DEMAND AND SUPPLY OF FLEXIBILITY

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Contact details

Name	Email	Telephone
Oliver Pearce	oliver.pearce@poyry.com	+358103326078
Jimmy Forsman	jimmy.forsman@poyry.com	+358103349319

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EXECUTIVE SUMMARY

Pöyry was commissioned to conduct a fundamental quantitative scenario analysis on the demand and supply of flexibility in Finland in the coming years. The main areas of investigation were:

- estimation of the overall demand and supply of flexibility until 2030;
- assessment of the factors which have an impact on the demand or supply of flexibility; and
- flexibility potential from residential customers with electric heating.

This analysis focused on the technical aspect of flexibility (MW) and did not look at the value of flexibility or cost of provision.

Under the assumed scenario, Pöyry's analysis indicates that insufficient availability of short-term flexibility is unlikely to occur when not accounting for power plant or interconnector outages.

Demand for flexibility through changes in demand and wind production is expected to increase moderately by 2030.

- The increase in wind forecast error due to growth in wind power capacity is compensated by increased forecast accuracy.
- Increase in total forecast error - defined as the combination of wind and demand forecast errors - is compensated by negative correlation between the two errors.
- Demand remains the main contributor for hourly swings.
- The analysis does not include outages – a recent Nordic TSO study on capacity adequacy for 2025 estimated that shortages can occur in Finland on cold, non-windy days with power plant or interconnector outages.

The likelihood of **supply of flexibility** being less than the demand for flexibility was found to be very low. The margin between supply and demand is less than 500 MW only 0.3 h/a in 2024 when the situation is the tightest.

- Supply of flexibility remains fairly stable until 2025 and increases between 2025 and 2030 with additional interconnector and nuclear capacity which releases interconnector capacity for balancing.
- Up-regulation potential is driven by available interconnector capacity for additional imports to Finland and Finnish hydro and CHP availability as well as industrial demand-side flexibility.
- Periods of low down-regulation potential are likely to occur during hours of high wind production and low hydro production. This is based on a conservative scenario where wind power is not providing down-regulation.
- These findings are based on one scenario of the future system development, other scenarios are possible.

The economic case for adopting flexible heating (and impact on demand profiles) by residential customers is heavily driven by the retail tariff structure: investment in flexible heat enablers (control systems) becomes economically feasible for the majority of customers by 2030 in the modelled scenarios for power-based tariffs and higher wholesale price volatility.

- Capacity based tariffs or increased wholesale price volatility are incentives to install flexible heating solutions.
- Exposing households to hourly prices unlocks the value of residential flexibility and reduces the annual electricity bill.
- Charging the grid fees based on peak demand has the potential to flatten residential demand profile.
- Flexible space and water heating brings benefits to households if no other forms of flexibility are applied (EV or battery). However, it is unclear how much the EV storage capacity would be used to optimise household retail bills or whether EV charging is optimised separately.

- If customers react to wholesale prices, they will have a lot of up-regulation potential during short periods of time, but mostly during the night. Optimising against capacity-based grid tariffs provides a smoother flexibility potential profile.

Due to the uncertain nature of power system development, new sources of flexibility should be allowed to develop – the impact will be a more robust Finnish power system and potentially lower costs for consumers

There are several possible future configurations of supply and demand of flexibility – it is prudent to ensure all flexibility measures are available, even though the scenario underlying this analysis shows little urgent need.

- Demand for flexibility will increase with more variable renewable generation entering the system and the rate of deployment is uncertain.
- Supply of flexibility comes from a variety of sources but the realisation is not certain e.g. CHP is replaced with heat-only boilers, new nuclear is delayed beyond 2030 etc.

Supporting innovation and incorporating new technologies has the potential to bring down the cost of flexibility.

- European markets for flexibility - intraday and balancing - which are introduced in the coming years can increase the competition for flexible Nordic resources thus bringing up prices.
- Demand side has significant unused potential, both on the industrial side and residential flexibility, according to interviews and analysis reported in this study.
- As an example, the price of Finnish frequency-controlled disturbance reserve decreased by over 40% after allowing that the reserve provider does not have to be the balance provider of the reserve unit, enabling aggregation from multiple balances.

Having a market design in place which allows for all sources of flexibility to compete in the market on equal terms provides a robust framework for different future scenarios. An efficient and competitive market incentivises investment and innovation where needed and minimises the need for short-term solutions that can lead to unwanted and potentially costly long-term consequences.

TIIVISTELMÄ

Pöyry tilattiin tekemään selvitys jouston kysynnästä ja tarjonnasta ja niiden ajureista Suomessa tulevina vuosina. Työn päätavoitteina oli selvittää:

- jouston kysynnän ja tarjonnan kehittyminen vuoteen 2030,
- kysyntään ja tarjontaan vaikuttavien tekijöiden arviointi, ja
- sähkölämmittäjien kysyntäjoustopotentiaali.

Selvitys tarkasteli joustoa teknisestä näkökulmasta (MW) eikä jouston arvoa tai jouston tarjonnan kustannusta ole tarkasteltu.

Skenaario-oletusten perusteella Pöyryn analyysi osoittaa, että lyhytkestoista joustoa on riittävästi saatavilla, mikäli voimalaitosten tai siirtoyhteyksien vikaantumisia ei huomioida.

Jouston kysynnän odotetaan kasvavan vuoteen 2030 mennessä, mutta vain maltillisesti.

- Tuulivoiman ennustevirheen kasvua kompensoi parempi ennustetarkkuus, joten ennustevirheen ei odoteta kasvavan samassa suhteessa tuulivoimakapasiteetin kanssa.
- Kokonaisennustevirheen kasvua kompensoi lisäksi negatiivinen korrelaatio tuulivoiman ja kysynnän ennustevirheiden välillä: nämä ennustevirheet kompensoivat toisiaan.
- Suurimmat tuntien väliset vaihtelut nettokysynnässä (kysyntä vähennettynä tuulivoiman tuotannolla) ovat pääosin kysynnän aiheuttamia, mihin ei odoteta merkittäviä muutoksia.
- Vikaantumiset eivät ole kuuluneet tähän tarkasteluun – juuri julkaistu pohjoismaisten kantaverkonhaltijoiden selvitys tehon riittävyydestä vuonna 2025 arvioi, että tehopula Suomessa on mahdollista, jos voimalaitosten tai siirtoyhteyksien vikaantumisia tapahtuu kylminä ja tuulettomina päivinä.

Todennäköisyys sille, että **jouston tarjonta** on pienempi kuin jouston kysyntä, todettiin olevan hyvin pieni. Tarjonnan ja kysynnän välinen ero on alle 500 MW vain 0,3 tuntia/vuosi vuonna 2024, kun tarjonnan ja kysynnän välinen ero on pienin.

