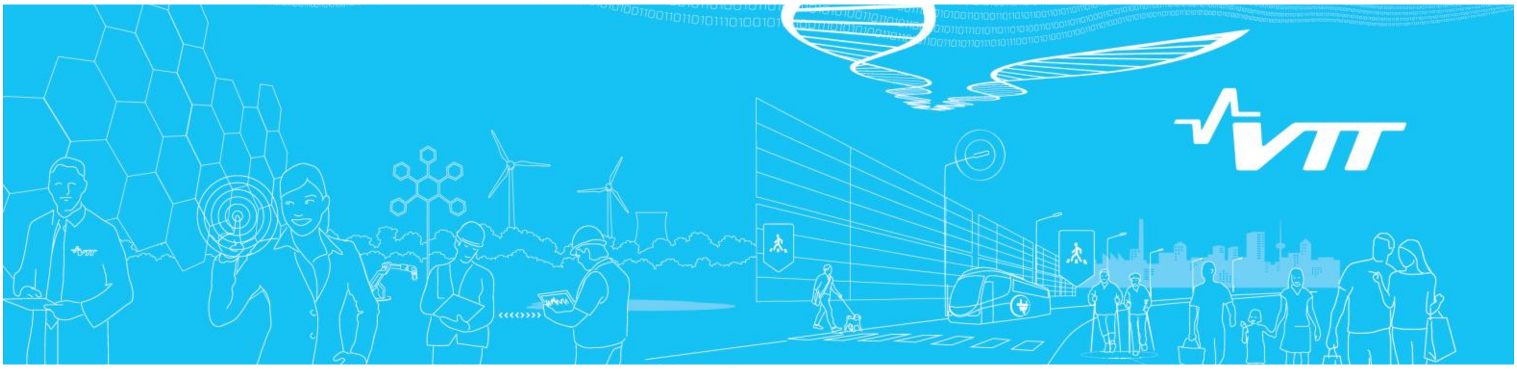

RESEARCH REPORT

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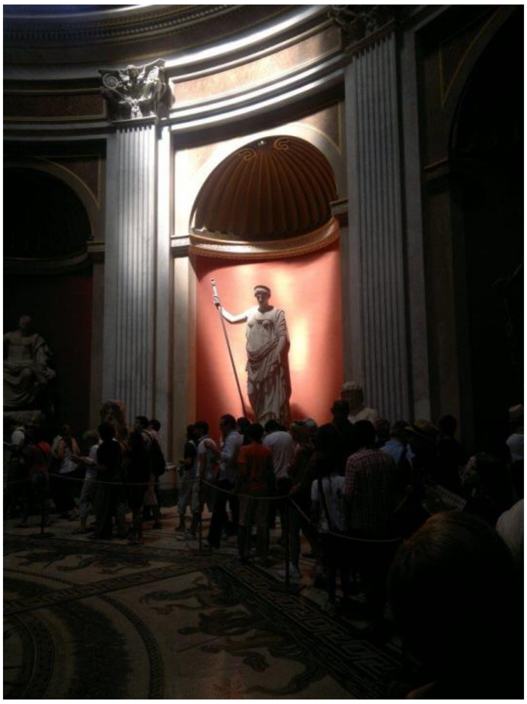

SGEM WT 7.2 FP5 Report D7.2.4

The capacity question in European power markets 2035

Authors: Göran Koreneff, Lassi Similä & Juha Forsström

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Summary

The report is the deliverable D7.2.4 of the Working Task 7.2 in the 4th and 5th funding periods in the Smart Grids and Energy Markets (SGEM) research programme.
This study approaches the power capacity question from various viewpoints. In the report, we first look at the related question of investment under uncertainty from theoretical viewpoint. The market price of electricity must stay for long periods on a much higher level than the average production cost before we can expect it to induce any new purely market-based investments.
We secondly look at different capacity mechanisms and especially at Britain's new capacity mechanism, which we analyse. Practical arrangements and numerical market data present added value to the more theory-oriented discussions on capacity markets in our previous SGEM report.
The Nordic market is one of the most advanced, if not the most advanced, power markets in the world. The wholesale market is mainly energy based, with special arrangements for reserve power (capacity). Our third focus lies on the question of how will new and especially adjustable regulating power capacity be induced to the Nordic market and what is the role of smart end-users?
The profitability of condensing power plants is seen as a key question related to need of capacity solutions. According to our simulations of the Nordic electricity markets, assuming the increase of electricity from renewable energy sources goes according to national plans, we see that condensing power production in the Nordic market in 2035 will dwindle to 4 to 6 TWh in a normal year, 1-2% of the demand. The market price of electricity in 2035 will not either support investments in condensing power capacity. If new condensing power capacity is needed for the short term management of intermittent wind power, and that is a big and interesting if, it has to be reimbursed otherwise. However, the alternative to new capacity, and capacity mechanisms, is Smart Grids and end-user flexibility. The Nordic countries have great opportunities for flexibility with a high heat demand and widespread district and electric heating, and vehicles might to some extent be electric by 2035.

Confidentiality	Public

Espoo 28.2.2015

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Preface

This work was carried out in the Smart Grids and Energy Markets (SGEM) research program coordinated by CLEEN Ltd. with funding from the Finnish Funding Agency for Technology and Innovation, Tekes. We also wish to thank all the SGEM partners, among others our work package manager Merja Pakkanen, with whom we have had a lively dialog.

This report is the deliverable 7.2.4 of Working Task 7.2 in the 4^{th}&5^{th} funding period of SGEM.

Espoo 28.2.2015

Authors

Contents

Abbreviations

BFB	Bubbling fluidised bed
CCGT	Combined cycle gas turbine
CCS	Carbon capture and storage
CFB	Circulating fluidised bed
CHP	Combined heat and power
CM	Capacity market
CMU	Capacity market unit
CONE	Cost of new entry
CWE	Central Western Europe
DECC	Department of Energy and Climate Change (GB)
DH	District heating
DSR	Demand side resources
EFC	Equivalent Firm Capacity
ETS; EU ETS	European trade system
EU	European Union
EV	Electric vehicle
FiT	Feed-in tariff
GB	Great Britain
GHG	Greenhouse gas
GW	Gigawatt, 1GW = 1000 MW
GWh	Gigawatthours, 1 GWh = 1000 MWh
IEA	International Energy Agency
IED	EU Industrial emissions directive
LCOE	Levelised cost of electricity
LOLE	Loss of load expectation
MCP	Medium-sized combustion plant directive
MW	Megawatt
MWh	Megawatthours
NOx	Nitrogen oxides
MSW	Municipal solid waste
OCGT	Open cycle gas turbine
Ofgem	Regulatory agency of the electricity and gas markets (GB)
ORC	Organic ranking cycle
PV	Photovoltaic
RDF	Refuse-derived fuel
RES	Renewable energy sources
RES-E	Electricity from renewable energy sources
SGEM	Smart Grids and Energy Markets research programme
SOx	Solid oxides
TIMES-VTT	VTT's partial equilibrium model of the global energy system
TWh	Terawatthour, 1 TWh = 1 000 000 MWh
VAT	Value added tax
WEC	World Energy Council
VTT-EMM	VTT's Energy Market Model

1. Introduction

1.1 Goal

The report is the deliverable D7.2.4 of the Working Task 7.2 in the 4th and 5th funding periods in the Smart Grids and Energy Markets (SGEM) research programme.

One of the main objectives of this task is to describe the possible European electricity market development to 2020 and 2035, especially related to new capacity, but also how active resources – whose significance are expected to rapidly increase by Smart Grids - fit in.

The most influential drivers include the European Union’s climate change mitigation policies, energy market integration policy and the drive towards security of supply while retaining the EU’s competitiveness.

The climate change mitigation policies in the EU are constantly developing. By 2020, the target is to reduce greenhouse gas emissions by 20%, increase the use of renewable energy sources (RES) to 20% and to improve energy efficiency with 20%. The target for 2030 is still under work, but the EU has already indicated a reduction of greenhouse gases by 40% and an increase of renewable energy sources to 27% (which will not be delegated to national level targets). The long term target is to reduce greenhouse gases with 80% to 95% by 2050.

New electricity production from RES, RES-E, is introduced to the European markets with all kinds of subsidies. In the Nordic market feed-in tariffs (FiT) and electricity (green) certificates together with investment supports are the main tools. Large amounts of new variable or intermittent production is putting a stress on conventional condensing power plants: their profitability decreases. How will we manage to uphold the regulable capacity fleet needed for the future and how will Smart Grid features influence the amount of capacity needed? We’ll estimate the development of the Finnish and Nordic market prices to 2035 and assess what it means for existing and new capacity.

1.2 Description

The Nordic market is one of the most advanced, if not the most advanced, power markets in the world. There is an abundance of market actors, sellers and buyers, in the wholesale and retail markets. The power system is operated as neutrally as possible and with the whole market in mind. The wholesale market is mainly energy based, with no remuneration for capacity, so the big question is, how will new and especially adjustable regulating power capacity be induced to the market and what is the role of smart end-users?

This study approaches the *capacity question* from various viewpoints. In the report, we first look at the related question of investment under uncertainty from theoretical viewpoint. We then turn to our second focus, capacity mechanisms. We have looked closely at different capacity mechanisms in our previous SGEM report (Koreneff et al. 2014) and at what benefits and what disadvantages they have. Britain has now introduced a capacity mechanism, which we analyse here. Practical arrangements and numerical markets data present particular added value to those more theory-oriented discussions on capacity markets in our previous SGEM report.

The third research focus point is to assess the overall demand and supply developments towards 2020 and 2035, with closer attention on the Nordic and Finnish situation, and to especially assess the future (wholesale) market price. We’ll compare the market price to levelised cost of electricity of different production types, using various sources. Are market based investments possible? What will it mean for the Nordic or the Finnish capacity adequacy and market flexibility, and how do the Smart Grid features fit in?

2. Investment under uncertainty

This Chapter builds on Pindyck's and Dixit's seminal book about Investment under uncertainty (Dixit & Pindyck 1994). Here we are going to describe the issue in qualitative terms. Those who are interested in the rigour, mathematical treatment of the subject are advised to read the well written book.

Most investment decisions share three important characteristics in varying degrees. These are *irreversibility, uncertainty* and *timing*. Irreversibility means that the investment is partially or completely sunk: you cannot recover it all if you change your mind later. Uncertainty refers to the future rewards from the investment. You can only assess the probabilities of the alternative outcomes that can mean greater or smaller profit for your venture. Finally, you may have some leeway in choosing the date of actually making the investment. You may postpone an action to get more information about the future – a complete certainty is, however, impossible.

2.1 The standard approach

How should a firm, facing uncertainty over future market conditions, decide whether to invest in a new power plant? A standard rule to apply in these situations is as follows: First, calculate the present value of the expected profit stream that this plant will generate. Second, calculate the present value of the stream of expenditures required to build up the plant. Finally, determine whether the difference between the two, namely the net present value (NPV) of the investment, is greater than zero. If it positive, go on and invest.

2.2 The options approach

The net present value rule implicitly assumes that *either* the investment in reversible *or*, if the investment is irreversible, it is a now or never case.

Reversibility means that the investment can somehow be undone and the expenditures recovered should market conditions turn worse than anticipated. The now or never proposition means that if the firm does not undertake the investment now, it will never be able to in the future.

Most investments do not meet these conditions. A firm with an opportunity to invest is holding an option analogous to a financial call option – it has the right but not the obligation to buy an asset at some future time of its choosing. When a firm makes an investment it exercises its option to invest. It gives up waiting for new information to arrive that might affect the desirability or timing of the expenditure. This lost option value is an *opportunity cost* that must be added to the cost of investment. The value of the new plant must exceed the purchase and installation cost by an amount equal to the value of keeping the investment option alive.

The option value is highly sensitive to uncertainty over the future value of the project so that changing economic conditions that affect the perceived riskiness of future cash flows can have a large impact on investment spending. This impact can be larger than a change in interest rates. This may help to explain why neoclassical investment theory has so far failed to provide good empirical models of investment behaviour, and has led to overly optimistic forecasts of the effectiveness of interest rate and tax policies in stimulating investment. In practice, firms do not invest until price rises substantially above the long-run average cost.

Various sources of uncertainty about future profits – fluctuations in product prices, input costs, exchange rates, tax and regulatory policies – have much more important effects on investments than does the overall level of interest rates.

2.3 Industry equilibrium

Consider a firm contemplating its investment and knowing that there are many other firms facing similar decisions with similar uncertainty. The firm is ultimately concerned with the consequences of its decision for its own profits but it must recognize how the similar decisions of other firms will affect it. In this respect, two types of uncertainties must be distinguished because they can have different implications for investment: aggregate uncertainty that affects all firms in the industry and firm-specific uncertainty facing each firm.

Consider an industry-wide increase in demand. Any one firm expects this to lead to a higher price, and so improve its own profit prospects, making an investment more attractive. However, it knows that several other firms are making a similar calculation. Their supply response will dampen the effect of the demand shift on the industry price. Therefore the upward shift of its own profit potential will not be quite as high as in the case where it is the only firm and has a monopoly on the investment opportunity.

When the investment is totally irreversible, a downward shift in industry demand has an unfavourable effect. Even though other competitive firms are just as badly affected they cannot exit (irreversibility) to cushion the fall in price. Thus the competitive response to uncertainty has an inherent asymmetry: the downside exerts a more potent effect than the upside. This asymmetry makes each firm cautious in making the irreversible investment.

When there is some reversibility the exit of other firms does cushion the effect of adverse demand shocks on price. But then each firm’s exit decision recognizes this asymmetric effect of demand shocks in an initially poor situation: their upside effect is more potent than the downside. Thus competitive firms are not quick to leave when they start to make operating losses. They wait a while to see if things improve or if their rivals exit.

Firm-specific uncertainty does not lead to this kind of asymmetry: In industry equilibrium it leads to investment decisions similar to those of an isolated firm.

2.4 Suspension and abandonment

If a loss making plant can be temporarily suspended and resumed later when it becomes profitable again, then the plant forms a sequence of operating options. Their value must be found, discounted and aggregated. The investment opportunity itself is then an option to acquire this compound asset.

Temporary suspension is not possible if a live project has quickly disappearing capital when the project is not kept in operation. Then a permanent abandonment is the only alternative to continuous operation. If the firm decides to restart, it has to reinvest in all the assets. Abandonment may have a direct cost, e.g. workers may have to be given severance payments. But what is even more important is an opportunity cost: the loss of the option to preserve the capital so that it can be used profitably if the circumstances improve. Therefore, a firm with a project in place will tolerate some losses to keep this option alive, and only sufficiently extreme losses will induce it to abandon.

Here we have an interlinked pair of options. When the firm exercises its option to invest, it gets a project in place and an option to abandon. If it exercises the option to abandon, it gets the option to invest again. The two options must be priced simultaneously to determine the optimal policy of investment and abandon. This linkage has important implications, e.g. a higher cost of abandonment makes the firm even more cautious about investing, and vice versa.

2.5 Entry, exit and average prices

The standard theory says that firms will enter the industry if the price rises to equal the long-run average cost and they will exit if price falls as low as the average variable cost. When uncertainty is taken into account a wider range of price variation on either side is needed for entry and exit to happen.

For example, in the face of aggregate uncertainty, the long-run average cost will not constitute industry equilibrium. Each firm knows that entry of other similar firms will stop the price from ever rising any higher, while future unfavourable shifts can push the price below this level. Also, a future price path that sometimes touches the long-run average cost and otherwise stays below this level can never offer a normal return on the firm's investment. Only if the price ceiling imposed by entry is strictly above the long-run average cost can the mix of intervals of supernormal profit and ones of subnormal profit average out to a normal return. Similarly, firms will exit only when the price falls sufficiently far below the average variable cost. They will tolerate some losses, knowing that the exit of other firms puts a lower bound on the price. The equilibrium level of this floor is determined by averaging out the prospects of future losses and profits to zero.

The competitive equilibrium under uncertainty is not a stationary state even in the long run, but a dynamic process where prices can fluctuate quite widely. Periods of supernormal profits can alternate with periods of losses. For example, substantial periods of supernormal profits without new entry can occur even though all firms are small price takers.

2.6 Hysteresis

A firm's optimal decision on investment and abandonment is characterized by two thresholds. A sufficiently high level of profit corresponding to an above-normal rate of return on the sunk cost justifies investment and a sufficiently high level of loss leads to abandonment. When the current level of profit is somewhere between these two thresholds the existence of an active firm depends on history of profit fluctuations. If the profit has recently descended from a high level that induced entry, then there will be an active firm. But if the profit level has recently risen from low levels that induced exit, then there isn't an active firm. This means that the current level of profits does not suffice to explain the outcome in an economy, a longer history is needed, i.e. the economy is *path dependent*.

2.7 Electricity market connexion

All the above is applicable in electricity markets: price level corresponding to average production cost does not induce investments. Prices must stay long periods on a much higher level before we can expect any new purely market-based investments to appear. This is not good news for an electricity consumer.

In Nord Pool the majority of production is based on hydro and nuclear power, complemented by wind power and combined heat and power production. Conventional condensing has only a tiny market share. Wind power's market share is on the rise and that trend is going to last for the next decade, at least.

The industry equilibrium of the power generation sector is experiencing disturbances from policy based and outside the market funded new entries, i.a. subsidised wind power, which is equivalent to a downward shift in industry demand resulting in more uncertainty and more cautiousness than before to investments in unsubsidised power capacity.

Simplifying a little we can say that the higher the share of generation forms having zero emissions and very low variable costs, i.e. hydro, nuclear, wind and PV, the lower the spot market average price of electricity. The lower the market price, the less inclination the industry will express in investments in intermediate or peak capacity having comparably high variable costs.

3. Capacity mechanisms

Capacity mechanisms were studied at depth in the previous SGEM report (Koreneff et al. 2014). A brief general overview of capacity mechanisms is given here. There have been several developments after that, e.g. the introduction of a capacity mechanism in Great Britain, which will be studied in more detail.