- Jouston tarjonta pysyy melko vakiona Olkiluoto 3. yksikön käyttöönoton jälkeen vuoteen 2025 asti, minkä jälkeen lisääntyvä siirtoyhteys- ja ydinvoimakapasiteetti vapauttaa siirtoyhteyskapasiteettia järjestelmän tasapainottamiseen.
- Ylössäätöpotentiaalin tärkeimmät lähteet ovat siirtoyhteyskapasiteetti, kotimainen vesi- ja yhteistuotantovoima sekä teollinen kysyntäjousto.
- Alhaiset alassäätöpotentiaalin jaksot tapahtuvat yleensä korkean tuulivoimatuotannon ja alhaisen vesivoimatuotannon aikoina. Tämä perustuu konservatiiviseen skenaarioon, missä tuulivoima ei tarjoa alassäätöä.
- Nämä tulokset perustuvat yhteen skenaarioon järjestelmän oletetusta kehityksestä – muut skenaariot ovat mahdollisia

Vähittäismarkkinoiden tariffirakenne voi vaikuttaa merkittävästi sähkölämmittäjien kysyntäjouston kannattavuuteen ja kulutusprofiiliin: investoinnista kysyntäjoustoratkaisuihin tulee kannattavaa valtaosalle asiakkaista vuoteen 2030 mennessä mallinnetuissa skenaarioissa tehotariffeille ja korkeammalle tuntihintavolatiliteetille.

- Tehoon perustuvat verkkomaksut ja lisääntynyt tuntihintavolatiliteetti ovat insentiivejä asentaa kysyntäjoustoratkaisuja kotitalouksien sähkölämmityksen yhteyteen.
- Sähkölämmityksen kysyntäjousto ja tuntihintasopimus mahdollistaa kulutuksen siirtämisen kalliilta aamu- ja iltapäivätunneilta halvemmille yön tunneille.
- Verkkomaksujen veloittaminen käytetyn huipputehon mukaan voi kuitenkin johtaa lähes tasaiseen kulutusprofiiliin, vaikka käytössä olisi tuntihintaan perustuva sopimus.
- Joustava sähkölämmitys tuo hyötyjä kotitalouksille, joissa ei ole muita jouston lähteitä (sähköautot tai sähkövarastot). On kuitenkin epäselvää, miten paljon sähköautojen akkujen

varastokapasiteettia käytettäisiin optimoimaan kotitalouden sähkölaskua vai optimoidaanko sähköauton latausta erikseen.

- Tuntihintoihin reagoivilla asiakkailla on paljon ylössäätöpotentiaalia muutaman tunnin ajanjaksoissa, yleensä öisin. Tehotariffeja vasten optimointi johtaa tasaisempaan jouston tarjonnan profiiliin.

Järjestelmän kehittymiseen liittyvän epävarmuuden vuoksi uusia jouston lähteitä tulisi kehittää – johtaen erilaisiin tilanteisiin paremmin mukautuvaan sähköjärjestelmään ja mahdollisesti alhaisempiin kustannuksiin sähkön loppukäyttäjille

Jouston kysynnän ja tarjonnan kehitykselle on monia vaihtoehtoisia kehityskulkuja – on järkevää varmistaa, että kaikki vaihtoehdot ovat käytettävissä, vaikka tässä selvityksessä käytetyssä skenaariossa välitöntä tarvetta ei löydetty operatiivisesta näkökulmasta.

- Jouston kysyntä tulee lisääntymään uusiutuvan sähköntuotannon lisääntyessä ja käyttöönoton nopeus on epävarma.
- Jouston tarjonta tulee useista lähteistä, mutta niiden toteutuminen ei ole varmaa: esim. yhteistuotantolaitoksia saatetaan korvata lämpölaitoksilla, uudet ydinvoimalaitokset voivat tulla järjestelmään vasta vuoden 2030 jälkeen.

Uusien teknologioiden käyttöönotolla ja innovaatioiden tukemisella voidaan laskea jouston tarjonnan kustannuksia.

- Eurooppalaiset markkinat joustavuudelle – päivänsisäiset ja kantaverkonhaltijoiden markkinapaikat – jotka otetaan käyttöön seuraavina vuosina, voivat lisätä kilpailua joustavista pohjoismaisista resursseista mahdollisesti nostaen näiden hintoja.
- Sidosryhmähaastattelujen ja tässä työssä tehdyn analyysin perusteella kysyntäjoustossa on paljon hyödyntämätöntä potentiaalia, teollisuudessa ja kotitalouksissa.
- Esimerkiksi taajuusohjatun häiriöreservin hinta putosi yli 40 % sen jälkeen, kun markkinapaikalla sallittiin taseketjun ulkopuolisen toimijan toimia reservitoimittajan roolissa, mikä mahdollistaa usean taseen resurssien aggregoinnin.

Markkinasäännöt, jotka sallivat kaikkien jouston lähteiden kilpailla tasavertaisesti markkinoilla, mahdollistavat eri tulevaisuuden skenaarioihin mukautuvat sähkömarkkinat. Tehokkaat ja kilpaillut markkinat kannustavat investointeihin ja innovaatioihin siellä, missä niitä tarvitaan, ja minimoivat tarpeen lyhyen aikavälin ratkaisuille, joilla saattaa olla ei toivottuja ja mahdollisesti kalliita pitkän aikavälin vaikutuksia.

1. INTRODUCTION

1.1 Background and objectives

Pöyry was commissioned to conduct a fundamental analysis on the demand and supply of flexibility in Finland in to 2030.

The need for flexibility has been the focus of two major market design projects in Finland:

- Fingrid's 'Johtokatu' paper detailing a set of market design improvements which are directed toward pricing flexibility appropriately and improving market access for different types of flexible resources; and
- The Smart Grid Working Group, aiming at making customers connected to the distribution grid more active in the electricity market and making their flexible resources available in the market.

Fingrid is also running several pilot projects to e.g. test different aggregation models in its balancing market and publishing the balancing price in real time in scarcity situations to increase the supply of flexibility.

The purpose of the study was to evaluate the demand and supply of flexibility in the future. The key objectives were to:

- Estimate the overall demand and supply of flexibility in the Finnish market until 2030;
- Assess the factors which have an impact on the demand or supply of flexibility; and
- Assess the impact of certain market design proposals discussed in the Smart Grid working group on the supply of residential demand side flexibility in the Finnish market.

1.2 Scope and approach

Demand and supply of flexibility were analysed through a combination of historical data analysis, stakeholder interviews and modelling of future development based on the following approach:

- Demand for flexibility
  - Two metrics were used for demand for flexibility: forecast errors and 'hourly swings'
    - Forecast error is defined as the difference between day-ahead or hour-ahead forecast and the actual out-turn
    - Hourly swing is defined as the difference between demand minus renewable generation between two consecutive hours
  - The major drivers for forecast errors that are investigated are:
    - Demand forecast errors, mainly due to temperature; and
    - Wind forecast errors.
- Supply of flexibility
  - In general, there are four possible sources of flexibility: flexible generation, interconnection, demand-side response and storage
  - Pöyry's electricity market model outcomes were used as baseline for hourly profiles or consumption, production and cross-border exchange
  - Based on this baseline we have estimated the amount of flexibility different resources in the power system can provide
  - In addition, the study includes a sensitivity analysis on residential flexibility, focusing on electric heating

Further details on the approach used are presented in section 2.1 (demand for flexibility) and section 3.1 (supply of flexibility).

1.3 Recent studies on flexibility

During the recent years, several studies have been conducted on power adequacy and sources of flexibility in the Finnish power system. This section presents the main conclusions from these studies. In summary, there have been two main focus areas in these studies: capacity adequacy and demand-side response. This study aims to add to this knowledge by providing insights into the demand and supply balance of short-term flexibility in the Finnish power system through quantitative analysis throughout the year, i.e. not only focusing on periods of high demand.

Defining flexibility

Flexibility in the power system has become a very topical term, which can mean many different things. Flexibility is the modification of generation injection and/or consumption patterns in reaction to an external signal (price signal or activation) in order to provide a service within the power system.

The parameters used to characterise flexibility include[1]:

- amount of power modulation;
- duration;
- rate of change;
- response time; and
- location.

Demand for flexibility and power adequacy

The latest mid-term adequacy forecast by the Nordic TSOs[2] found that a power deficit would occur in Finland during peak hours, if there was an outage of at least two large power plants or an interconnector together with cold and non-windy weather conditions in their base case for 2025. In addition, the study found that Finland is the only country in the Nordics that would have a non-zero loss of load expectation for that year.

In 2016, Pöyry published a report on the need for peak load capacity in Finland during 2017-2022.[3] According to the study, the probability for a power deficit during peak load hours without reserve would drop significantly after 2019, once Olkiluoto 3 nuclear power plant is commissioned. Under the assumptions used in the study, the cost-efficient amount of reserve was estimated to be 0-400 MW based on the cost of capacity and the value of lost load for customers before the commissioning of Olkiluoto 3, after which there would be no further need for reserves. The findings were similar in a previous study for the same purpose by VTT in 2014 for the period of 2015-2020.[4] The expected values of energy deficit were found to be low, and it was considered more profitable to have, e.g., circulating power outages, if the power deficit would despite its unlikeliness occur.

An analysis by EL-TRAN in 2016 discussed the record high hourly electricity demand in January 2016.[5] The study examined the shares of different loads during the record high demand, and what factors could cause similar events in the future. According to the study, short periods of high demand and the variability in supply would further increase. The study pointed out that during the industrial demand was close to an average level and consumption in buildings covered more than two-thirds of the spike. The key conclusion of the analysis was that more attention should to be paid to power, and not only energy, in the Finnish power system, considering also retail pricing and consumption.

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[1] See, e.g. Bundesnetzagentur: https://tinyurl.com/y9bpk2xq

[2] Source: Nordic perspectives on mid-term adequacy forecast 2017. Available at: https://tinyurl.com/y9o4lrpl

[3] Source: Pöyry. Selvitystyö tarvittavasta tehoreservin määrästä ajanjaksolle 2017–2022. https://tinyurl.com/ycobw2sm

[4] Source: VTT. Selvitys tehoreservin tarpeesta vuosille 2015–2020. Available at: https://tinyurl.com/y88ltdg4

[5] Source: EL-TRAN. Tammikuun tehopiikki – mitä tapahtui 7.1.2016? Miten tehoa hallitaan paremmin jatkossa? Available at: https://tinyurl.com/y7fu663x

A master's thesis by Laitinen, which was commissioned by Fingrid, studied the intra-hour power balance in Finland in the 2020s.[6] The objective of the study was to find out whether the existing regulating resources meet the future regulating needs. The study found that there is a possibility for balancing deficits during periods of high demand and low wind production when there are bottlenecks in the interconnectors between Finland and Sweden and domestic hydro production is running at full capacity.

Supply of flexibility

Research by the Tampere University of Technology published in 2015 studied the technical and economic potential of demand-side flexibility provided by different types of non-industrial demand in Finland.[7] The study assessed the technical potential of different types of flexible loads. The technical control potential of some of the most potential groups of loads was:

- direct electric heating: 1,800 MW;
- hot water boilers: 1,200 MW;
- electric heating with storage: 1,300 MW;
- ventilation in buildings: 400 MW; and
- greenhouses: 300 MW.

According to the study, the difference in the flexibility potential varies considerably according to seasonal, daily and hourly variations in the load profiles.

In 2014, Pöyry published a report mapping out the most potential sources of industrial and commercial demand-side flexibility in Finland.[8] The study found that the largest potential is found from energy-intensive industries, i.e. forest, metal, and chemical industries, even though these industries already provide demand-side response to the market. Unused flexibility potential was also found from several new sectors, such as extractive, machinery, water processing and greenhouses.

1.4 Future scenario assumptions

As part of this study, we have modelled the European, Nordic and Finnish power market until 2030 on an hourly (8760 h/a) basis. The assumed scenario presents Pöyry's current best view for the likely capacity evolution of the Finnish, Nordic and all other European markets. The scenario is focused on an underlying set of market assumptions that reflect our standard view of evolution of the Finnish, Nordic and European power market. In order to evaluate the impact that other pathways could have, sensitivities around the core scenario have been investigated.

Further details on the main scenario assumptions are presented in the following sections.

Finnish market outlook

Figure 1-1 presents the main scenario assumptions used in this study. The main assumptions for Finnish market developments are as follows:

- Wind capacity is estimated to increase to 2.6 GW after the next auction round and to reach 3.4 GW by 2030.
- Nuclear capacity include the introduction of Olkiluoto 3 (1600MW in 2019), and the commissioning of Hanhikivi (1200MW between 2025 and 2030). Loviisa unit 1 is expected to decommission around 2027, reducing nuclear capacity by 488MW. The second Loviisa unit is expected to be decommissioned after 2030 which is out of the time horizon of this study. By 2030 nuclear contributes 45% of Finnish generation volumes.

[6] Source: Laitinen, L. Tunninsisäinen tehotasapaino suomessa 2020 ja 2030. Available at: https://tinyurl.com/ybnacufu

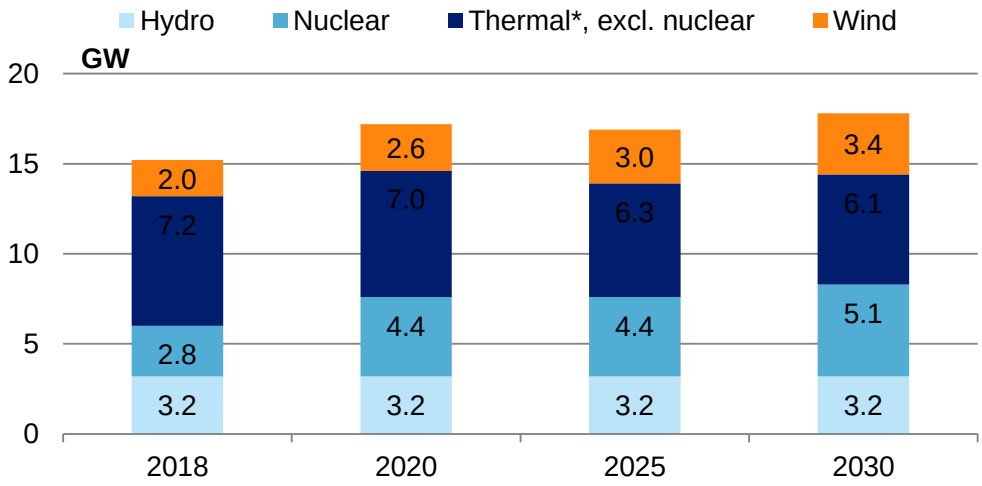
[7] Source: Tampere University of Technology. Kysynnän jousto - Suomeen soveltuvat käytännön ratkaisut ja vaikutukset verkkoyhtiöille (DR pooli). Available at: https://tinyurl.com/y7pu6uv2

[8] Source: Pöyry. Sähkön kysyntäjoustopotentiaalin kartoitus Suomessa. Available at: https://tinyurl.com/y9a8jnux

- Hydro capacity expected to remain stable at 3.2 GW.
- Thermal capacity decreases gradually, but CHP plants due to retire are largely replaced with new CHP units running on biomass.
- A new 800MW interconnector between Finland and Sweden is commissioned at the end of 2025.
- Demand is expected to remain fairly stable in the range of 86-88 TWh/a until 2030.