A variety of design options are available for capacity mechanisms and capacity markets. However, theoretically, a capacity market can be fundamentally described as a mechanism to transfer the shadow price of the reserve margin constraint to capacity owners (Allcott 2012). The reserve margin can be, say, around 15% of the estimated peak demand. However, capacity mechanisms must be looked at more broadly as already the Capacity Market in Great Britain shows, or the fact that Finland's production capacity is already below the estimated peak demand. Capacity mechanisms are not only about remunerating reserves that are almost never used in a market, they are mechanisms that bring capacity to the market or keep capacity in it where this would not otherwise happen, a question more than ever topical in the wake of huge capacity amounts or electricity from renewable sources such as wind or PV introduced to the electricity markets.

If we just talk of reserves in excess of the peak demand, that is, capacities not used normally in a market, they can well be seen as an system operation issue, not a market operation issue, and be organised outside the market, the Swedish and Finnish strategic capacity reserves coming to mind here.

We also look at capacity mechanisms from different market perspectives: Finland, the Nordic countries, selected other markets. Do the markets and market systems require capacity mechanisms and how would they manage without them? Can we get new marginal controllable generation capacity on a market basis, and do we need it?

3.1 Capacity mechanisms –an overview

Capacity mechanisms are a regulatory intervention to compensate generators for the capacity needed to give the consumers the standard of security that they would (collectively) like. Characteristics of electricity as a product, such as lack of price-responsive demand, limitations in storing the product and its consecutive exposure on market power during times of high demand are main factors behind the rather exceptional discussion on capacity mechanisms within electricity sector, as thoroughly discussed in Koreneff et al. (2014).

Typically, capacity mechanism organiser, e.g. system operator or regulatory body affects the outcome of the mechanisms directly or indirectly. This can be done either by determining the payment or an amount of capacity to be auctioned. Capacity mechanisms can take many forms and designs, as many different capacity mechanism designs have been implemented and/or are under discussion throughout the world.

Capacity **markets** are a market-oriented way for capacity mechanism, That is, they can be described as a marketplace which set a price for capacity units according to their supply and demand. Basic design features of capacity markets can be divided as in Cramton & Ockenfels (2011).

- Determining the need of adequate capacity
- Product design

- Auction design

Table 1 demonstrates the challenges and complexity of designing capacity markets. In each design parameter, there are several trade-offs and choices to be made.

Table 1. Capacity market parameters. Source: Baritaud (2013), adapted from Hogan.

Capacity definition	*Peak generators, dispatchable plants, intermittent sources, demand response*
Horizon and duration	*Annual to multiple years, period of capacity availability (definition of peak period)*
Capacity Requirements	*Uncertain demand forecasts, coherence with reliability standards*
Network constraints	*Definition of locational capacity requirements*
Cost of New Entry	*New power plant, mothballed plants, power uprate, demand side*
Energy Revenues	*Ex ante or ex post determination*
Capacity Demand Curves	*Fixed capacity requirements vs variable demand slope to smooth revenues*
Capacity Cost Recovery	*Suppliers or socialized payments*
Penalties	*Control of availability, outage rates, penalties*

Here, we take a look at British solution in a context of capacity mechanisms, see e.g. National Grid (2014). The theoretical framework of capacity mechanisms is more specifically described in Koreneff et al. (2014).

3.2 The British capacity mechanism

After finalisation of the report Koreneff et al. (2014), the first capacity market auction under the developed design in Great Britain (GB) was conducted. Here, we take a deeper look on practices, functioning, and results of the capacity markets based on the specific GB example. Actual, numerical results give the SGEM research program a valuable addition to those more theory-oriented discussions on capacity market, as in Koreneff et al. (2014)

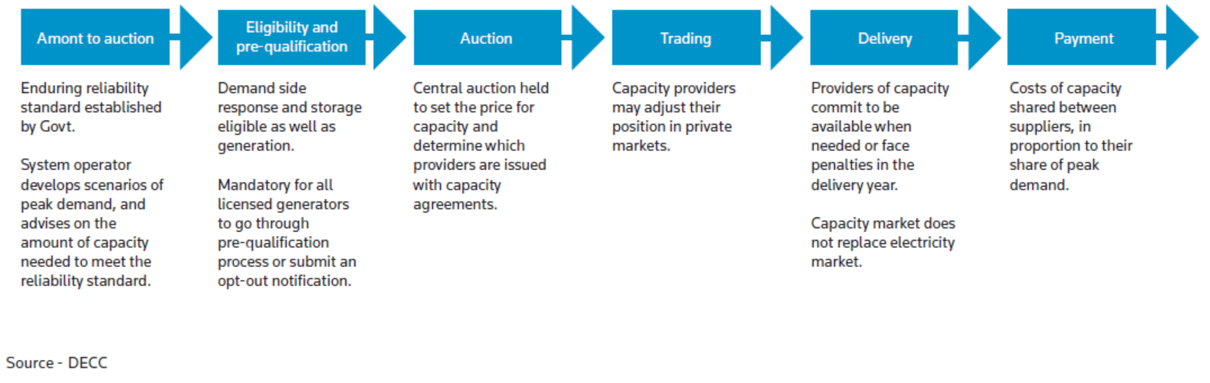

Figure 1 Overview of the British capacity market. (Source: Phillips & Patel 2014)

Figure 1 presents the key building blocks of the British capacity market. The first auction run in late 2014 for a delivery period four years ahead (“T-4” auction), i.e. winter 2018/19. The auction closed on 18 December 2014. It is of importance to stress that the capacity mechanism does not replace the electricity market but is supplementary to it.

The British auction format is a so called descending-clock auction (see Figure 2 for schematic presentation). That is, the auctioneer starts the auction from a predefined price cap and lowers the price round by round until the desired quantity is selected. All the selected capacities are paid the clearing price for their corresponding amount if they are successfully available (pay as clear -auction).

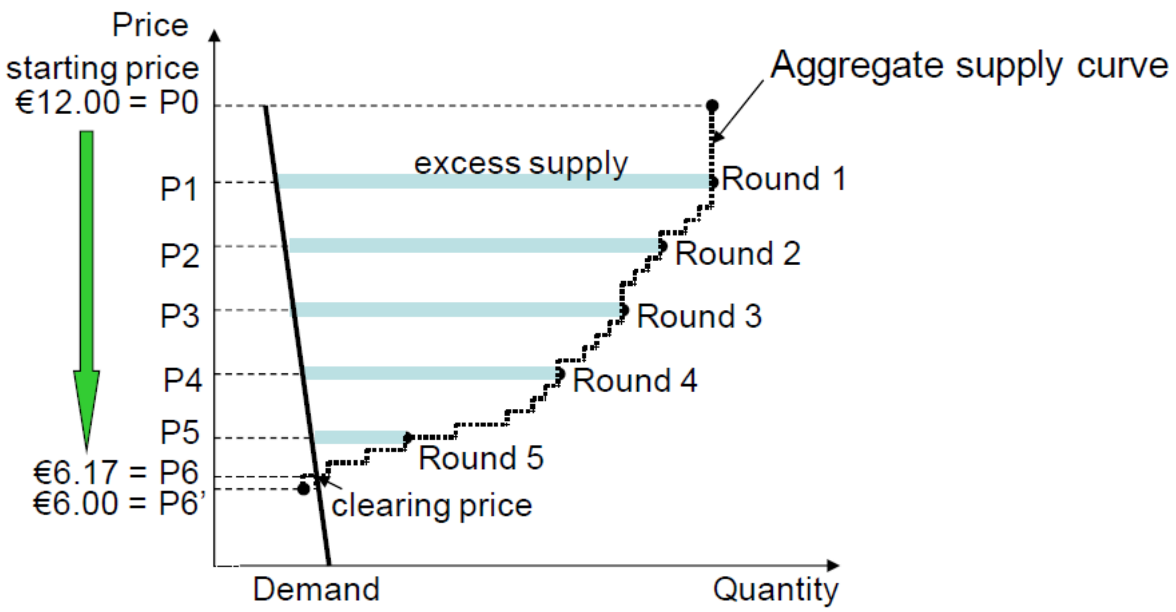

Figure 2. Descending clock auction. (Source: Cramton & Ockenfels 2011)

3.2.1 Capacity definition

In the British capacity market, all capacities are eligible for bidding except capacities receiving named supports, e.g feed-in tariffs. That is, no pre-defined restriction is made to e.g. peaking plants. The amount of capacity to be contracted is based on System Operator’s (consulted with DECC[1] and Ofgem[2]) analysis taking into account a reliability standard, measured by loss of load expectation. The analysis takes into account availability of technologies using de-rated capacity margins (the average excess of available generation capacity over peak demand, expressed in percentage terms) to diversify the differences between types of capacities (National Grid 2014).

Also, new capacities, as well as existing and refurbishing projects to increase capacity are allowed for bidding. However, there are restrictions for bidding to mitigate market power of existing power plants. That is, bidders will be classified as either ‘price takers’ (who cannot bid above a relatively low ceiling) or ‘price makers’ (who can). Existing plants will be classified as price takers, and new entrants and demand side resources (DSR) resources will be classified as **price makers**, and they are free to bid up to the overall auction price cap.

Figure 3 presents an illustrative supply curve, where it is seen that price setters determine the capacity market price.

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[1] Department of Energy and Climate Change
[2] Ofgem: regulatory agency of the electricity and gas markets in Great Britain

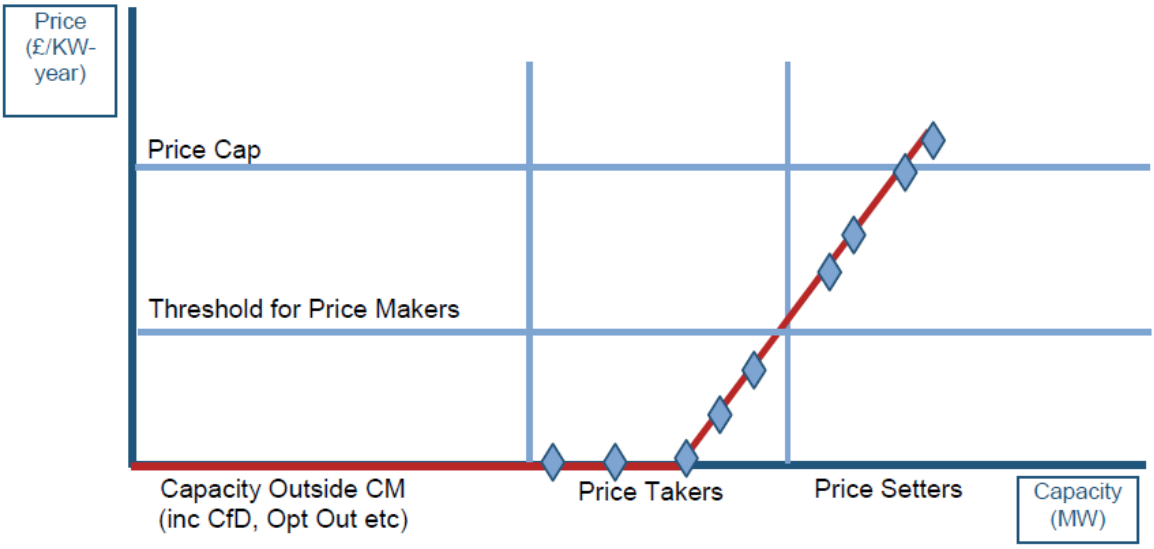

Figure 3. Illustrative supply curve of the British capacity market. (Source: Allen & Overy 2013)

For 2014 auction, the overall **price cap** was set at £75 per kW (Phillip & Patel 2014). The cap is determined by 1.5 x net CONE. Net CONE (Cost of New Entry) is the estimate of the reasonable cost of new capacity. It is determined from the cost of a new build open cycle gas turbine (OCGT) plant minus expected electricity market revenue. The cost of OCGT capacity is used to set CONE is because it being a marginal plant – the one that most needs a capacity payment (because it runs least) (DECC 2013).

De-rated capacity corresponds to the amount of reliable capacity to be eligible for bidding. Its assessment is based on historical performance etc. For example, nuclear plants are granted a de-rating factor of 81.39%, whereas OCGT gas turbines a factor of 93.61%. See examples of de-rating factors from Table 2.

Table 2. De-rating factors for the British capacity auction (Source: National Grid 2015)

Name for technology class	Plant Types Included	De-rating factor
Oil-fired steam generators	Conventional steam generators using fuel oil	82.10%
OCGT and reciprocating engines (non-autogeneration)	Gas turbines running in open cycle fired mode Reciprocating engines not used for autogeneration	93.61%
Nuclear	Nuclear plants generating electricity	81.39%
Hydro	Generating Units driven by water, other than such units: (a) driven by tidal flows, waves, ocean currents or geothermal sources; or (b) which form part of a Storage Facility	83.61%
Storage	Conversion of imported electricity into a form of energy which can be stored, the storing of the energy which has been so converted and the re-conversion of the stored energy into electrical energy Includes hydro Generating Units which form part of a Storage Facility (pumped storage hydro stations).	97.38%
CCGT	Combined Cycle Gas Turbine plants	88.00%
CHP and autogeneration	Combined Heat and Power plants (large and small-scale) Autogeneration – including reciprocating engines burning oil or gas	90.00%
Coal/biomass	Conventional steam generators using coal or biomass	87.64%
DSR		89.70%

Interestingly, no factor is given for wind or solar resources, whose generation is intermittent and who are currently generally dependent on subsidies. However, according to National Grid (2014), when considering intermittent renewable plants, National Grid looks to their expected contribution to security of supply, and there are no indications of their explicit forbiddance in the capacity markets. For wind, for example, the expected contribution for security of supply is achieved by considering a history of wind speeds observed across GB and running a number of simulations to determine its expected contribution. This concept is referred to as Equivalent Firm Capacity (EFC), and it is stressed that this concept is different from expected availability during peak periods.

Also, any generation capacity whose total capacity is under 2 MW is not eligible for the Capacity Market (CM). Furthermore, small scale renewable technologies are assumed to receive FiT support and are thus not eligible for entry into the Capacity Market. (National Grid 2014). These factors provide reasoning for the missing small-scale renewable production in Table 2.

3.2.2 Horizon and duration

The first auction was run four years ahead of the year capacity must be delivered, i.e. auction arranged in December 2014 concerns winter 2018/19 ("T-4" auction). Secondary auctions are scheduled to be run one year before delivery ("T-1" auction), and they are intended for updating the positions of T-4 auctions to represent the most recent information and also to attract bidding of demand side resources. This might be meaningful due to the fact that availability of demand side resources up to several years ahead might contain uncertainty. Also, according to Allen & Overy (2013), it is envisaged that DSR will participate in 1-year auctions, fully run for the first time in 2017 but there are plans for transitional arrangements before the first full auction is run, that is, specific DSR auctions to be run in 2015 and 2016.

New build generating CMU's are awarded with 15-year contacts, the existing units with one-year-contracts, and refurbishments with 3-year contracts. (Phillips & Patel 2014)

The British capacity mechanism is not intended to be necessarily permanent, but its necessity is reviewed on regular basis, according to Allen & Overy (2013), every five years.

3.2.3 Capacity requirements

The amount of capacity to be contracted is based on authorities' analysis. National Grid's recommendation to Government is based on its future energy scenarios and a reliability standard of no more than 3 hours of loss of load expectation (LOLE) per year.

The analysis (National Grid 2014) end up in recommendation is that Government procures capacity (before adjustments) within a range between 51.4 GW to 53.3 GW. Compared to estimated peak load differing from 58.8-60.5 GW in 2018/19 between the scenarios, and peak capacity between 83-86 GW, it is evident that not all the capacities needed are covered with capacity contracts. The Government has confirmed that it will procure a total of 53.3 GW of electricity generating capacity, which equates to more than 80% of the peak electricity use in Britain today (Phillips & Patel 2014). This amount covers all the scenarios and sensitivities developed in National Grid (2014). The difference between procurement plans and actual peak load can be explained by volumes not eligible for Capacity Markets and imports.

3.2.4 Network constraints

The way of how network constraints are taken into account is widely referred in a context of capacity mechanism. That is, from the network reliability point of view, network constraints, if active, may have an effect on beneficiary of particular capacity. Thus, different means to take this into account, such as dividing the market into local sub-areas, are among options. In Britain's solution, the whole area is dealt with as a single market. However, the System Operator will have the capability to run zonal auctions if necessary to manage constraints, but no such zones will be created unless approved by Ofgem (DECC 2013).

Imports via the European continental interconnectors are another factor to be considered in designing capacity mechanisms for Great Britain. In GB, interconnectors will be allowed to participate in year 2015's auction. This has the potential to add materially to potential capacity bidding into the auction. However, in reality the materiality of the impact of allowing interconnectors to participate will depend on how they are de-rated. (Frontier Economics 2015)

3.2.5 Cost of New Entry

Cost of New Entry (CONE) is defined for setting a price caps for bids from existing and new generators. This parameter is also defined and in use in GB's mechanism. In the auction, an estimate of 49,000 £/MW/yr was used. The figure is based on the net CONE of OCGT plant.

In determination of Net CONE, expected electricity market revenues are taken into account. This is probably done in order to avoid unnecessary double-payments.

3.2.6 Energy Revenues

Capacity market revenues in GB are separate. The capacity market is an additional mechanism in relation to electricity markets, and they do not seem to have direct dependence on energy revenues unlike cases in some other capacity mechanisms, such as traditional capacity payments.

3.2.7 Capacity Demand Curves

Instead of vertical demand curves, smoothed demand curves are used in GB's capacity auctions. Smoothing the demand of capacity reflects a trade-off between cost and reliability. That is, based on the target level from National Grid's analysis, the demand curve is smoothed. Due to the smoothness, there is some flexibility in the procured volumes as the realization is not necessarily perfectly identical to that assessed in the National Grid's analysis. This phenomenon is illustrated by Figure 4.