The level of new grid scale electricity storage is assumed to be low on a system level due to relatively low price volatility in the Nordic wholesale market i.e. Nordic hydro provides low cost flexibility. The commissioning of grid scale storage capacity is expected to be driven mainly by frequency containment reserves and e.g. back-up power solutions for distribution networks, which are outside the scope of this study.

Figure 1-1 – Expected generation capacity development



Nordic market outlook – a growing surplus

The situation in neighbouring markets is an important driver of outcomes for the Finnish market. The Nordic market is expected to see a growing power surplus under the assumed scenario. This surplus is driven by increasing generation in the Nordics (mostly wind and nuclear) and flat demand.

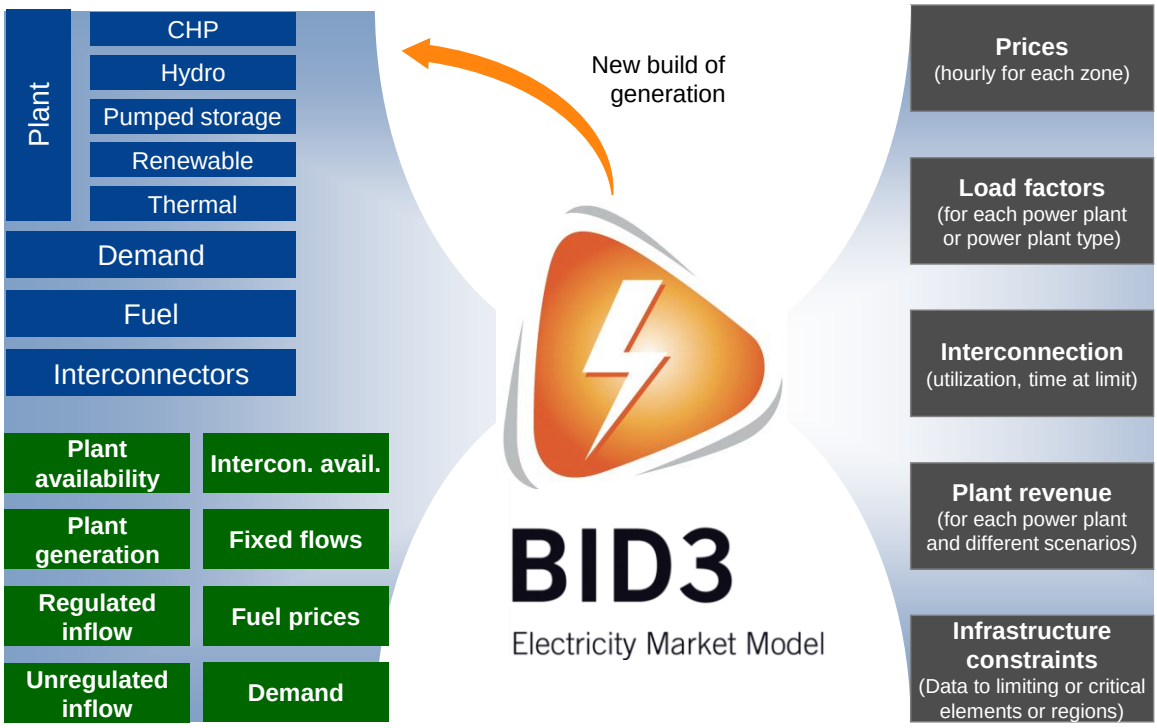
The assumed development of interconnectors leads to an increase in trade between the Nordic countries and the Continent. However, the developments are not fully sufficient to remove bottlenecks to the Continent, meaning that price differences between the Nordics and Continental Europe remain. During the analysis horizon, the following takes place:

- The total Nordic surplus rises to above 40TWh by 2030 (compared to around 9TWh today), driven by relatively flat demand, and increasing generation from new wind and nuclear in Finland
- In order to export the surplus, 8GW of new interconnection capacity between the Nordics and the Continent and GB are commissioned. External reinforcement is taken from development plans and then is based on economics
- A 25% increase in internal Nordic grid capacity to accommodate increased generation and cables to the continent. Internal reinforcement is largely taken from the latest network development plans published by each TSO.

1.5 Modelling methodology

Market Simulations have been carried out in BID3, which is Pöyry's power market model, used to model the dispatch of all generation on the European network. The model simulates all 8760 hours per year, with multiple historical weather patterns, generating hourly wholesale prices for each country for each future year and dispatch patterns and revenues for each plant in Europe.

Figure 1-2 – Overview of BID3



1.5.1 Modelling methodology

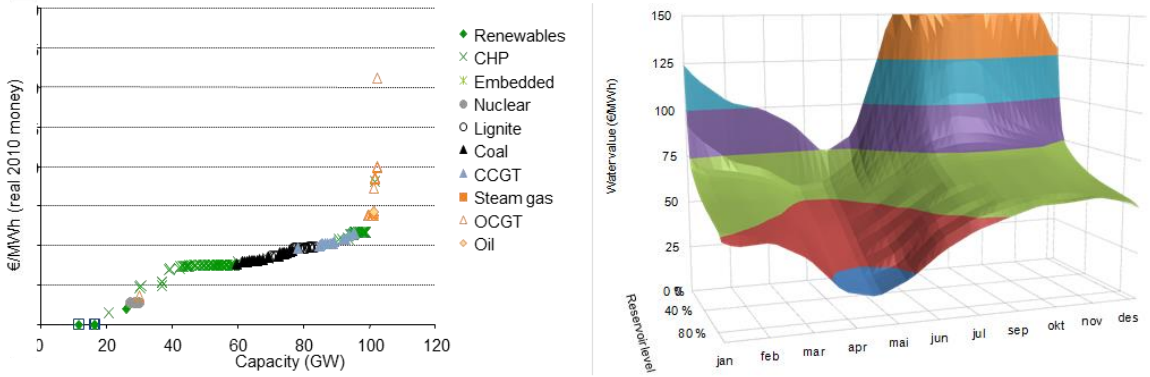
BID3 is an economic dispatch model based around optimisation. The model balances demand and supply on an hourly basis by minimising the variable cost of electricity generation. The result of this optimisation is an hourly dispatch schedule for all power plants and interconnectors on the system. At the high level, this is equivalent to modelling the market by the intersection between a supply curve and a demand curve for each hour.

Producing the system schedule

- **Dispatch of thermal plant.** All plants are assumed to bid cost reflectively and plants are dispatched on a merit order basis – i.e. plants with lower short-run variable costs are dispatched ahead of plant with higher short-run variable costs. This reflects a fully competitive market and leads to a least-cost solution. Costs associated with starts and part-loading are included in the optimisation. The model also takes account of all the major plant dynamics, including minimum stable generation, minimum on-times and minimum off-times.
- Figure 1-3 below shows an example of a merit order curve for thermal plant.
- **Dispatch of hydro plant.** Reservoir hydro plants can be dispatched in two ways:
    - a perfect foresight methodology, where each reservoir has a one year of foresight of its natural inflow and the seasonal power price level, and is able to fix the seasonality of its operation in an optimal way; or

- the water value method, where the option value of stored water is calculated using Stochastic Dynamic Programming. This results in a water value curve where the option value of a stored MWh is a function of the filling level of the reservoir, the filling level of competing reservoirs, and the time of year.
    - Figure 1-3 below shows an example water value curve.
- **Variable renewable generation.** Hourly generation of variable renewable sources is modelled based on detailed wind speed and solar radiation data which can be constrained, if required, due to operational constraints of other plants or the system.
- **Interconnector flows.** Interconnectors are optimally utilised – this is equivalent to a market coupling arrangement.
- **Demand side response and storage.** Operation of demand side and storage is modelled in a sophisticated way, allowing simulation of flexible load such as electric vehicles and heat while respecting demand side and storage constraints.

Figure 1-3 – Thermal plant merit-order and water value curve



1.5.2 Power price

The model produces a power price for each hour and for each zone (which may be smaller than one country, for example the different price-zones within Norway). The hourly power price is composed of two components:

- **Short-run marginal cost (SRMC).** The SRMC is the extra cost of one additional unit of power consumption. It is also the minimum price at which all operating plant are recovering their variable costs. Since the optimisation includes start-up and part-load costs all plant will fully cover their variable costs, including fuel, start-up, and part-loading costs.
- **Scarcity rent.** A scarcity rent is included in the market price – we assume power prices are able to rise above the short-run marginal cost at times when the capacity margin is tight. In each hour the scarcity rent is determined by the capacity margin in each market. It is needed to ensure that the plants required to maintain system security are able to recover all of their fixed and capital costs from the market.

1.5.3 Key input data

Pöyry's power market modelling is based on Pöyry's plant-by-plant database of the European power market. The database is updated each quarter by Pöyry's country experts as part of our *Energy Market Quarterly Analysis*. As part of the same process we review our interconnection data, fuel prices, and demand projections.

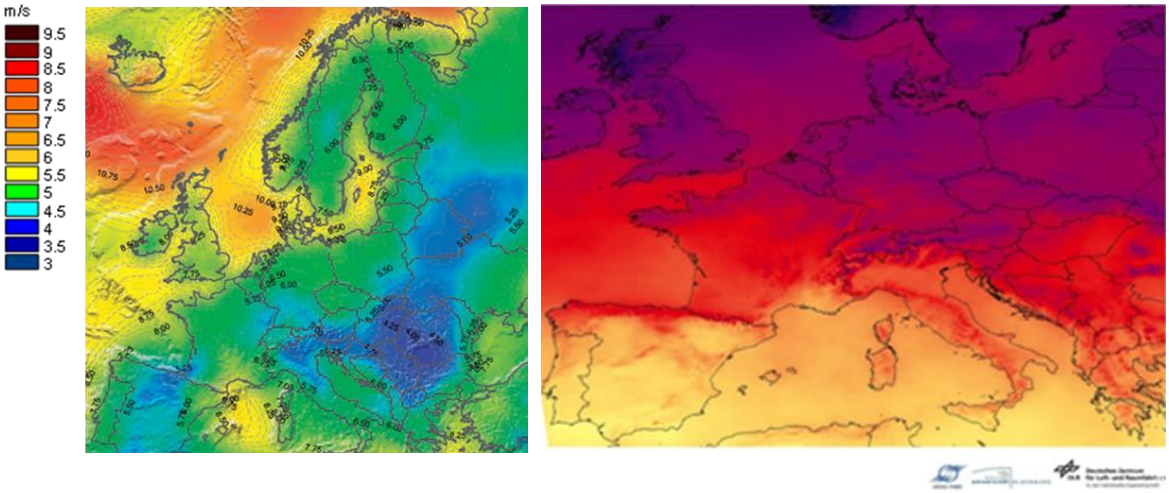
- **Demand.** Annual demand projections are based on TSO forecasts and our own analysis. For the within year profile of demand we use historical demand profiles – for each future year that is modelled we use demand profiles from a range of historical years.
- **Intermittent generation.** We use historical wind speed data and solar radiation data as raw inputs. We use consistent historical weather and demand profiles (i.e. both from the same

historical year). This means we capture any correlations between weather and demand, and can also example a variety of conditions – for example a particularly windy year, or a cold, high demand, low wind period.

- Our wind data is from Anemos and is reanalysis data from weather modelling based on satellite observations. It is hourly wind speeds at grid points on a 20km grid across Europe, at hub height. Figure 1-4 below shows average wind speeds based on this data. Hourly wind speed is converted to hourly wind generation based on wind capacity locations and using appropriate aggregated power curves.
- The solar radiation data is from Transvalor, and is again converted to solar generation profiles based on capacity distributions across each country. Figure 1-4 below shows average solar radiation based on this data.

- **Fuel prices.** Pöyry has a full suite of energy market models covering coal, gas, oil, carbon, and biomass. These are used in conjunction with BID3 to produce input fuel prices consistent with the scenarios developed.

Figure 1-4 – Average wind speeds and solar radiation in Europe

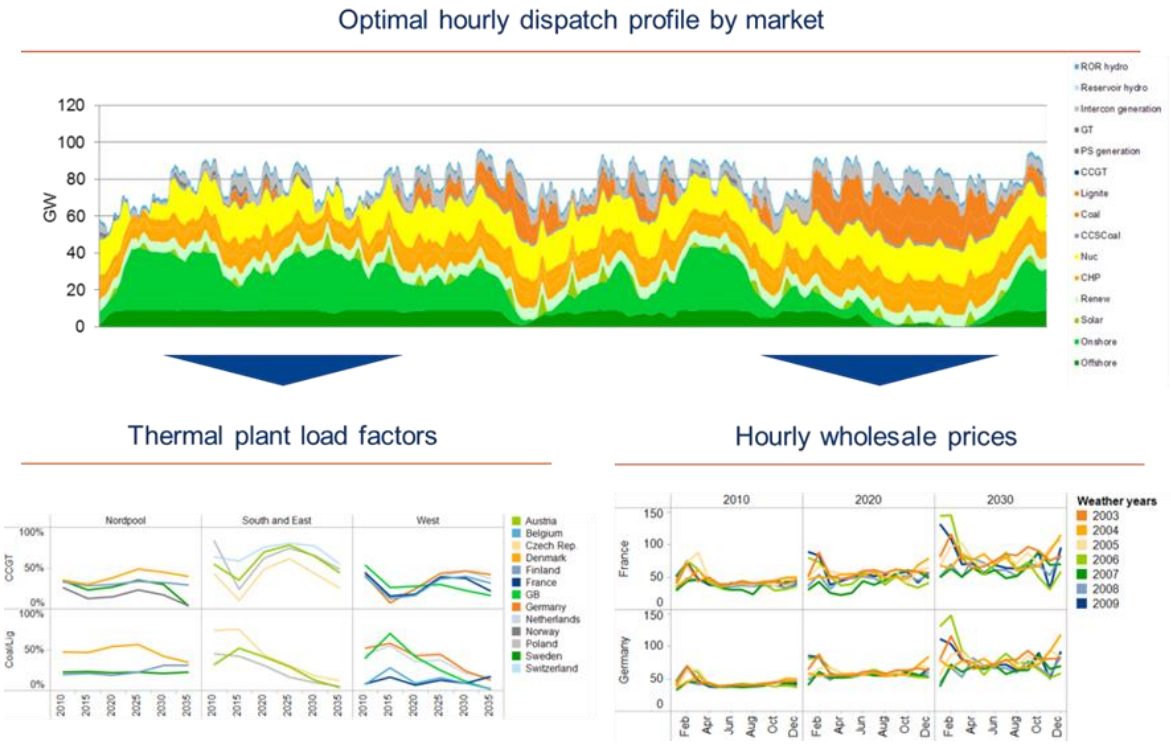


Source: Anemos, data resolution 20km by 20km Source: Transvalor, data resolution 2km by 2km