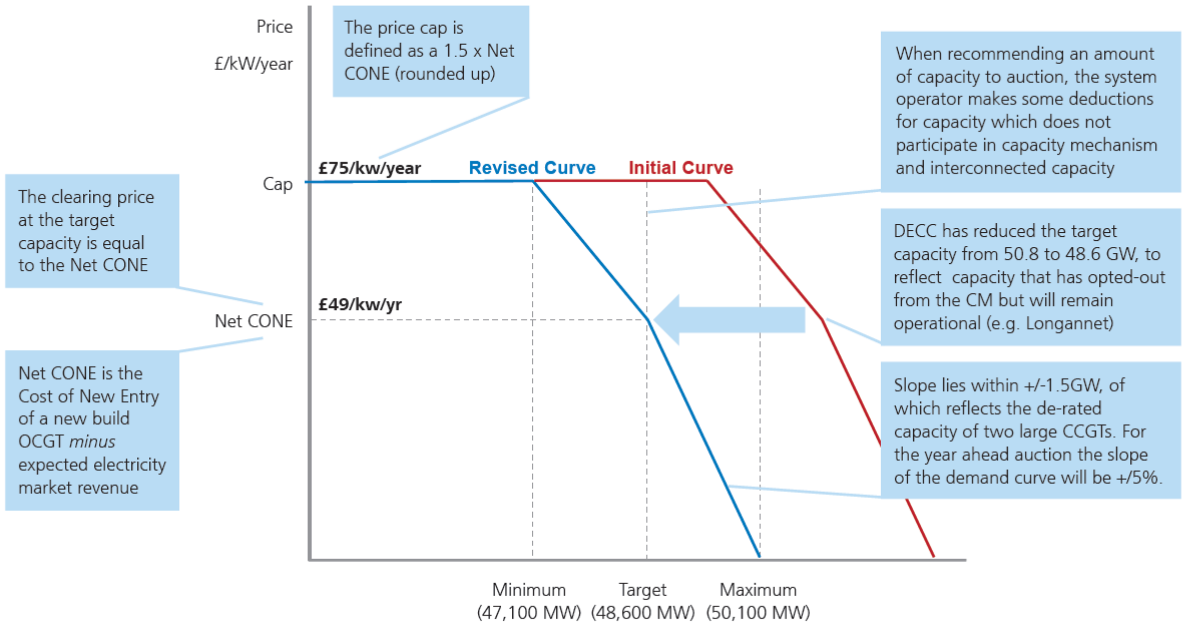

Figure 4. Britain's "kinked" demand curve. (Source: Anstey & Schönborn 2014)

3.2.8 Capacity Cost Recovery

The amount of capacity to be contracted is based on authorities' analysis, and the contracted capacities are paid by the clearing price of the auctions. This sum is allocated to electricity users through electricity suppliers according to their proportion of peak demand.

3.2.9 Penalties

"Capacity warnings" are declared 4 hours before delivery. In case of non-availability, penalties are obliged to participants who hold capacity commitments. According to the document[3], a settlement period of half an hour determines the penalties if a selected capacity

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3 https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/209280/15398_TSO_Cm_8637_DECC_Electricity_Market_Reform_web_optimised.pdf

delivering party is not able to deliver the committed volumes. Decision on whether a capacity provider has met its obligation will be based on the delivery of energy (by generating or reducing demand), or provision of a balancing service, during that period.

"The penalty rate for an obligation will be set at 1/24th of the relevant auction clearing price adjusted for inflation. So as not to disincentive participants, penalties will be capped at 200% of a plant's monthly income and 100% of its annual income". (Phillips & Patel 2014)

3.2.10 Results of the first auction

The clearing price of the first auction ended up in £19.40 per kW. Thus, this price will be paid to all successful participants for providing available capacity in winter 2018/19. The cost of providing these payments will be charged back to consumers through their electricity bills with the total cost expected to be £956 million in the first year. For average household, the average gross cost of this is estimated to result in £11.40 a year in 2018/19 (in 2014 prices). If an assessed decrease of electricity price caused by capacity is further taken into account, according to Government's estimate, the average annual net on domestic electricity bills over the period 2016 to 2030 might end up even as low as £2 a year, equivalent of 0.3 % average increase in domestic bills[4].

Just as a curiosity, if a similar strike price were used in Finland, and all the costs calculated per consumption in Finland, the domestic electricity bill would increase with roughly 5 €/MWh (incl. VAT).

In a report[5] by National Grid, the results of the first T-4 auction concerning winter 2018/19, are presented in detail. Government purchased 49.26 GW (derated) capacity. 64% was existing capacity, 14% refurbishments, 16% pre-refurbishment, 5% newbuilds, and 1% demand-side resources.

By technologies, 45% of the awarded capacity (by GW) was CCGT (Combined Cycle Gas Turbine) plants, being the largest technology category. For nuclear power plants, the awarded volume was 7.9 GW. Number of awarded units, 16, corresponds to the British nuclear fleet as a whole[6]. The awarded volume, 7.9 GW, also corresponds to the net capacity of fleet, 10 GW, almost totally, as de-rating factor is taken into account. Thus, it seems that all the nuclear plants in GB have taken part in the first capacity market and also being awarded by capacity contracts in the auction.

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[4] https://www.gov.uk/government/news/first-capacity-market-auction-guarantees-security-of-supply-at-low-cost

[5] https://www.emrdeliverybody.com/Shared%20Documents/Final%20Auction%20Results%20Report_v3.pdf

[6] www.world-nuclear.info

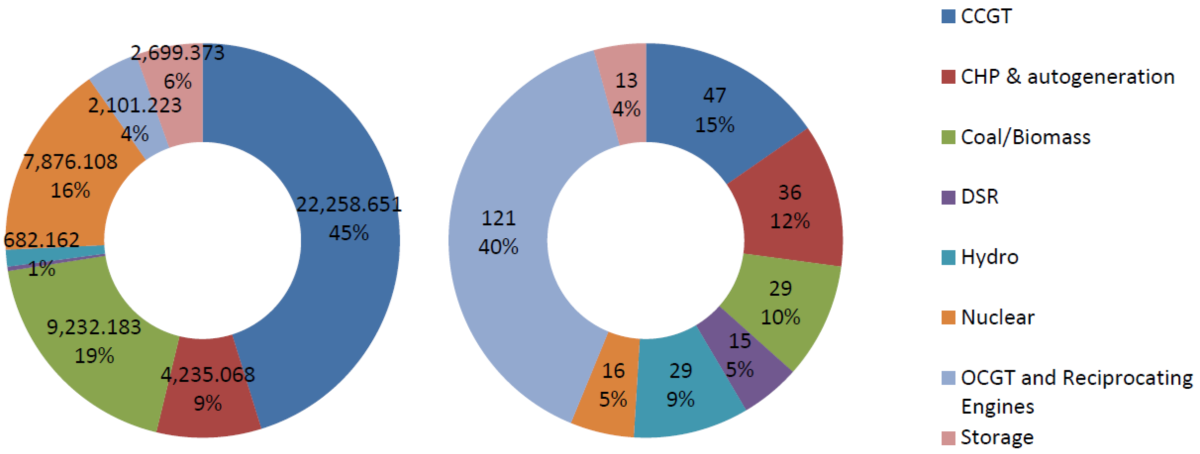

Figure 5. Breakdown of awarded capacity by technology type. The left-hand side figure presents that by GW whereas the right-hand side figure by number of awarded units. (Source: National Grid 2015).

3.3 Smart Grids and active end-users

How do Smart Grids, being a central piece of the SGEM program, interact with the capacity question approached in this report? Smart Grid technologies have potential to move electricity markets in the direction of ideal markets. That is, as more real-time measurements, information, and more active demand side can be introduced in the future electricity markets thanks to Smart Grid technologies, traditional weaknesses of electricity markets, such as lack of demand side flexibility, can be improved.

As another approach, capacity mechanisms aim to tackle the electricity shortcomings – more or less – by regulatory intervention. The effects of increasing renewable electricity on the electricity system and on the profitability of conventional plants can be seen as the main driver for the current discussion on capacity question in the EU. However, flexibility to meet intermittent electricity production from renewables can be managed to a quite extensive degree through existing and coming active end-users. System studies (DLR et al. 2012) related to the Energiewende in Germany assumes that heat systems, together with electric vehicles, will be the primary source of flexibility needed for the introduction of even more wind and PV. It is just towards 2050 that more drastic solutions such as power-to-gas will be needed en masse. Nevertheless, system studies do not take into account that utilities won't uphold power plants whose fixed costs can't be covered, which is why for example condensing power plants are facing severe shutdowns in Germany.

Capacity mechanisms, Smart Grids and active end users can be seen as alternative methods to tackle the development needs in electricity markets. As concluded in Koreneff et al. (2014), these methods do not have to exclude each other but can complement each other and even be intertwined. Modern capacity mechanisms can deploy demand response and other Smart Grid features. Thus, a proper goal for electricity market development should be the selection of an efficient mixture of measures to ensure long-term generation adequacy and flexibility. Naturally, local circumstances have to be taken into account in this task.

4. European electricity market

4.1 High-level EU targets towards 2020, 2030 and 2050: CO_2 reduction, RES, Energy efficiency

The EU has introduced so called 20-20-20-10 goals for the year 2020, that have a great effect on the development of the energy and electricity sector in its 28 member countries. The EU’s binding targets for 2020 can be seen below.

- Greenhouse gas emission reduction 20 % by 2020 compared to year 1990
- Energy end use reduction 20 %
- Share of renewable energy form final energy use 20 %
- Renewable energy in transport 10 %

- Each EU country has its own target levels (share of renewables and GHG reduction target[7]) and different mechanisms for implementing the goals are used, and they have different impact on different parts of energy sectors.

EU leaders agreed on the domestic 2030 greenhouse gas reduction target of at least 40% compared to 1990 in October 2014 (see Table 3). The 2030 policy framework also sets a target of at least 27% for renewable energy and energy savings by 2030.

In 2011, the EU adopted the Energy Roadmap 2050 (EC 2011), where it states the target of reducing greenhouse gas emissions to 80-95% below 1990 levels by 2050. In the roadmap, the EC studies the challenges posed by EU's decarbonisation objective while at the same time ensuring security of energy supply and competitiveness. The Roadmap has also affected national long-term strategy processes.

[7] The GHG emissions included in the EU’s emissions trading system (EU ETS) have an EU-level cap. National GHG reduction targets have been set for those emissions, which are not included in the EU ETS.

Table 3. Key figures of the 2030 energy and climate framework of the European Union agreed in 2014.

<table>
<tr><th></th><th colspan="2">Greehouse gas emissions</th><th>Renewable energy</th><th>Energy efficiency</th></tr>
<tr><td rowspan="2">2020</td><td colspan="2">-20% (compared to 1990)</td><td rowspan="2">20% share of final energy use</td><td rowspan="2">-20% compared to baseline i.e. reduction of primary energy use to 17 247 TWh/year</td></tr>
<tr><td>Emission Trading Scheme (ETS) sector:

-21% (compared to year 2005), decrease of 37 Mt/year until 2020</td><td>Other sectors

-10% (compared to year 2005), divided between Member States</td></tr>
<tr><td rowspan="2">2030</td><td colspan="2">-40% (compared to 1990)</td><td rowspan="2">27% share of final energy use</td><td rowspan="2">No target, to be assessed together with reassessment of energy efficiency directive</td></tr>
<tr><td>Emission Trading Scheme (ETS) sector:

-43% (compared to 2005), decrease of 47 Mt/year from 2021 onwards</td><td>Other sectors -10% (compared to year 2005), divided between Member States</td></tr>
</table>

4.2 Directives for emissions from combustion plants

An industrial emissions directive (IED 2010) for large combustion plants, >50 MW_{boiler}, is already in force, restricting SO_2, NOx and particulate emissions from 2016 onward.

In December 2013 European Commission released a clean air policy package. A part of the package is a proposal for new Directive to control SO_2, NOx and particulate emissions from medium-sized, between 1 MW and 50 MW, combustion installations (MCP-directive). The MCP is planned to be in force 2025 for new plants and 2030 for old plants

The planned MCP directive's restrictions for particulates will increase the costs for solid fuels, especially biomass, and the levels might even be difficult to achieve, as scrubbers with heat recovery (the economic solution) will not suffice, and solid fuel plants would thus become costlier and less competitive (Pirhonen 2014). Plants operating less than 500 hours per year have it a bit easier.

4.3 Small and micro-scale end-user installations

Should end-user micro-scale installations be included in potential market (as opposed to reserve or auxiliary) capacity mechanisms? It is good to note that end-users dwell in a totally different market environment than the wholesale power market. End-users have to take into account network costs and end-user taxes and possibly even VAT. The “grid parity” of an end-user is thus very different that of a large producer. If we leave large industrial boilers out, end-user installations are not part of EU ETS either.

Usually small scale installations are, per se, more expensive than large scale installations. This is true for PV, for example. The benefits from supporting small scale installations can come from them having different grid parity and thus, possibly, needing less costly incitements.

Support additions not in line with the general rules of the market, on the other hand, can have quite ill effects. Extensive feed-in tariffs, where the producers have no balancing responsibilities, overburden other market participants or the system as a whole. One of the strength of an energy-only market is its simplicity. The more participants are outside the market and acting under a different set of rule, the worse the market itself will work. Net metering is another example of this. Net metering adds cost burdens that are difficult to forecast on others to pay for while, at the same time, removes one of the most cost-efficient sources of flexibility, the active prosumer, from the market.

4.4 What targets will rule?

Nuclear power has low lifetime carbon emissions. With the EU greenhouse gas target coming into force, a lot European, mostly Eastern, countries started to look at nuclear as the solution. This didn’t fare well in all EU circles and for that reason, one could assume, specific and competitive renewable energy and energy efficiency targets were set. However, these targets, together with the recession and the shale gas boom in the USA, have driven down the CO_2 market price and for instance led to coal replacing gas in power production.

The EU is at crossroads: will it let the markets rule and achieve the most cost competitive solution to greenhouse gas mitigation, or will it continue on the path containing increasingly elements of planned economy? Germany, as one of the driving forces behind the development with its extensive feed-in tariffs and forced nuclear shut-down, has had to reconsider its solutions. The additional costs of the green path has risen to over 6 cents per kWh for the end-user and with more and more production forms demanding support, the overall costs can rise even further. Lessons learned from Germany show that good intentions together with a reduced system understanding lead to impressive, but very cost-inefficient solutions. It is good to remember that planned economies do not have a good track record.

Lessons learned, the EU is now planning to let the CO_2 price be the main determinator for the EU emission trading system (EU ETS) sectors. The RES target is to be a EU-level target and, let’s hope, mainly targeted at the non-EU ETS sectors such as transport, services and households. If the EU-level RES target is too high, it will also affect the EU ETS sectors. Too fast or too costly changes affect the competitiveness of European industries and they can backfire, as a loss of competitiveness can impact on our economic power. It is our economic power that allows us to turn at a good pace towards renewables and sustainability.

Sustainability, even though not being an unambiguous term, is one of the targets often referred to in European strategies. It can be debated if all renewable energy based solutions are sustainable, or sustainable for Europe. For example, it can be easily justified that to build a European society’s energy system on dead trees in Canada or sugar canes in Brazil does not present the most sustainable solution even if it would present a solution towards RES or low carbon society. These are restricted resources and they might thus not be the basis of a long term European solution. The European solution should rely on RES sources it can rely on even in the long run.

4.5 The role of market characteristics in the capacity question

4.5.1 Unified and common electricity market?

As part of the European Union energy policy, opening of electricity market to competition has been considered a direction efficiently supporting the policy goals. Open and integrated electricity markets are seen as essential in order to meet the challenges of competitiveness, sustainability, and security of supply. The electricity market liberalisation process in the EU has been progressing gradually since the late 1990s.

The state of market integration has an effect on the capacity question studied in this report. That is, if the European grid is operated and the generation and flexibility resources are used efficiently in the short-term, the need for national solutions may reduce. Also, provided the supply-demand balance is reflected in the prices, it has a potential to improve the efficiency of allocation of market-based investments.

The European Union’s political aim towards a single European electricity market calls for investments in the grid infrastructure as well as harmonisation in electricity trading procedures. Integration development is influenced by physical cross-border transmission capacity development and allocation methods. The electricity market design harmonisation will potentially have an impact on market procedures in individual countries.

With regard to a target of European-wide electricity market, a pan-European grid forms an integrated marketplace for electricity market participants. Even supergrids, integrating grids in Northern Africa and Europe, are envisaged is some visions. Market coupling and physical grid integration can be seen as dimensions in the process of integrating the European electricity markets and opening them up to competition. (Ruska & Similä 2011).

In the Communication “Making the internal energy market work” (EC 2012), the European Commission and set a clear deadline of 2014 for completion of the internal energy market. There have been recent steps on the on-going process of European market integration. For example, Price Coupling in North Western Europe went live on 4 February 2014. Here, the price coupling stretches from France to Finland and from Great Britain to German/Austria, covering the region of CWE, Great Britain, the Nordics and the Baltics. This project has been implemented in close cooperation with Exchanges and transmission system operators[8].

Investments needs in grid infrastructure are identified in ENTSO-E[9]’s Ten-Year Network Development Plan (TYNDP) 2014[10]. RES development is seen as the major driver for grid development until 2030. According to analysis, the generation fleet will experience a major shift by 2030, with the replacement of much of the existing capacities with new ones, most likely located differently and farther from load centres, and involving high RES development. Regarding interconnection capacity boost, the TYNDP 2014 pinpoints about 100 spots on the European grid where bottlenecks exist or may develop in the future if reinforcement solutions are not implemented. The most critical area of concern is the stronger market integration to mainland Europe of the four main "electric peninsulas" in Europe (The Baltic States, Spain with Portugal, Ireland with Great Britain, and Italy). Interconnection capacity must double on average throughout Europe by 2030.

[8] http://www.epexspot.com/en/market-coupling
[9] European Network of Transmission System Operators for Electricity
[10] https://www.entsoe.eu/major-projects/ten-year-network-development-plan/tyndp-2014/Pages/default.aspx

Smart Grids and technologies have their acknowledged role in the market integration process. According to the Communication (EC 2012): “In electricity, new technical rules such as on cross-border balancing markets and on liquid intra-day markets, should, in combination with smart grids, help improve system flexibility and the large-scale integration of electricity from renewable energy sources and participation of demand response resources alongside generation”.