1.5.4 Model results

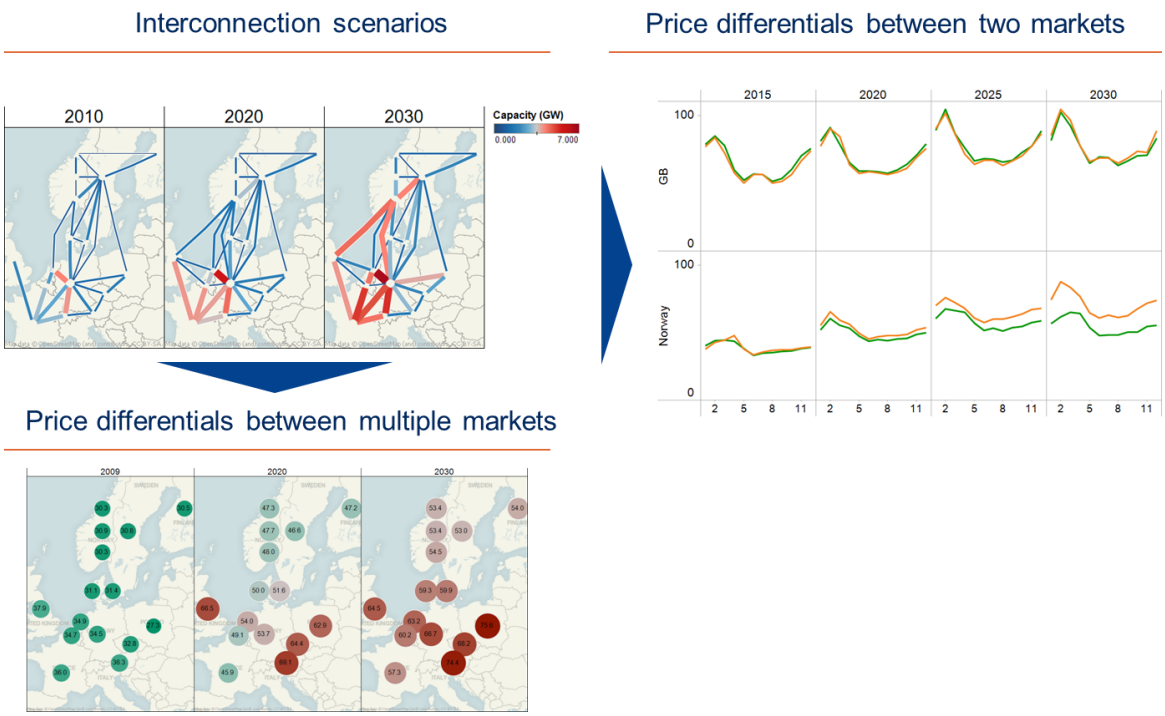
BID3 provides a comprehensive range of results, from detailed hourly system dispatch and pricing information, to high level metrics such as total system cost and economic surplus. A selection of model results is shown below in Figure 1-5 and Figure 1-6.

Figure 1-5 – Hourly dispatch and related metrics



Source: Pöyry BID3 based analysis

Figure 1-6 – Interconnector value assessment



2. DEMAND FOR FLEXIBILITY

2.1 Introduction

This chapter presents the analysis carried out to derive demand for flexibility in the Finnish electricity market and is structured in the following way:

- Section 2.2 presents the two metrics used to define demand for flexibility in this study; forecast errors and hourly swings. Both metrics attempt to quantify the need for flexibility but in slightly different ways.
- Section 2.3 looks at historical development of demand for flexibility for the years 2013 to 2017.
- Future demand for flexibility is assessed in section 2.4. The analysis presents forecasts of demand for flexibility and how this is expected to evolve to 2030.

2.2 Metrics for flexibility demand

Forecast error

Forecast errors are used as a key metric for demand for flexibility in this report. Forecast errors represent the unpredictable fluctuations in the power system that the system needs to cope with through supply of flexibility from either production or demand. Two sources of forecast errors are assessed: wind production and demand. Together these are assumed to represent forecast uncertainty in the power system for the purposes of this analysis. Solar power is not taken into account as the amount of it is expected to be minimal by 2030 in the scenario used as basis for the analysis (see Section 1.4 for more detail). This report also does not look at power plant or interconnector outages or other non-standard events as source of uncertainty and assumes the situation to be “business as usual”.

Hourly swing

Hourly swing (demand net variable RES generation, so excluding hydro), represents the residual change the system needs to respond to. Hourly swing is defined as absolute change in residual demand from one hour to the next:

$$Hourly\ swing = (Demand - RES)_t - (Demand - RES)_{t-1h}$$

2.3 Historical analysis of forecast errors and hourly swing

This section contains the following steps:

- Wind and demand forecast errors are analysed separately for two different time horizons
- The two forecast errors are combined to derive the total historical demand for flexibility
- Next we analyse the historical hourly swing and its drivers
- Potential impact of EVs (electric vehicles) on demand forecast accuracy and hourly swing are analysed using historical data from Norway

Approach for analysing historical forecast error

Forecast error is the difference between forecasted values (at a defined point before real time) and the actual out-turn. For calculation purposes forecast error is defined as:

$$forecast\ error = out\text{-}turn - forecast.$$

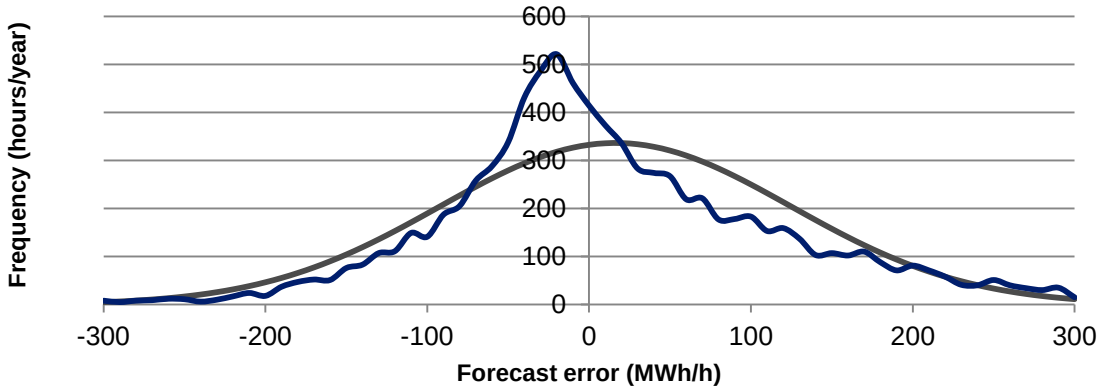
Wind and demand forecast errors together represent the unpredictable change that can happen in the system that the system must respond to with flexible production or demand. Forecast error cannot be entirely removed, hence it creates demand for flexibility.