4.5.2 The role of nuclear

Eastern Europe countries, for example Bulgaria, Romania, Hungary, Slovakia, Lithuania, Slovenia, and Poland are increasing or planning to increase their nuclear power capacity. Also Finland is increasing its nuclear capacity, and Britain is planning new nuclear power plants with Hinkley Point C already furthest on the way having governmental consent on the long-term (35 years) support scheme of a contract-for-difference of 92.50 £/MWh, including index clause.

On the other hand, Germany has shut down several reactors directly after Fukushima and is planning to close the rest by 2022. France is building new nuclear plants but at the same time has taken a political decision to decrease the nuclear share from 70% to 50%. Sweden has had a tendency of changing the target with each change of government; as it stands, nuclear power plants are allowed to be replaced with new units, but the new government appointed autumn 2014 has a grimmer look on nuclear.

As nuclear is a low-carbon mode of producing electricity, it will help keep the greenhouse gas emissions down. Nuclear power plants are also the most economical solution for Eastern Europe, as the construction costs are low resulting in low electricity production costs. The support level for Hinkley Point C has been and can be discussed as, for example, the consortium behind the 6th Finnish reactor, Fennovoima, guarantees a price ceiling of 50 €/MWh for the all-including production costs. That is less than half the Hinkley Point C strike price.

The role of nuclear is of greatest importance for the future power system. Will old units be closed down before their time or will they instead be given life extensions? As greenhouse gas mitigation becomes costlier and costlier, will nuclear experience a renaissance also in Western Europe? For example, new small scale units of 200 MW have been advocated as a solution for the future: they will be easier and faster to construct and their safety easier to manage.

4.5.3 The role of national RES support schemes

Not all markets are equal. What’s more, an influx of heavily supported RES-E capacity and production has different repercussions depending on the current constellation of the power system. Whereas more monopoly or oligopoly minded traditional systems still have vast capacities including large reserves, long-running energy-only power markets have less excess capacity left, especially regulating generation capacity.

National RES-E support schemes are based on a planned economy approach and are a disturbance to the power markets: the faster the changes, the larger the impact. Power plants have lifetimes of 20-50 years, so dramatic changes in very short times, e.g. the German PV and wind developments, leave no room for market based reactions, i.e. a phase-out after reached lifetime, for other production types. They face a threat of being left unused and with stranded costs.

Support schemes are understandable when it comes to new beneficial technology that needs a push to get the manufacturing etc. infrastructure up and running. With wind and PV forming the majority share of new capacity for some years already, it is good to ponder if not the wind and solar industries are developed and mature enough by now. In a Europe in economic distress, if the EU ETS is not enough, which is should be, cost effectiveness of the support schemes is of essence.

National support schemes have also repercussions in other markets. Here we can look at Germany once again: Germany draws on neighbouring countries' flexibility for balancing their intermittent RES-E production as well as helping out with their internal transmission bottlenecks. This is not to a disadvantage to all; for example a storage based hydro system can buy electricity at low costs from Germany and sell it back at a high price.

Sweden and Norway have a common green certificate market with the target to increase RES-E with 26.4 TWh by 2020 from the 2012 level. Green certificates are market based solution for the introduction of new RES-E, with remuneration depending on the RES-E production level and competition.

4.5.4 Advanced energy-only electricity markets, Finland and the Nordic market

Finland has been a competitive power market for several decades, with energy-intensive industry and municipalities as capacity owners and power producers, mainly through CHP. Even before the deregulation of the market in the 90's there were two parallel transmission networks, one operated by the state owned IVO and one by the industry owned TVO.

Capacity support in the early days of deregulation was very limited with tax benefits to electricity produced by a restricted class of renewable sources (small scale hydro, biomass, wind) as well as investment support to new technologies such as wind power. The investment support to wind power was on the level of 30% to 40%, which with the high costs of wind power at that time led to few investments.

With the EU 2020 targets, especially for RES-E, Finland found itself in a situation where a lot of RES-E capacity was warranted for and thereby the first feed-in tariffs or more precisely, contracts for difference, were instigated. The target for wind power production is 6 TWh by 2020. Further targets have also been expressed, e.g. 9 TWh wind by 2025. The increased use of biomass, which is one of Finland's main RES potentials, is also supported. The Finnish government puts a lot of emphasis on cost efficiency. There is not yet any separate and higher support scheme for offshore wind, although the first installations are able to receive an additional investment support. Small scale power units are excluded from the feed-in tariffs, as the management and verification costs are doomed to be too high.

For power system operation and security reasons, the Finnish system operator has a capacity reserve system for existing peak/reserve power plants. The ongoing period will end in summer 2015, and it includes two oil based peak power plants, Kristiina 1, 210 MW, and Vaskiluoto 3, 155 MW (Fingrid 2015). Without the extra support, it is most probable that the power plants would be shut down as the fixed costs overwhelm any sporadic incomes.

New capacity has been and is introduced both on a market basis (new nuclear, non-RES CHP), with small fuel based inducements (bio-CHP) or due to strong support schemes (wind power). On a Nordic level, new hydro, wind, nuclear (including refurbishments) and CHP increase the base load capacity at the same time as the increase in demand has stopped, although mostly due to the recession. Condensing power plants are more and more being driven out from the market by a lack of need, although the EU emission directive for large and medium-sized combustion plants will offer its assistance in the nearest years.

Will we need new intermediate or peak power plants in the future, especially as the nuclear power plants may phase out around 2030? If we do need them, would it be more economical to retain the old plants? The Nordic system is quite dependent on hydro power, so will me manage a dry hydrological year also in the future? Dry years have been managed by larger imports and increased coal power production, but without coal and gas condensing capacity left, is it doable also in the future? It might be, at least on a general level. However, as

Finland is a peripheral area of the market, behind several transmission bottlenecks, and already heavily dependent on Nordic imports, it is not so sure that Finland will be as successful as the other Nordic countries in battling high demands and low productions. The good thing, though, is that the energy-intensive industry is more and more self-sufficient, so that mainly small industries, services and households may have to fight with high prices and scarce electricity deliveries.

We'll have a closer look at the expected market (price) development in the Nordic countries and especially in Finland in Chapter 5.

4.5.5 Germany –a battle ground between large utilities and prosumers

Germany has had high end-user electricity prices, taxes included, well before the deregulation, see Figure 6, with prices over 50% higher than in Finland. The German utilities were profit-making area monopolies and the end-users were not happy.

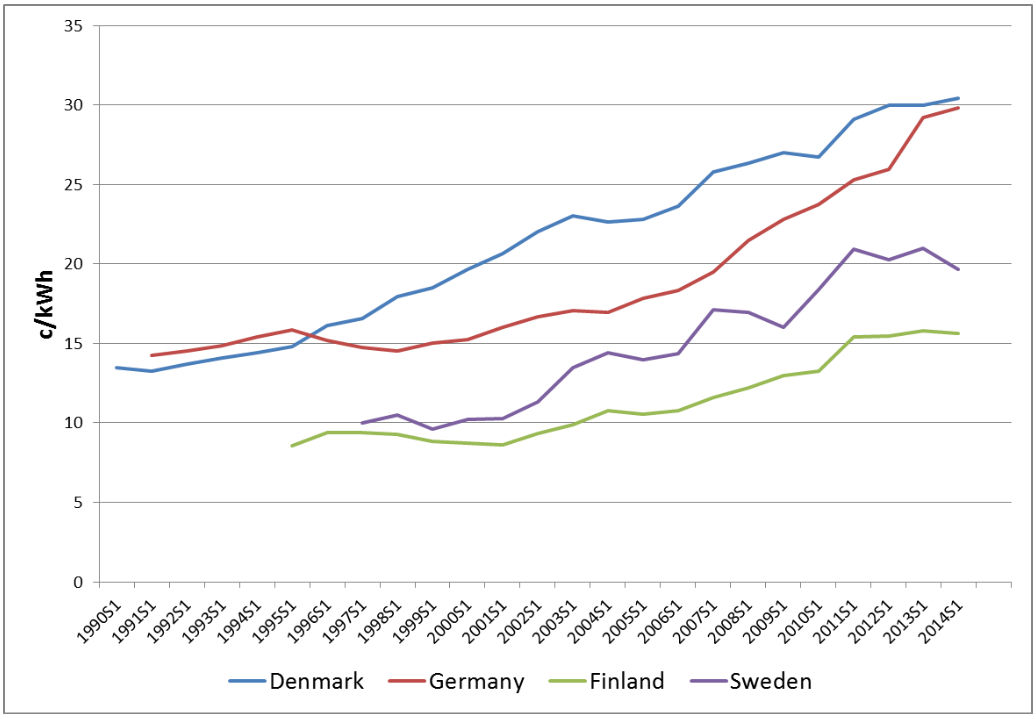

Figure 6. End-user (3500 kWh pre-2008 and 2500-5000 kWh after) average electricity prices in Denmark, Germany, Finland and Sweden. Data source: Eurostats 2015.

The monopoly utilities fought hard against the market deregulation and an open market, which resulted in a loss of goodwill from the public and the politicians. The German feed-in tariffs are "hard" on the utilities: they have to take the electricity produced and pay for it the feed-in price, and then themselves manage the marketing and the imbalances. The Nordic solution is different, here the RES-E producers have to market the electricity with all the trading and imbalance costs that includes.

The wind and especially the PV investments are in Germany made by end-users or small consortiums. Villages want to be self-sufficient, micro-grids are booming, and distributed generation, independent of its costs, is favoured and supported. The case of Germany is very interesting with both a steep increase in PV and wind capacity in recent years, Figure 7, at the same time as new coal and gas condensing power is being introduced to the market.

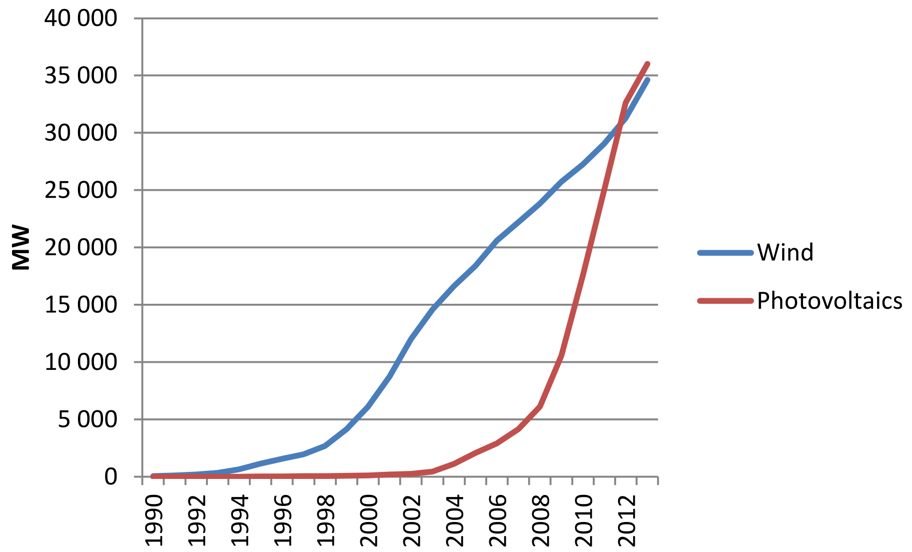

Figure 7. Capacity of wind and photovoltaic power in Germany, 1990-2013. Data source: Eurostat, preliminary Eur'observer data for 2013.

Traditional energy utilities such as E.ON, RWE and EnBW are shutting down conventional power plants and even making losses (MPS 2014). Much needed new transmission capacity between the North and the South is not being built at the same time because of complaints, and end-user prices are exorbitant. One of the reasons for this shamble is the very rewarding feed-in tariffs for wind and PVs, bringing a lot of capacity online in just a few years. On sunny days during the summer half-year PV forms quite a huge chunk of the total power demanded, driving condensing power plants out. This leads to lower capacity factors for condensing power plants, which hurts their profitability, which the reduction in nuclear capacity hasn't helped out enough. Fossil condensing power plants need, or at least want, capacity mechanisms to stay in business.

5. The Nordic and Finnish market 2035

5.1 The Nordic market development up to now

The Nordic electricity market development is more thoroughly presented in SGEM-report Koreneff et al. (2014). Here we only give a quick review of the demand and supply.

The Danish, Swedish and Norwegian electricity demands have been on a quite stable level for some time, see for example Figure 8, allowing of course for fluctuations from year to year. The Nordic demand was lower in 2011 than in 2002. The demand is, however, affected by the global economic recession started in 2008. The Nordic demand is also quite receptive to both the temperature and the hydrological year. The stable demands might be expected to stay more or less stable, despite that energy efficiency measures are stepped up, as the measures are expected to lead to an increased electrification of energy use and thus counterbalance the savings reached in electricity use.

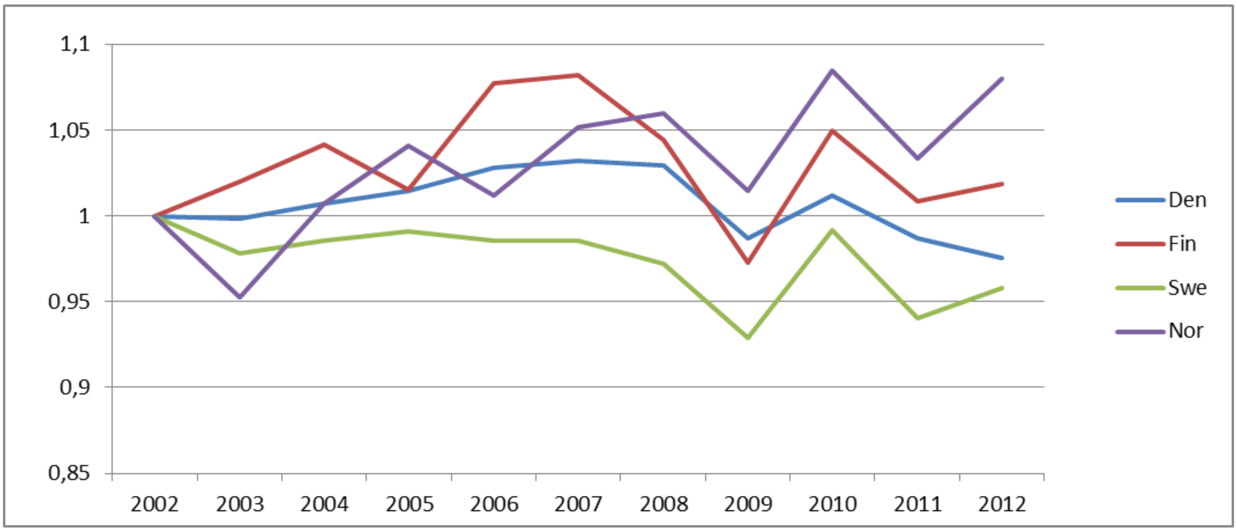

Figure 8. Relative net electricity demand 2002-2012 in the four Nordic countries, 2002 = 1. (Source: Koreneff at al. 2014)

There is a large amount of new non-fossil capacity coming to the Nordic market. The Swedish-Norwegian green certificate system has a target of 26.4 TWh of new RES-E production from 2012 to 2020. Denmark has set the target of getting half the electricity from wind power in 2020 and the wind power target for Finland is 9 TWh in 2025. New nuclear power is being built in Finland and old plants in Sweden are being refurbished, with raised capacities as a result.

At the same time, conventional older gas and coal power plants are being retired not only because of their age, but because they are unprofitable to uphold in the long run. The EU environmental directives for SO_2, NOx and particular emissions are also forcing older plants to either costly refurbishments or early retirement.

5.2 The development of the Finnish market up to now

From the beginning of the age of electricity markets (1995), new capacity investments have in Finland concentrated on CHP (industrial and urban) and nuclear. Both of these can be classified as base load generation. Disinvestments have focussed on conventional coal condensing plants. Wind power is gradually getting momentum and it will reach near to 10% share of electricity supply at 2025. Electricity procurement in Finland 1990-2013 is shown in Figure 9. District heat CHP grew from the 90’s to the 00’s, but so did nuclear (through plant refurbishments) and net imports.

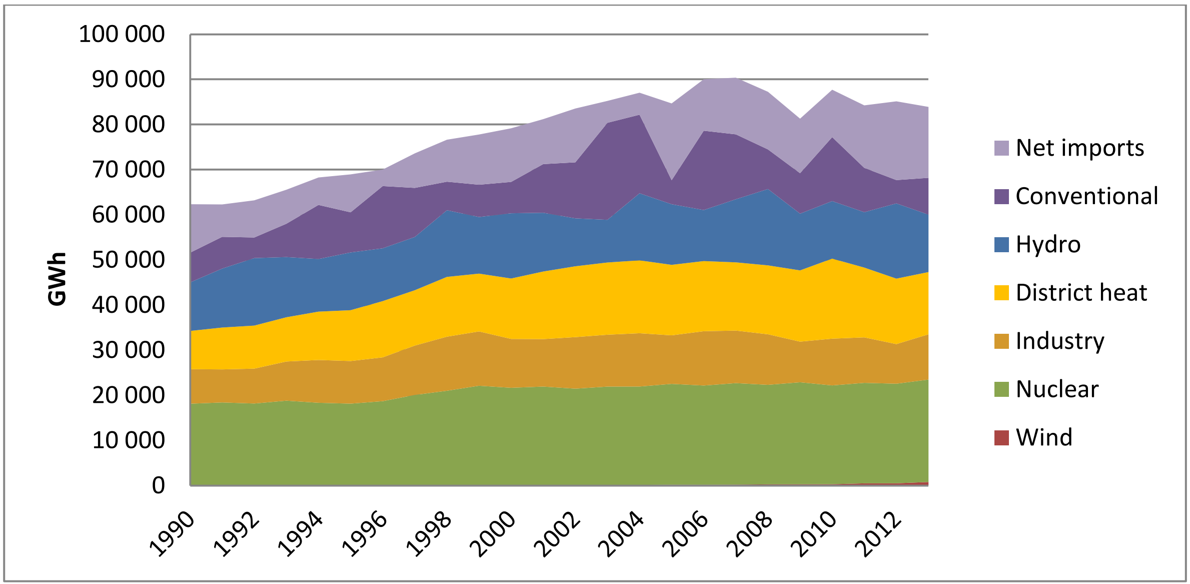

Figure 9. Electricity procurement in Finland 1990-2013. Source: Statistics Finland.