Forecast errors are analysed through error distributions and by fitting a normal distribution on the error curves (Figure 2-1). The distribution curve shows how frequently (y-axis) certain forecast errors occur (x-axis) during a one-year period. In general, the error distribution curve is flatter and

wider when high forecast error values (in absolute terms) are likely. Conversely, the narrower and taller the curve is, the more likely low forecast errors.

Based on the data analysis, a normal distribution does not perfectly represent the error distribution. For example, in Figure 2-1, the wind forecast error is skewed compared to a normal distribution representation. As the focus of this analysis is around the tails of the distribution, a normal distribution is used (as it represents the tails of the error distribution well enough, which are important to capture when projecting future forecast error levels).

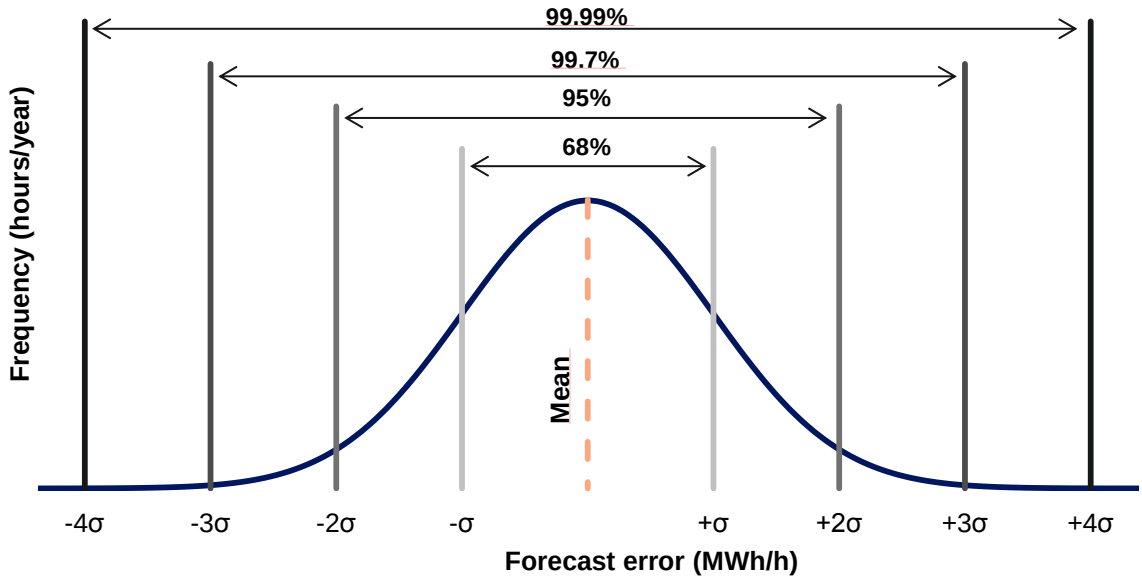
Figure 2-1 – Example forecast error distribution and a fitted normal distribution



Note: X-axis represents amount of error in MW/h and Y-axis presents the frequency of that error as hours per year

Source: Pöyry, data source: Fingrid

Figure 2-2 – Sigma multiples and corresponding percentages in standard deviation



Demand for flexibility is the deviation of the error from the zero. It shows how often the errors are within certain value limits in percentage terms. In this report we primarily look at multiples of standard deviation (σ denotes standard deviation, see Figure 2-2 and Table 2-1) and corresponding probability levels; see Table 2-1). A standard deviation multiple of 4 (99.99%) is used as measures for both demand for and supply of flexibility because it represents an infrequent enough event.

Table 2-1 – Multiples of standard deviation

Standard deviation multiple	σ	2σ	3σ	4σ
Percentage interval	63%	95%	99.7%	99.99%
Hours per year	2920 h/year	398 h/year	24 h/year	~1 h in two years

Wind forecasting

Table 2-2 shows a short description of different forecasting methods. Different techniques are used for wind forecasting based on the time horizon. Hour-ahead and 12-hours ahead wind forecasts are analysed in this report.

Table 2-2 – Forecasting models

Forecast model	Common techniques	Room for improvement
Statistical < 6 hours ahead	Calculations based on historical data i.e. past production correlates with future production Finding dependencies between produced wind power and meteorological forecasts Various different statistical and computational models available	Aggregation of sites decreased forecast errors by 30–40 %*
Physical > 6 hours ahead	Estimates the physical behaviour of wind field utilising local conditions: roughness, obstacles. Requires a lot of computing power	Improved and more effective models; more computing power More and better weather data; more sensors and measurements Improving forecasts 6 hours ahead may require measurements up to 300 km away

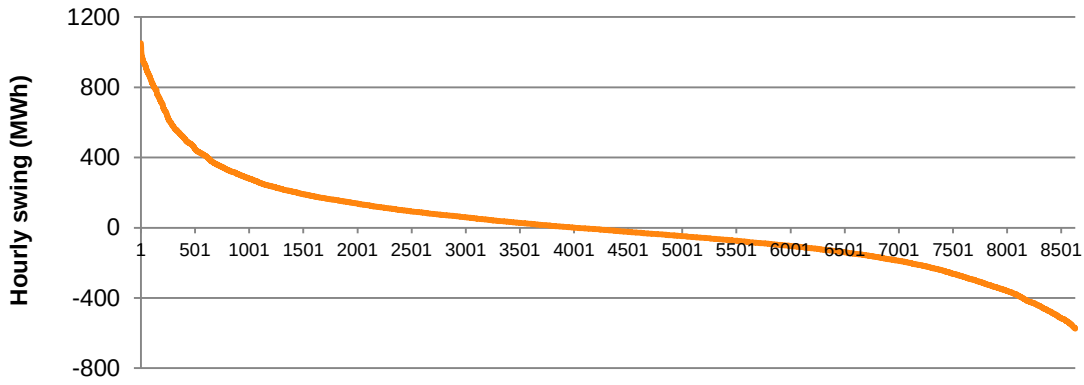
* VTT Technology 95 – Wind power forecasting accuracy and uncertainty in Finland

Hourly swing

Hourly swing shows how much flexibility is required in the system to handle differences between values of demand net renewable generation in contiguous hours, with no forecast errors.

Historical hourly swing is presented using duration curves (Figure 2-3). The duration curve plots hourly swing values over one year from largest positive swing to largest negative swings. Y-axis denotes the amount of swing between two hours (e.g. 800 MWh change between two hours) and X-axis their order.

Figure 2-3 – Example of an hourly swing duration curve (2017)



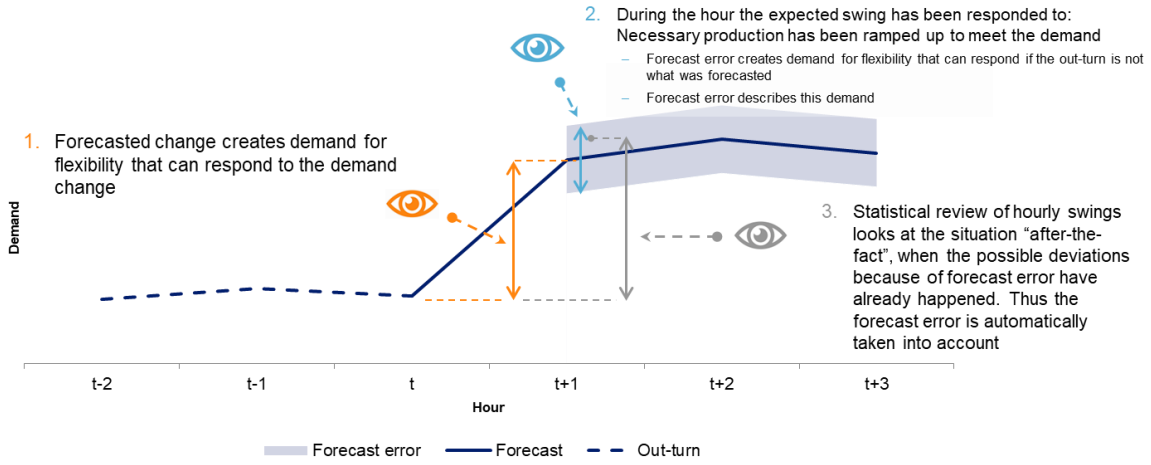
Source: Pöyry analysis, data source: Fingrid