The amount of imports is on average higher after the market reform than before it. The amounts imported and generated by conventional condensing are volatile reflecting the market price changes. There is a radical change in the structure of the imports at 2012, see Figure 10.

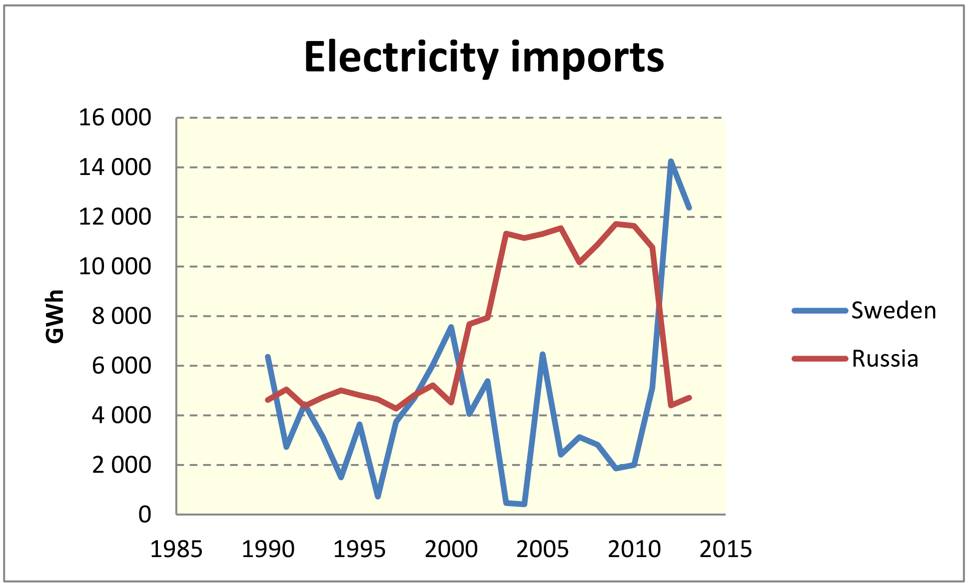

Figure 10. Import structure. Source: Statistics Finland.

The structure of imports changed end 2011 due to changes in export conditions in Russia: the exporter has to pay a capacity fee that made exporting uneconomic. Since then imports from the west have dominated but at the time of writing, the exchange rate between rouble and euro has changed so that imports from Russia are growing.

The capacities of different generation classes have developed as shown in Figure 11 and the development of condensing power is shown in more detail, including production and full load hours, in Figure 12.

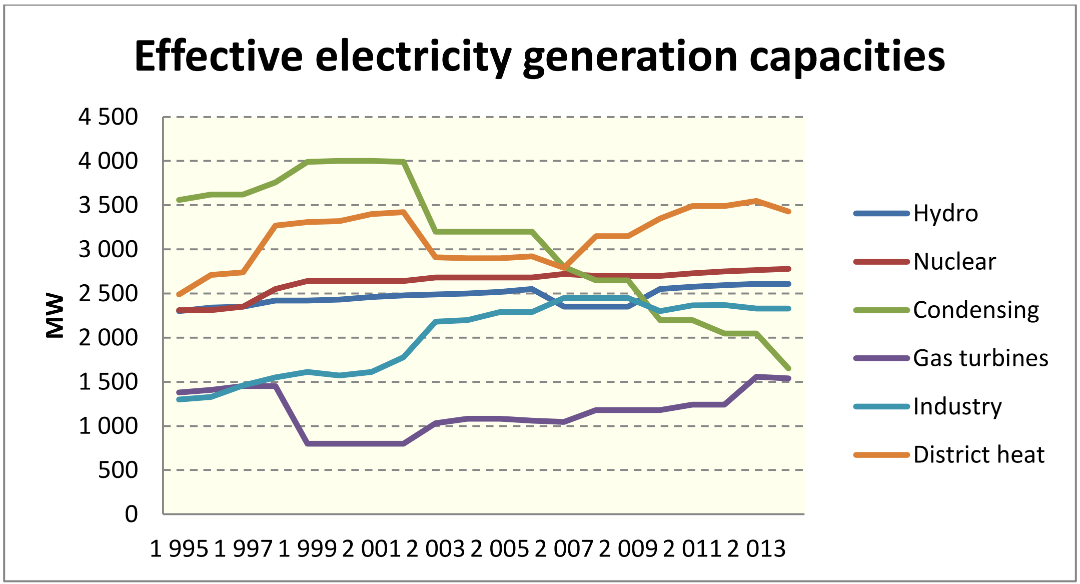

Figure 11. Generation capacities from the beginning of the electricity market era. Source: Statistics Finland.

During the first decade of electricity markets, from 1995 to 2003, the condensing capacity stayed for the most of the time idle reflecting the deregulated imports regime. After that the capacity abandonment began. Figure 11 shows interesting trends: i) Condensing capacity is diminishing – an abandonment process is going on; ii) Combined heat and power production growth has saturated both in industry and in cities; iii) system reserves are growing gradually. Gas turbines are considered as system reserves, not as generation capacity.

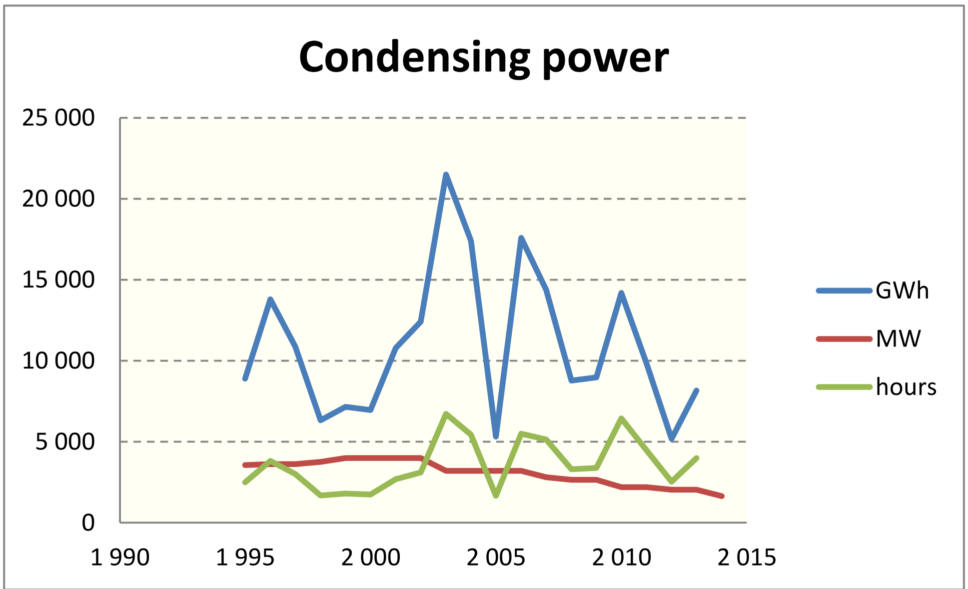

Figure 12. Condensing power: generation (GWh), capacity (MW), and full load hours. Source: Statistics Finland.

By cutting down the capacity, condensing power generators have succeeded in keeping the full load hours on a reasonable level, slightly less than 5000 hours/year, see Figure 12. One reason not visible in the capacity development is the ongoing construction work of a new 1600 MW nuclear power plant that is expected to be commissioned at 2018. It will take market share from the imports and condensing generation from there on.

With the coming nuclear capacity, the wind power support programs in place and existing hydro power capacity, there seems to be no need to make any market-based investments in intermediate or peak capacity. Available import capacity is nowadays about 3500 MW that complements the existing generation capacity. Decommissioning of the existing four nuclear reactors in Finland takes less than a decade and it will start at 2028. It is almost a step-wise capacity reduction of 2700 MW, corresponding to 20 % of overall capacity. It will be interesting to see what kind of plants, if any, will replace them.

Heat demand that has to be met somehow forms the basis for a CHP project. Without heat load it would be a condensing plant project. The synergy of heat and electricity production gives it a cost advantage that explains the investments from the beginning of the electricity market era. Nuclear plants are a special case in many dimensions. The existing ones have been an economic success but there are doubts on the economics of the coming ones with steeply rising investment costs.

At present, investments in new import channels form an alternative to an investment in generation. The option of enlarging the import capability can efficiently prevent any condensing investments to take place.

5.3 District heating –effect on the power market

District heating is closely connected to the power system in the Nordic countries. District heating forms the major heat source for households and the service sector (shops, offices, schools, hospitals, hotels etc.) in Denmark, Sweden and Finland. In Denmark and Finland, around three quarters of DH is from CHP. If we add industrial CHP, the CHP share of electricity production is around 10% in Sweden, 35% in Finland and 50% in Denmark (Eurostat 2014).

DH is not expected to increase much as energy efficiency measures in old houses and strict building codes for new houses are expected to affect the heat demand stronger than the increase in floor area. According to recent research (Koreneff et al. 2015), the Nordic district heat demand is expected to decrease in the future but still remain a strong competitor. Figure 13 shows how the division (bioenergy, oil and gas, district heat, electricity and other) of the final energy for heating is estimated to develop in the Nordic countries from 2010 to 2050 according to TIMES-VTT[11] model results.

Existing DH networks and demands are also experiencing a tough competition from end-user heat pumps. The price of district heating has risen in recent years mainly because of higher fuel taxes. End-user energy unit based electricity tariff components (i.e. c/kWh) in Finland are for example 13 cents per kWh, which with a heat pump with a coefficient of performance of over 3 gives variable heat costs of around 40 €/MWh resulting in a sizeable saving compared to the energy based price components of DH companies, which are 70 €/MWh on average (ET 2015) but might be even over 100 €/MWh.

TIMES-VTT model estimations show that district heat CHP in the Nordic countries will decrease by 30% to 2020 and by 38% to 2030. Where the TIMES-VTT results for district heating CHP in Finland is showing a clear downward trend, the background report to the national energy and climate strategy (TEM 2013) shows a more modest reduction, 0.6 TWh by 2020 and 1.4 TWh by 2030. SKM Market predictor (2012) estimates that Finnish DH CHP will retain its competitiveness and remain stable up to 2035. (Koreneff et al. 2014)

[11] The TIMES-VTT is a partial equilibrium model of the global energy system based on linear optimization. It is based on the TIMES energy system modelling framework developed under the IEA Energy Technology Systems Analysis Programme (ETSAP) and the global ETSAP-TIAM model (Loulou et al. 2005, Loulou & Labriet 2007).

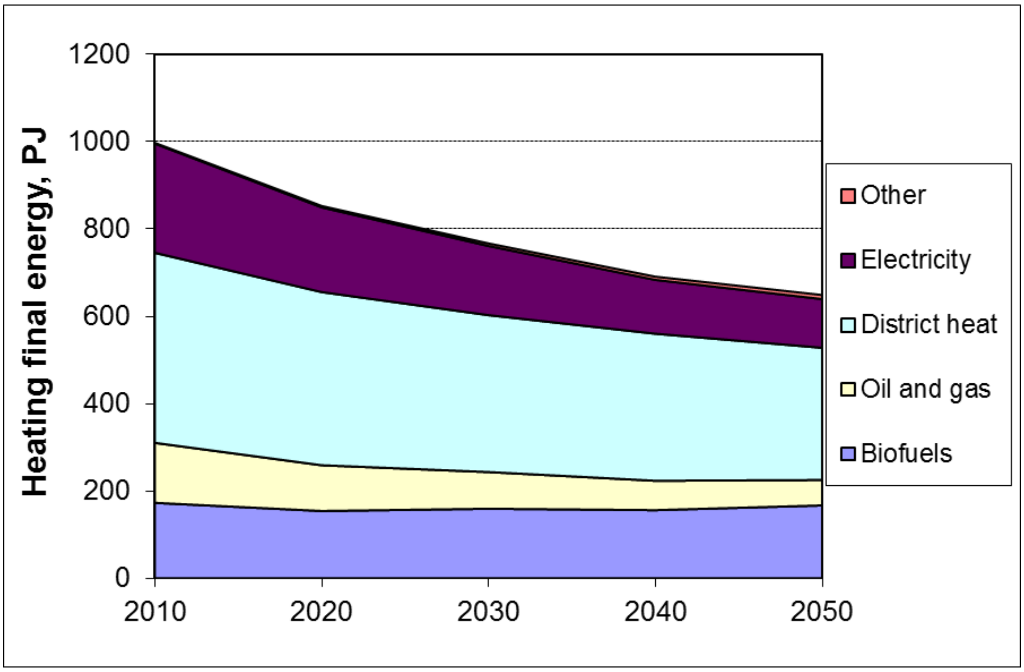

Figure 13. Estimated heating development in the Nordic countries 2010-2050 according to TIMES-VTT. (Koreneff et al. 2015)

The DH system offers tremendous opportunities for reasonable priced flexibility:

- First of all, large electric boilers such as were in common use in the 80's. The boilers are inexpensive, for example 20-40% cheaper than gas boilers (Energistyrelsen 2014). During times of surplus and thus inexpensive electricity, for example on windy days in the future, power can be turned to heat and it is thus replacing fuel based heat production, a win-win situation.

- CHP production can be reduced at times of surplus electricity and the heat produced with boilers, preferably electric ones, instead.

- Heat storage are several decades cheaper than batteries or even pumped hydro storages. Even the DH networks can be used as short term storages. Storages offer up and down regulation together with CHP power plants and electric boilers. If the heat demand is lower than the CHP capacity but electricity production would be valuable, the CHP plant can run at maximum and the produced heat can be stored. CHP production can be decreased and heat storage used instead, if we have excess electricity. We can also use the electric boiler to load the heat storage.

- DH heat pumps are more expensive than electric boilers, but give a lot more heat for each unit of electricity used. Heat pumps can also be used with thermal storages.

Taking the above into consideration, one could ask should there be policies in place to take care of not letting the DH load disappear by “accident”, but at the same time not force DH in uneconomical cases, i.e.:

- Are fuel taxes in district heat production correctly dimensioned?

- Should district heat tariffs be more fixed or power/ flow rate oriented to get rid of air heat pumps?

- Are expensive district heat networks are better solution than individual ground source etc. heat pumps or are they obsolete? End-user electric heating, including heat pumps, forms a recognisable source of flexibility itself.

- Should there be some incentives in advancing district heating, or at least not letting heat load erode by partial optimising agents?

- Would new detached low-energy house areas best be served by other means than district heating, and let district heating focus on what it is best at: producing heat for high heat demand density areas?

Other Nordic countries have also their own problems. Sweden has a lot of must-run heat production, i.e. heat from waste as waste cannot be stored for long times at the plants. As people are installing alternative heat sources, e.g. air-water heat pumps or solar heating, in district heating houses, the heat demands are reduced, even more so in the summer, leaving waste heat to be wasted. One solution offered is to have seasonal DH energy prices with low summer prices and high winter prices. This, on the other hand, would be a greater incitement for air-air heat pumps mainly used during the heating season.

Denmark, for example, is a forerunner when it comes to small scale DH solutions with solar heating, CHP, seasonal heat storages and even deep geothermal heat. As Denmark has a lot of wind power, the flexibility of the DH system is already put to use to some extent.

Norwegian DH is quite rudimentary compared to the other Nordic countries and it takes place in mainly small area networks. Norwegian city houses are to a large degree directly heated with electricity, which means that conversion to district heating would need a lot of expensive plumbing to be done in the houses. District heating is, however, increasing and especially new construction sites are a potential.

5.4 The market case studies setup

We study here the Nordic countries in the Nord Pool market, i.e. the Swedish, Danish, Norwegian and Finnish areas. In addition, using the input from the Nordic cases, we look separately at what happens in the Finnish price area. The timeframe is from today to 2035. The price scenarios are done using VTT's Electricity market model, VTT-EMM (Tamminen et al. 2014).

We assume a Nordic capacity as presented in Figure 14. New RES-E capacity is expected to develop according to national strategies and targets, for example the Swedish and Norwegian green certificate target of 26 TWh new RES-E by 2020, and Finland will have 6 TWh of wind power in 2020 and 9 TWh in 2025. Hydro will increase to any noteworthy extent only in Norway, whereas wind will increase in all four countries. All simulations are run as normal, i.e. average, hydrological years.

The demand is expected to increase, but slowly, see Table 4. The demand expectations follow the guidelines given in Koreneff et al. (2014) with a very small decrease, -1 TWh, to the Finnish estimate for 2020 as a reaction to recent economic and energy data.

Table 4. Nordic demand estimates as used in the SGEM calculations in this report.

Demand TWh	**2015**	**2020**	**2025**	**2030**	**2035**
Finland	86	92	96	99	102
Sweden	144	147	149	150	150
Denmark	36	36	37	37	37
Norway	126	126	128	129	130
SUM Nordic	**392**	**401**	**410**	**415**	**419**

There will be more new power production than what the expected demand increase during the next ten years. This will give some leeway for further ponderings on capacity mechanisms, assuming that production from existing capacity is not severely hampered by shut-downs.

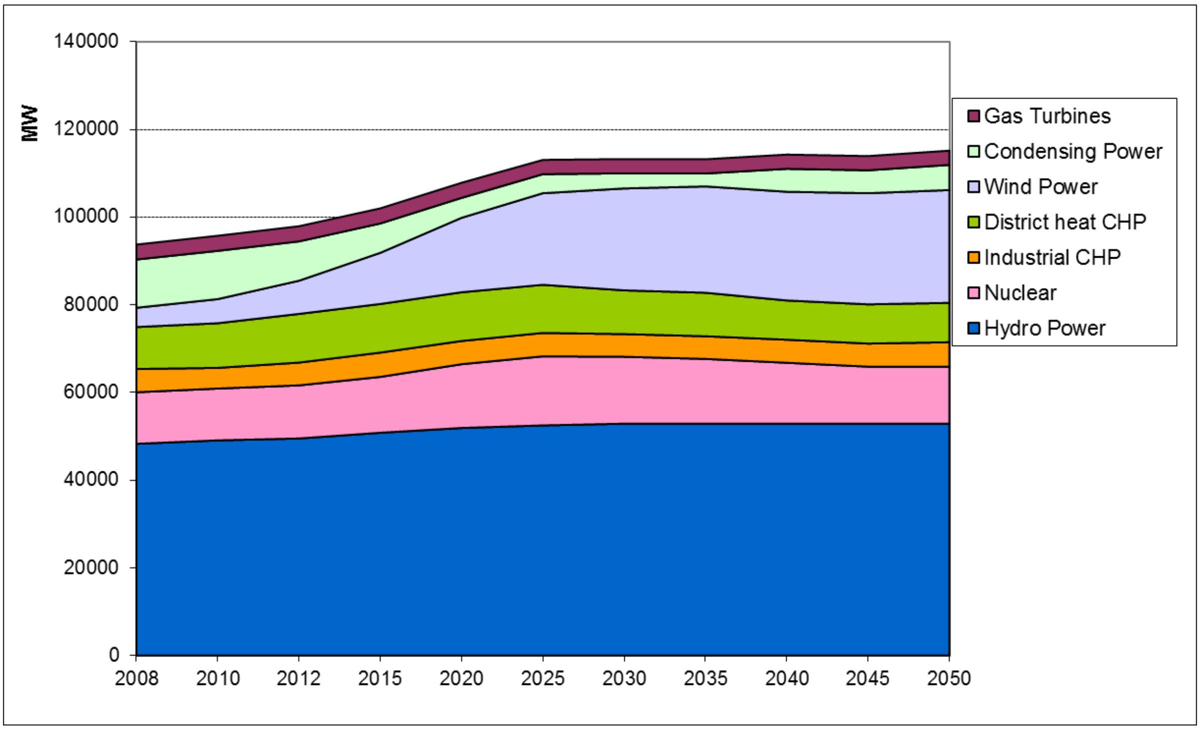

Figure 14. Assumed Nordic capacity development 2008-2050 in the VTT-EMM model.

As the development of the Swedish nuclear capacity is of importance for the market, we look at three scenarios beside the reference scenario ("Base"), where the nuclear capacity is expected to remain stable (lifetime extension or potential outgoing units replaced by new equivalent units). The reference case and the three Swedish nuclear scenarios are:

- *Base:* the capacity of nuclear power in Sweden remains at its current level.
- *High:* nuclear units are decommissioned after 50 years of service and replaced by new 1200 MW units
- *Mid:* nuclear units are decommissioned after 50 years of service and partially replaced: one 1200 MW unit before 2030 and two 1200 MW units before 2035
- *Low:* nuclear units are decommissioned after 50 years of service and no new nuclear power plants are installed in Sweden.

The four development scenarios of Swedish nuclear capacity, in accordance to the guidelines above, are presented in Figure 15.

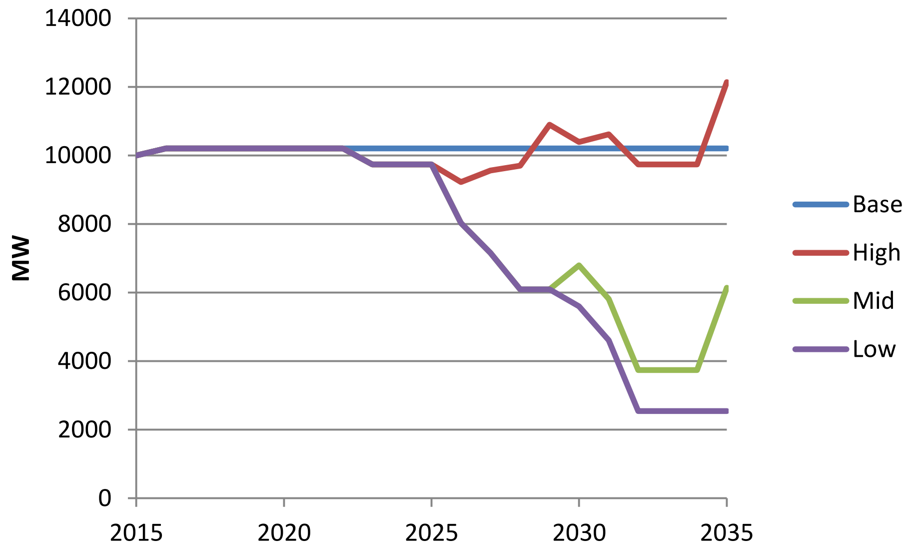

Figure 15. Assumed nuclear power capacity in Sweden in the four studied scenarios.

In addition, we also look at three different EU ETS and fuel price scenarios in addition to the reference scenario ("Base") that is based on the IEA New policy scenario (IEA WEO 2014):

- *Base:* IEA New Policies scenario
- *450*: IEA 450 scenario, where the target is to keep the global temperature rise below 2 °C which means a maximum of 450 ppm CO2 eq. concentration in the atmosphere.
- *Current:* IEA Current Policies scenario
- *Current, Null CO2*: As the Current Policies for other fuel prices, but with a breakdown of the EU ETS after 2020, i.e. a CO_2 price of 0 €/t_{CO2}.

The fuel and CO2 price developments are presented in Table 5.

Table 5. The fuel and CO2 price developments in the different IEA scenarios. Data source: IEA WEO 2014.

		2020	2030	2040
Natural gas €/MWh	IEA New Policies	31,6	34,4	36,1
	IEA Current Policies	32,7	37,5	39,8
	IEA 450	29,9	28,4	26,2
Oil €/MWh	IEA New Policies	53,1	58,3	62,5
	IEA Current Policies	55,0	65,9	73,4
	IEA 450	49,7	48,3	47,4
Coal €/MWh	IEA New Policies	10,7	11,4	11,9
	IEA Current Policies	11,3	12,4	13,1
	IEA 450	9,3	8,3	8,2
CO2 €/t	IEA New Policies	16,5	27,8	37,5
	IEA Current Policies	15,0	22,5	30,0
	IEA 450	16,5	75,0	105,0

5.5 The electricity market development to 2035

5.5.1 Swedish nuclear scenarios

5.5.1.1 The Nordic market price 2015-2035

Figure 16 presents the model results of the Nordic system price of electricity under different assumptions of Swedish nuclear capacity. Differences in nuclear capacity begin to reflect in electricity prices visibly in 2030. In 2035, the “High” scenario suggest an estimate of 53.30 €/MWh for system price, whereas for “Low” scenario, the estimated price is 65.75 €/MWh. Interestingly, there is a difference of over 12 €/MWh or over 20% in yearly average price in 2035 between the *High* and *Low* scenarios. The difference in capacity equals 9600 MW. As Nordic electricity demand is estimated to be 419 TWh in 2035, this would correspond to a difference of 5000 million euros. Using these figures, we obtain a value of 540 €/kW/year. From the Nordic electricity user’s perspective, the value of the Swedish nuclear power production is 72 €/MWh.

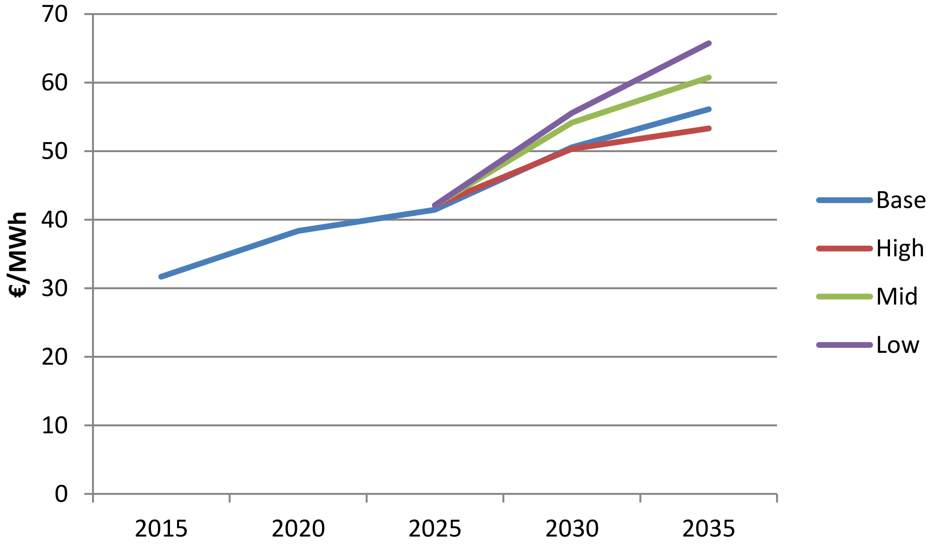

Figure 16. Market price of electricity (Nordic system price) according to model calculations under different nuclear capacity assumptions for Sweden.

In Figure 17, we study the annual export-import balance of Nordic electricity market area in the Swedish nuclear scenarios. It is clearly seen that in the low nuclear capacity scenario, the Nordic area turns into net importer in 2035. In scenarios with high nuclear capacity, the annual net exports exceed 40 TWh, correspondingly.

Figure 17. Net imports of the Nordic market area in selected scenarios according to model calculations. Negative values indicate net exports, i.e. the annual export amounts exceeding annual imports.

As profitability of condensing power plants is seen as a key question related to the need of capacity mechanisms, Figure 18 presents estimated condensing power production in the Nordic area for years 2030 and 2035. We notice that condensing power is in the range of 4 to 6 TWh in 2035, with smaller values in scenarios with high nuclear capacity. As the base case simulation gives an amount of 12 TWh of condensing power production in 2015, the results suggest condensing power in the Nordic is on a diminishing path towards 2035 compared to the situation today. This illustrates the capacity question: the position of condensing power seems to be threatened assuming the development of Nordic capacity as described. Even dry years would not have that a large impact except in the *Low* scenario as net exports would just decrease or maybe even turn to net imports. However, flexibility characteristics of condensing production abstracted away in the model used might justify at least part of the capacity staying in the market.

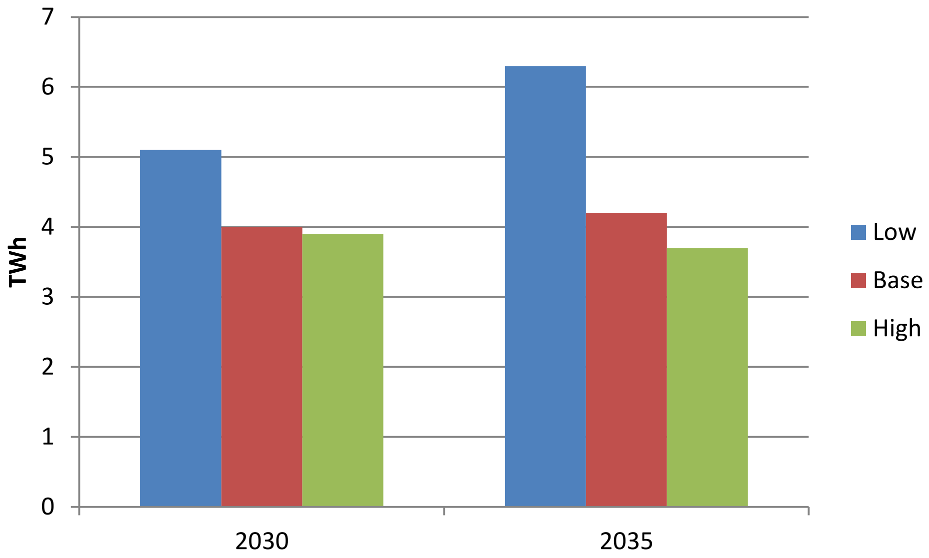

Figure 18. Condensing power production in the Nordic market area in selected scenarios according to model calculations.

5.5.1.2 The Finnish market price 2015-2035

Figure 19 presents the model results of the Finnish area price of electricity under different assumptions of Swedish nuclear capacity. Comparing with the system price estimations (Figure 16), we observe that the Finnish area price corresponds quite well to the Nordic system price. The most significant variation is to be found in the “High” scenario. That is, in 2035 the Finnish area price, 54.78 €/MWh is some 3% higher than the system price, 53.30 €/MWh, if we have a lot of nuclear power in Sweden. This indicates transmission bottlenecks between Finland and Sweden hindering a flow of cheaper electricity to Finland and causing the Finnish area price to rise. Finnish imports in the different model runs confirm this. The price differences in the other scenarios are small in comparison.

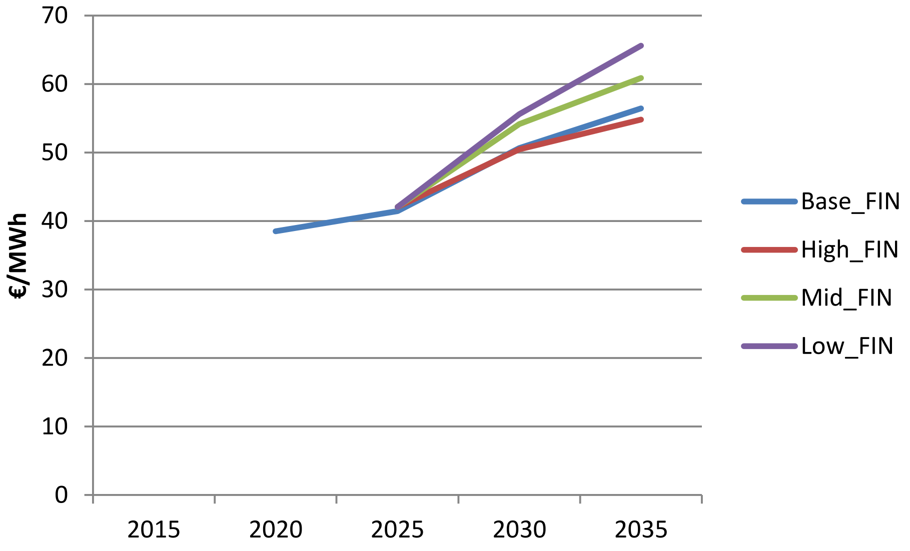

Figure 19. Estimates for Finnish area price of electricity according to model calculations under different nuclear capacity assumptions for Sweden.

5.5.2 Fuel price and EU ETS scenarios

We also study the effect of fuel and CO_2 price developments on Nordic and Finnish electricity prices. Figure 20 presents the information of Table 5 to illustrate the major differences in fuel and CO_2 prices between the IEA World Energy Outlook scenarios. That is, we see the 450 scenario presenting very high CO_2 prices (dashed lines) in comparison to New Policies and Current Policies scenarios. Contrary to that, the rise of fuel prices is higher in New Policies and Current Policies in comparison to the 450 scenario, where a decreasing development for of fossil fuel prices is assumed.

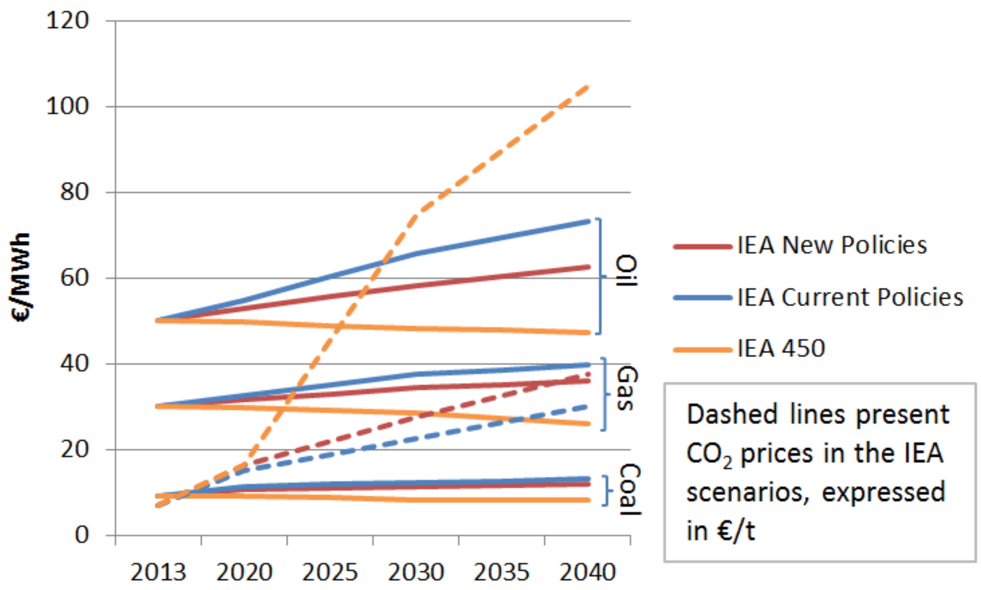

Figure 20. Assumptions of fuel and CO_2 price developments in the IEA scenarios. Dashed lines present CO_2 prices in the IEA scenarios, expressed in €/t

5.5.2.1 The Nordic market price 2015-2035

Figure 21 demonstrates the estimated system prices in the Nordic electricity market under different assumptions of fuel and CO_2 prices. We observe the CO_2 price having a large impact on the electricity price. That is, the 450 scenario with the CO_2 price approaching a level of 100 €/t towards the end of the time horizon shows the highest electricity price by a clear margin. On the contrary, the Current policy scenario does not differ significantly from the Base scenario.

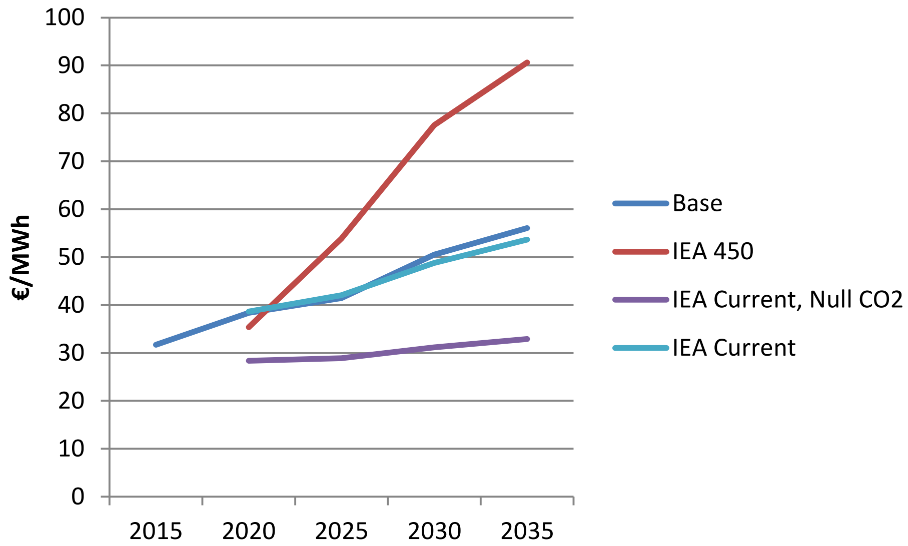

Figure 21. Market price of electricity (Nordic system price) according to model calculations under different fuel and CO_2 price assumptions.

5.5.2.2 The Finnish market price 2015-2035

Figure 22 presents the model results of the Finnish area price of electricity under different assumptions of fuel and CO_2 prices. Qualitatively, the Finnish area prices appear to behave similarly as the Nordic system prices. That is, only small differences between simulated Nordic system price and Finnish area price are revealed in the figures, indicating transmission capacity between countries being sufficient enough to keep the prices unified.

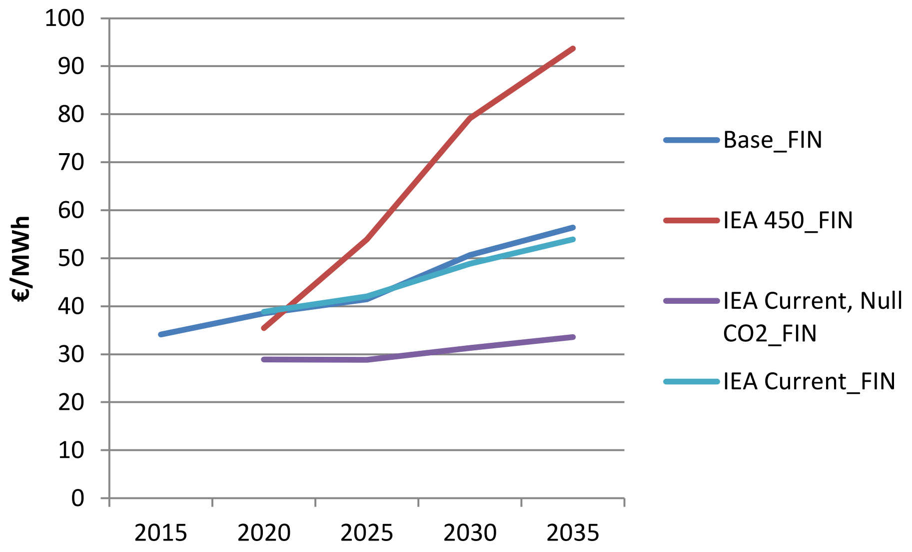

Figure 22. Estimates for Finnish area price of electricity according to model calculations under different fuel and CO_2 price assumptions.

Table 6 presents the differences numerically in order to study the differences more closely. In the Base and IEA Current scenarios, the simulated annual mean price difference is below 1% for all the simulated years. In the “IEA Current, Null CO_2” scenario, the difference reaches at most 2%.

Table 6. The difference between Finnish area price and Nordic system price, €/MWh. Positive value indicates the Finnish area price being higher than the Nordic system price.

	2020	2025	2030	2035
Base	0.15	-0.02	0.10	0.34
IEA 450	0.07	0.13	1.64	3.07
IEA Current, Null CO2	0.57	-0.06	0.11	0.67
IEA Current	0.16	-0.01	0.05	0.32

We observe the biggest difference in comparisons to Nordic system price in the IEA 450 scenario. That is, the electricity price in the Finnish market area in the 450 scenario rises steeper than in the Nordic system price estimations. The price reaches a level of nearly 94 €/MWh in 2035, whereas the corresponding Nordic system price is below 91 €/MWh.

Why do the results of the Nordic and Finnish simulations show a difference in the 450 scenario in 2035? A closer investigation reveals a difference in condensing power production. According to the results, in the Nordic simulation, condensing power production in Finland is 6 TWh, whereas in the Finnish market simulation, the corresponding volume is 8 TWh. Also, in the Finnish area simulation, Finland has to rely more on its domestic electricity production, as net imports are annually 6 TWh lower than in the Nordic simulation. In the assumed circumstances for 2035, where CO_2 price is strikingly high, the electricity supply costs in Finland are hit more than in the Nordic area. Correspondingly, the results indicate that limitations in transmission capacity prohibit the flow of relatively cheap electricity to Finland, making its annual average area price higher than the system price.

6. Levelised production costs versus market price

The total production costs of electricity can be calculated as cost per output including investments and interest rates, fuel costs and fixed and variable operation and maintenance costs. The unit production cost can then be compared to market revenues to see if an investment is profitable or not or compared with other alternatives to find the best one.

6.1 Projected costs of generating electricity

One way to compare different electricity production technologies is by using the levelised costs of electricity per MWh (LCOE), where all costs and benefits are discounted or capitalised to the date of commissioning. LCOE depend heavily on underlying assumptions about, e.g. discount rates, fuel, CO_2 or construction costs, efficiencies, load factors and lifetime of plants. A more detailed methodology can be studied for instance in (IEA 2010).

6.1.1 IEA

The International Energy Agency, together with the Nuclear Energy Agency, projects the cost of generating electricity regularly. In the 2010 edition (IEA 2010), the costs are projected at a commissioning date at the end of 2015. The prices are in US dollars of 2008.

The carbon price assumed is 30 $/t_{CO2}$ in all OECD countries, and a price of 35 $/MWh for gas and 13 $/MWh for coal in Europe. Wind plants have an expected lifetime of 25 years, gas-fired power plants of 30 years and coal-fired power plants of 40 years. Gas and coal power plants are assumed to be base load plants with a load factor of 85%.

The LCOE (5% discount rate) for power plants in Germany, the market nearest to the Nordic countries, are presented in Figure 23. Coal Bk refers to black coal and Coal Br to brown coal. PCC stands for pulverised coal combustion and CC(S) for carbon capture.

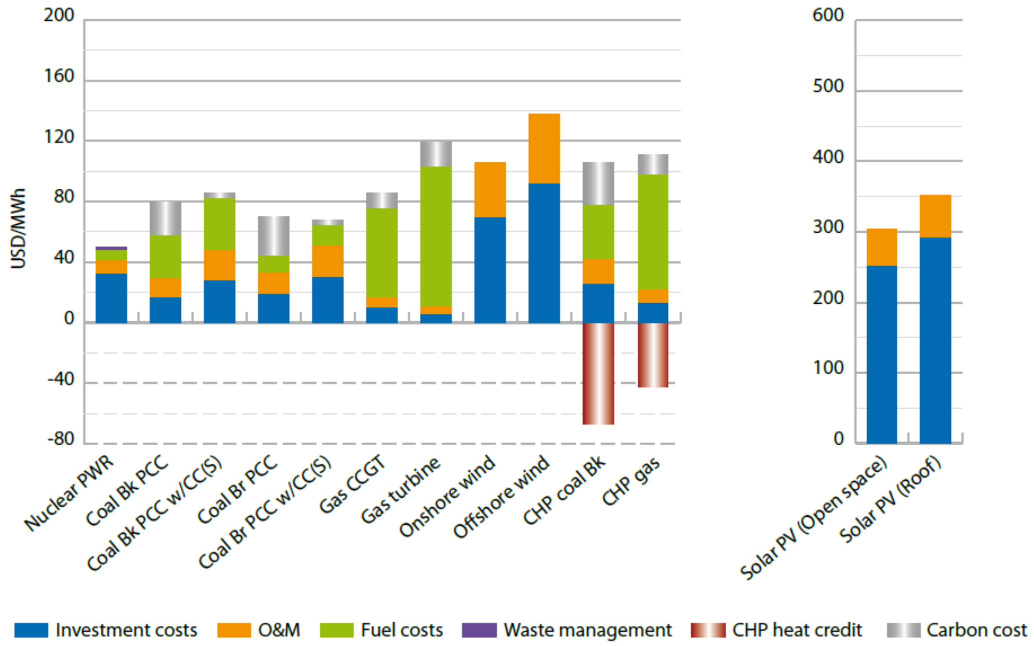

Figure 23. The levelised costs of electricity in Germany (at 5% discount rate). To be noted: the study was pre-Fukushima, cost of nuclear has gone up since then. Source: IEA 2010.

6.1.2 WEC

World energy council, together with Bloomberg New Energy Finance, (WEC 2013) gives an estimate of global LCOE of different, mainly RES, production forms. The compressed results are shown in Figure 24. The prices are in US dollars of 2012. For the LCOE they calculate with a nominal 10% return on investment for equity investors. The fuel costs were higher in 2012 than what they are today. The LCOE differs greatly between regions. For example, the LCOE range of base load coal condensing power is 35-39 \$/MWh in China, 77-79 \$/MWh in the USA, 93-126 \$/MWh in Australia and 119-172 \$/MWh in United Kingdom.

The LCOE of WEC are useful as a global reference and to show the large cost variety for a given technology, but many of the assumptions and the cases are not Nordic. The price estimates cannot directly be used as a reference level for the Nordic or the Finnish markets.

The LCOE average scenario range for onshore wind is 79-83 \$/MWh in Sweden, 80-85 \$/MWh in Denmark and 79-82 \$/MWh in Germany. The LCOE average scenario range for base load biomass (here agriculture residues, energy crops, forestry residues and wood pellets) incineration in Western Europe is estimated to be 50-200 \$/MWh, much depending on the biomass feedstock supply chain cost.

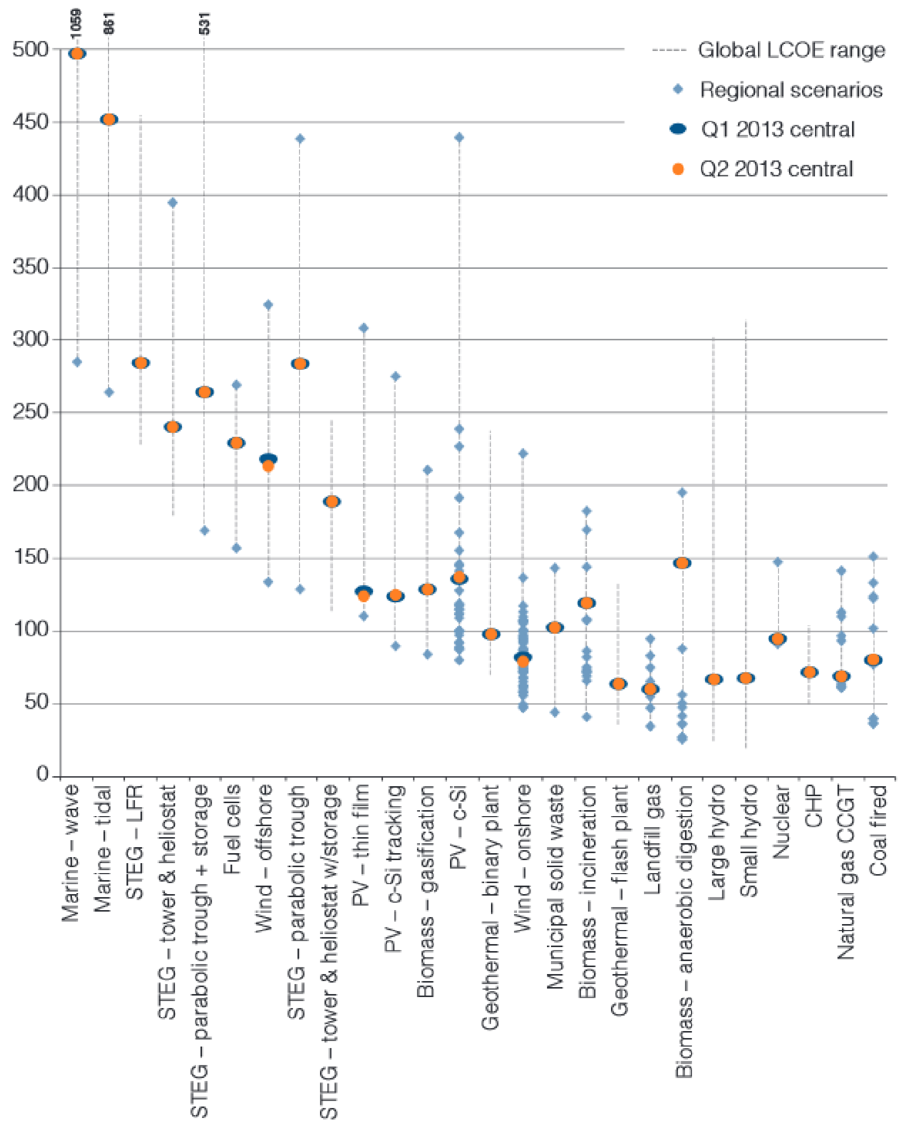

Figure 24. Global levelised cost of energy in Q2 2013 (USD_{2012}/MWh) according to Bloomberg New Energy Finance. Source: WEC 2013

6.1.3 International Renewable Energy Agency IRENA

The International Renewable Energy Agency (IRENA 2015) is especially estimating the renewable power generation costs. The levelised costs of electricity from renewable technologies as regional averages are presented in Figure 25. As can be seen, the European cost level is very high compared to other regions for almost all technology types.

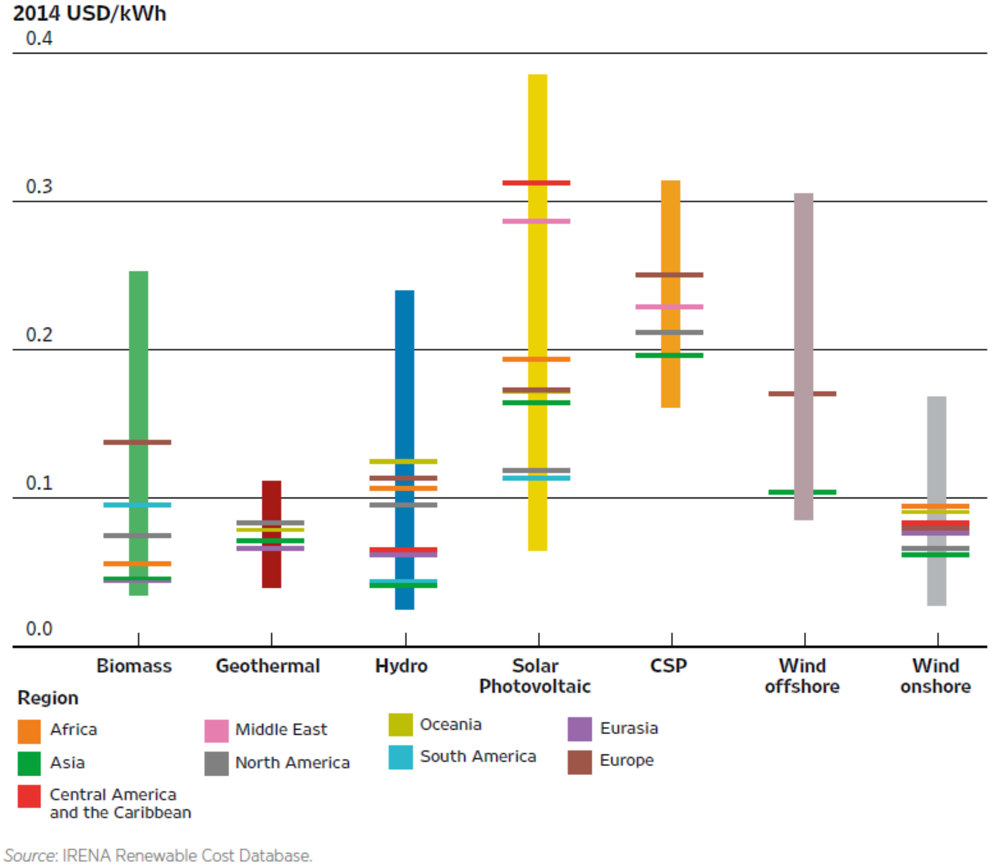

Figure 25. Typical levelised cost of electricity ranges and regional weighted averages by technology, 2013/2014. Source: IRENA 2015.

6.1.4 Norwegian LCOE estimates

The Norwegian Water Resources and Energy Directorate published a handbook in 2011 of the costs of power production in Norway (NVE 2011). The report is more detailed in the presentation of the assumptions than the WEC (2013) report making it easier to assess. The prices are originally in Norwegian January 2011 crowns, which are here converted to euros of 2011 with an exchange rate of 7.78 NOK/EUR[12].

Using the data in NVE (2011), we can assess the electricity production cost of a 400 MW CCGT, a 600 MW coal power plant and onshore wind power. The resulting assessments are shown in Figure 26.

[12] The European Central Bank rate 3.1.2011. http://www.ecb.europa.eu/home/html/index.en.html

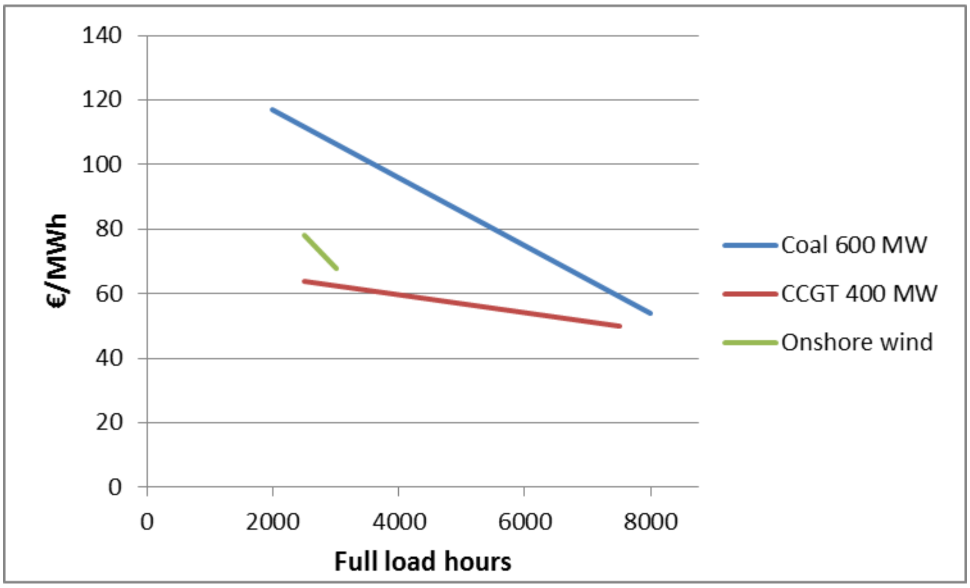

Figure 26. Effect of full load hours on levelised production costs of coal power, combined cycle gas turbine and wind power. Source of derived data: NVE 2011.

6.1.5 Swedish LCOE estimates

Swedish LCOE presented here are based on the Swedish Elforsk report by Nohlgren et al. (2014). The costs have been determined using realised investment costs etc. and for CHP units the corresponding heat costs are subtracted. The costs are presented both excluding and including Swedish policy instruments such as EU ETS, sulphur tax and electricity (green) certificates. If included, a value of 50 SEK/t_{CO2} (~5.4 €/t_{CO2}) is assumed for EU ETS and 190 SEK/MWh_e (~20 €/MWh_e) for the electricity certificates.

Full load hours depend on capacity type, but for example for coal power production 8 000 hours is used and for CCGT 8 300 hours.

The cost of electricity generation for commercial technologies that only generate electricity, excluding policy instruments, with 6 and 10% cost of capital respectively is presented in Figure 27, to the left, and including policy instruments to the right. Similarly CHP technologies are presented in Figure 28.The number behind the types in the Figures expresses the unit size.

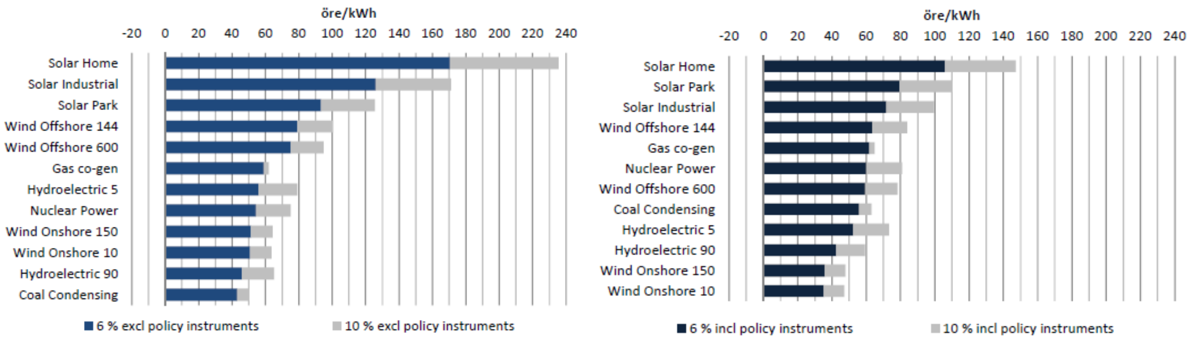

Figure 27. Cost of electricity generation for commercial technologies that only generate electricity, excluding policy instruments to the left and including to the right, with 6 and 10% cost of capital respectively. To get €/MWh, multiply the öre/kWh values with 1.08, the approximate exchange rate at the time of the source report. Source: Nohlgren at al. 2014.

Due to the policy instruments, the price of, for example, coal condensing power rises from approximately 45 €/MWh to 60 €/MWh, CCGT (here Gas co-gen) only by a few euros per MWh to roughly 65 €/MWh.

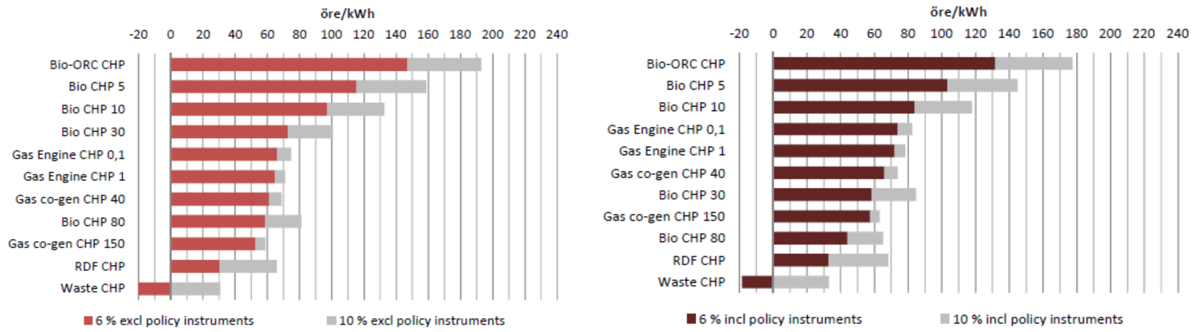

Figure 28. Cost of electricity generation for commercial CHP technologies, excluding policy instruments to the left and including to the right, with 6 and 10% cost of capital respectively. To get €/MWh, multiply the öre/kWh values with 1.08, the approximate exchange rate at the time of the report. Source: Nohlgren at al. 2014.

ORC CHP in Figure 28 refers to Organic Rankine Cycle which is a small-scale technology able to utilise lower temperature heat sources than traditional steam-water Rankine cycle CHP plants. Co-gen refers to combined cycle gas turbines (CCGT), RDF CHP to refuse-derived fuel (RFD) combusted in circulating fluidised beds (CFB). Bio CHP is either CFB or bubbling fluidised bed (BFB) boilers, depending on size. Waste CHP is municipal solid waste (MSW, basically the plastic garbage bags collected from homes) combusted in grate-fired boilers, which are robust enough for this type of fuel.

6.1.6 Danish production costs

A very comprehensive report set of production costs and their developments in both pdf and excel format is to be found at the Danish Energy Agency (DEA 2015). The report with technology data for generation of electricity and district heating, energy storage and energy carrier generation and conversion and its update (Energistyrelsen 2012, 2014) are very extensive and with partial estimates up to 2050. The reports, however, do not calculate the LCOE per se. Interested readers of this report are encouraged to do the math themselves of that report.

6.2 Production capacity in an energy-only Nordic market

To be profitable in an energy-only market, the LCOE have to be less than the average market price. If the costs are higher, no market oriented investment will take place.

The less full load hours a plant is in operation, and especially if the production is controllable (as it is in condensing power plants), the higher a price it will receive from the market compared to an annual average price. To clarify this, the duration curves of Nordic system and Finnish area prices are presented in Figure 29. If a plant is only in operation for, e.g. 2 000 hours and, assuming broadly, they are the most expensive hours, the market price received is 1.5 times the annual average for the Finnish area and 1.35 times the annual average for the Nordic area. Likewise, if the plant is in operation only during the winter season, e.g.1.10.-31.3., the received price will be 9% and 7% higher for the Nordic and the Finnish areas respectively.

It is also good to remember that the LCOE are mostly presented for base load with more than 7 000 full load hours for condensing power plants. If the plant will be used for intermediate or peak loads, the operating time will be shorter and the LCOE will be higher. The larger share investments form of the LCOE, the steeper will the rise of LCOE be with diminishing full load hours, as can be seen in Figure 26.

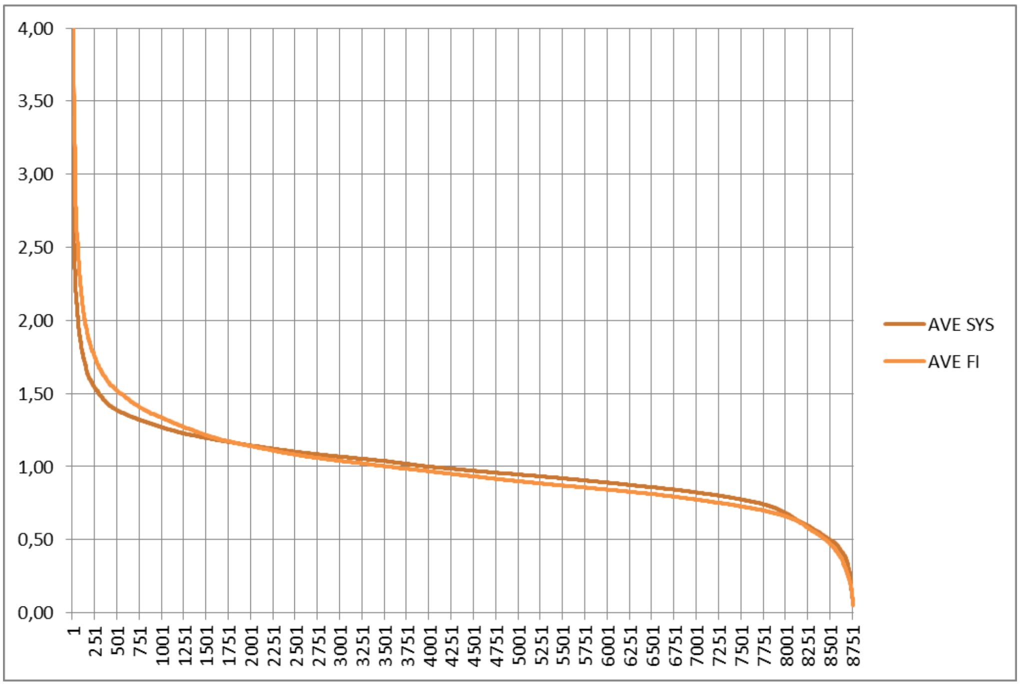

Figure 29. The duration curves of the hourly market prices at the Nordic system level as well as at the Finnish area level.

If capacity investments are unprofitable, and looking at the estimated LCOE presented in Chapter 6.1 that is not improbable, but nevertheless sought after, for security or other reasons, the operators have to be reimbursed through capacity mechanisms or other support schemes.

6.3 Active end-users in an energy-only Nordic market

The concept of active end-users should be interpreted broadly here. District heating systems can be very active prosumers in the electricity networks. Denmark, for example, has a lot of small district heating networks which are based on solar heating, heat pumps, seasonal heat storages, and CHP, as well as large DH networks using electric boilers, heat storages and CHP. These are basically already performing as smart end-users or prosumers for the power system. Depending on the price of electricity, and the heat situation, electricity is either used or produced in the heat sector.

Whereas district heating flexibility solutions are market based in the energy-only Nordic market already today, so are also small end-user solutions. Electric heated houses – this includes half a million single family houses in Finland – are a source of flexibility based on heating, especially if the heating systems include heat storages. The flexibility is, however, already in use with time-of-use tariffs, for example a day-night tariff. There is not much profit to be made in the electricity market by increasing the activity of a house warmer as Similä et al. (2011) show. The same can be assessed for electric vehicles (EV). Smart charging benefits for the owner are estimated to be around 30 € per year, but if the charging serves the upholding of power system (reserves etc.), the system benefits are over 200 € per year per vehicle (Ruska et al. 2010).

From an electricity market (spot, intraday, regulation) perspective, there is no reason to assume that introduced general capacity mechanisms would include or benefit particularly active small scale customers. The flexibility of small scale end-users is best used and paid for by the transmission or distribution system operator for auxiliary reserve purposes. If it is desired that it should be used in the market, no capacity mechanism is needed. Instead, persuade end-users to use spot price tariffs (and have smart charging of EVs set to be mandatory).

6.4 Synthesis

On a European level, looking for example at the LCOE estimates of the IEA for Germany, where the spot market price is close to the Nordic, excluding nuclear only coal CHP-fired shows signs of having the potential to be of interest to investors on a purely market base, without subsidies. Condensing power does not show any promise.

One of the main questions in the Nordic energy-only market concerns the issue of whether the circumstances will be favourable for market-based capacity investments in the future. Market-based power plants have been built during the last 20 years. Potential for capacity investments in the Nordic area is limited: Unused hydro resources are very limited (except in Norway), the heat load suitable for CHP production is not growing and nuclear is politically problematic. The only generation classes that can grow are wind, PV and conventional condensing. The last mentioned class is based on burning and avoiding climate effects makes in the long run only slightly or non-polluting fuels acceptable, examples of these are RDF and biomass.

The Nordic market price in 2035 will be around 55 €/MWh with a CO_2 price of around 30 €/t_{CO2}(Base scenario). If the world and Europe commit themselves to restrict the global warming to 2 °C, the 450 scenario, the price will be over 90 €/MWh with a CO_2 price over 100 €/t_{CO2}.

If the Nordic LCOE are similar to those of the German, coal CHP is the one showing promise. For political reasons[13], as coal is abhorred, new coal-based CHP's are not to be expected. Wind joins this elusive rank of profitability in the high market price scenario. Looking at the WEC and IRENA estimates, which do not properly represent CHP, only wind can be seen as a making it to the market, at good locations even in the base scenario.

Looking at the Norwegian estimates we see that wind is an alternative in the high price scenario. As the Swedish estimates are more diverse, we can see that bio-CHP will become profitable if the market price is higher. What is clear is that condensing power is not a solution for the market. If new capacity is needed for the management of intermittent RES-E, and that is a big and interesting if, it has to be reimbursed otherwise. The Nordic countries have great opportunities for flexibility with a high heat demand and widespread district and electric heating.

7. Summary and conclusions

The current capacity question discussion is motivated by the effects of increasing renewable electricity on the electricity system and on the profitability of conventional plants. These factors can be seen as the main drivers for the current discussion on *capacity question* in the EU.

In the Nordic electricity system the majority of production is based on hydro and nuclear and complemented by wind power and combined heat and power (CHP) production. Conventional condensing power production has only a tiny market share. Wind power's market share is on the rise and that trend is going to last for the next decade, at least.

Will the Nordic and Finnish electricity systems need intermediate or peak power plants in the future, especially as the nuclear power plants may phase out around 2030? If we do need

[13] The EU ETS is not always comprehended by politicians. Anti-carbon local actions forcing the shutdown of high efficiency coal CHP power plants to reduce GHG emissions fail to grasp that this allows for the same amount of emissions to be released from, e.g. low efficiency brown coal condensing power plants somewhere else in Europe.

them, would it be more economical to retain the old plants being shut down now or in the nearest years?

According to the theoretical analysis of investment under uncertainty, a price level corresponding to the average production cost does not induce investments. The price must stay for long periods on a much higher level before we can expect any new purely market-based investments to appear.

In this report and in this task of the SGEM project in general, two basic types of capacity solutions were identified. The solutions may be used in parallel or intertwined.

- Smart Grid related: more active demand side, real-time measurements, and information, to improve the electricity market shortcomings.

- Capacity mechanisms: increasing interest it the EU, e.g. late-2014 introduction in Great Britain.

Smart Grid technologies have potential to move electricity markets in the direction of ideal markets. That is, as more real-time measurements, information, and more active demand side can be introduced in the future electricity markets thanks to Smart Grid technologies, traditional weaknesses of electricity markets, such as lack of demand side flexibility, can be improved on. Capacity mechanisms, Smart Grids and active end users can be seen as alternative or complementary methods to tackle the development needs in electricity markets. Modern capacity mechanisms such as the one implemented in GB can deploy demand response and other Smart Grid features.

Profitability of condensing power plants is seen as a key question related to need of capacity solutions. According to simulations concerning Nordic electricity markets, assuming the increase of RES goes according to national plans, we see that condensing power production in the Nordic market in 2035 in a normal hydro year is in the range of 4 to 6 TWh. As the base case simulation for 2015 amounts to 12 TWh, the results suggest that condensing power in the Nordic is on a diminishing path towards 2035. The market price difference between the Finnish area and the Nordic system price is mainly very small, indicating only faint bottlenecks in the future, so what goes for the Nordic market also goes for the Finnish.

The result illustrates one of the key aspects of the capacity question: the position of condensing power plants seems to be threatened, assuming the development of Nordic RES, nuclear, CHP, and other capacity as described. However, flexibility characteristics of condensing production abstracted away in the model might justify at least part of the capacity staying in the market.

Comparisons of the assessed market price to the levelised cost of electricity of different production types, using various sources, were conducted. According to the results, the environment for market based investments seems to be challenging, most strikingly in scenarios with a modest or no CO_2 price increase. This strengthens the case for the need of a capacity solution for example in Germany. In the Nordic market, as our study shows, the future market price is too low to induce much else than CHP and wind in addition to hydro (with potentials only in Norway) and possibly wind and nuclear. If new condensing power capacity is needed for the management of intermittent RES-E, and that is a big and interesting if, it has to be reimbursed otherwise. The Nordic countries have great opportunities for flexibility with a high heat demand and widespread district and electric heating.

The electricity certificates in Norway and Sweden and different RES support schemes are, however, the solution for the nearest years in introducing new capacity to the market. To keep old unused capacity lingering, the peak capacity reserve remunerations in Finland and Sweden are the answer for the nearest years.

Even if one-fits for all solution cannot be specified, guidelines for Nordic/Finnish capacity solution, taking its peculiarities into account, can be drafted on the basis of task results:

- General targets of cost-efficiency and minimization of market disturbances should be taken into account.
- The current capacity supply situation and development in Nordic provides some time for considerations.
- Renewables are developing rapidly and even approaching profitability. Provided the development continues, market-based break-through of the most cost-efficient technologies might be enabled by modest price increase in the coming years.
- National capacity mechanisms might have a negative impact on the market integration viewpoint, which is seen as one of the most successful features of the Nordic market.
- The dependence of the Nordic system on hydro power highlights the need for back-up capacity for dry years unless the Nordic countries are net exporters in normal years, which forms a buffer.

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