Interpreting forecast error and hourly swing

Figure 2-4 shows how forecast error and hourly swing relate to each other and why these metrics must be treated separately in assessing demand for flexibility. Figure 2-4 presents a hypothetical situation, where:

1. At hour *t* the demand is forecasted to increase in hour *t+1.* This creates demand for flexibility that can respond to the change. As the demand change is a forecast value, the need is likely to be covered though market allocation.
2. Because of the forecast error (in this case the total forecast error, including wind production forecast error) out-turn may be above or below the forecast value. This means that the production will need to adjust.
    a. Therefore demand for flexibility in hour before (at point 1) is the expected demand *plus* the forecast error - the system needs to be able to respond to the sum of the two components. The probability range around the forecast error is analysed in this report.
3. Hourly swing (demand net RES between contiguous hours) looks at the situation after the operating hour. Any deviations from the forecasted values caused by forecast errors have already taken place. Netting the RES generation (subtracting RES generation from demand) shows how the wind uncertainty and variability impacts the realised demand swing.

Figure 2-4 – Interpreting forecast error and demand swing



Data sources

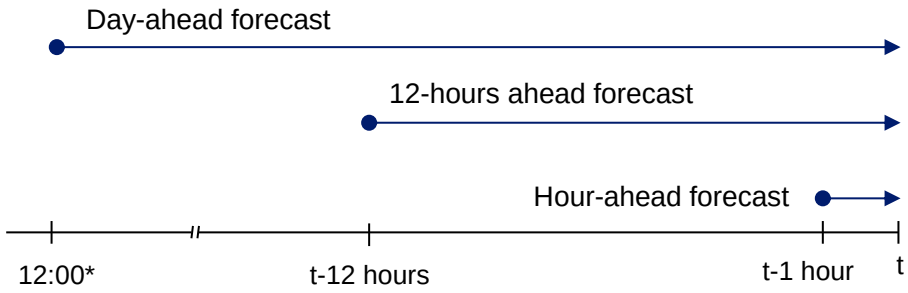
Two primary data sources were used for the analysis. All of the forecast data was provided by Fingrid and majority of the out-turn data was taken from Fingrid open data platform[9]. In addition, hourly production statistics[10] provided by Finnish Energy were used for wind production data, due to some issues with data consistency (missing values and inconsistent time stamps) in Fingrid's open data portal.

Analysis timeframes (forecast horizons and historical years) were selected largely based on data availability:

- Wind forecast data was available for two forecast horizons: hour-ahead and 12 hours ahead
- Demand forecasts were available for two horizons: hour-ahead and day-ahead forecast.

Figure 2-5 shows how the three different time horizons relate to each other and the actual operating hour that is being forecasted. The day-ahead forecast is set after day-ahead trading, 12h-ahead forecast is done 12 hours before the operating hour and hour-ahead forecast is the last forecast before the operating hour.

Figure 2-5 – Forecast time horizons



* Day-ahead forecast is set previous day

2.3.1 Historical wind forecast error analysis

Wind – 12 hours ahead forecast

Figure 2-6 illustrates the wind forecast error in years 2013, 2015 and 2017. The years 2014 and 2016 are included in the analysis but are not shown for the sake of visual simplicity.

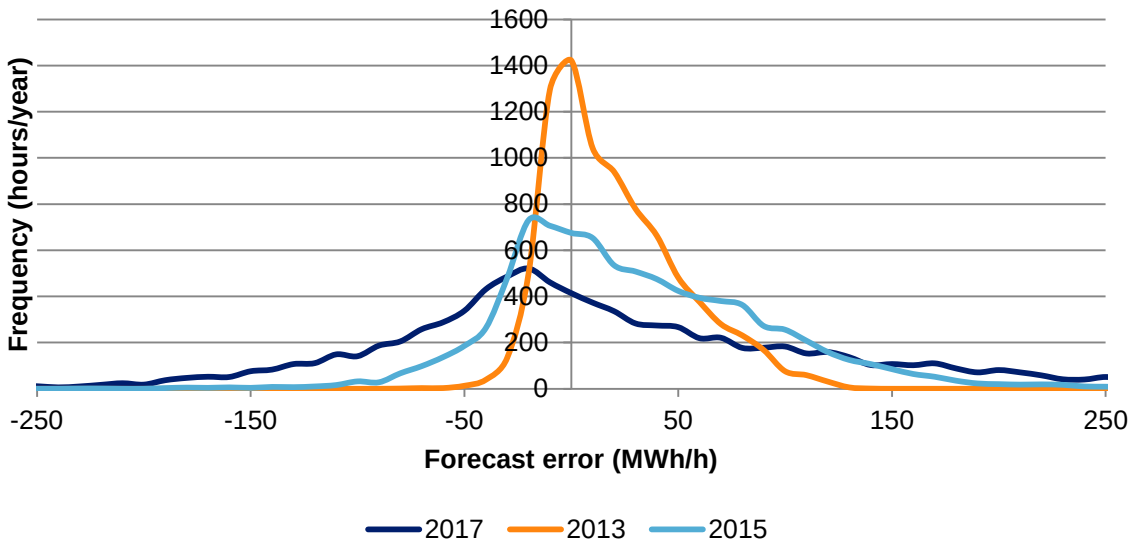
Forecast error has increased significantly from 2013, which is expected considering the large amount of wind (roughly 1.6 GW) that has entered the system between 2013 and 2017. The increase in forecast error means that the error distribution in 2017 is much wider and flatter than in 2013; large errors are more frequent and small errors less frequent.

Forecast errors are slightly skewed to the left, indicating that there is a tendency to forecast lower production compared to out-turn. Some of the difference might be explained by different data sources: the forecast data was provided by Fingrid (and the forecast itself was done by Fingrid), whereas data from Finnish Energy was used for out-turn because of issues with data completeness.

Estimated normal distribution characteristics are shown in Table 2-3. Standard deviation in 2017 is 3.5-fold compared to 2013, while at the same time wind power capacity is 4.5-fold (from 450 MW to 2050 MW), indicating a fairly strong learning curve.

[9] data.fingrid.fi
[10] www.energia.fi

Figure 2-6 – Wind 12-hours ahead forecast error distribution



Note: x-axis represents the amount of error in MWh/h and y-axis represents the frequency of that error as hours per year

Source: Pöyry analysis, data source: Fingrid, Finnish Energy Industries

Table 2-3 – Normal distribution characteristics, 12 hours ahead forecast error for wind

All figures in MW	2013	2015	2017
MEAN	20	31	16
σ	31	68	109
95%*	62	135	217

* 95% of the time the error is below this value

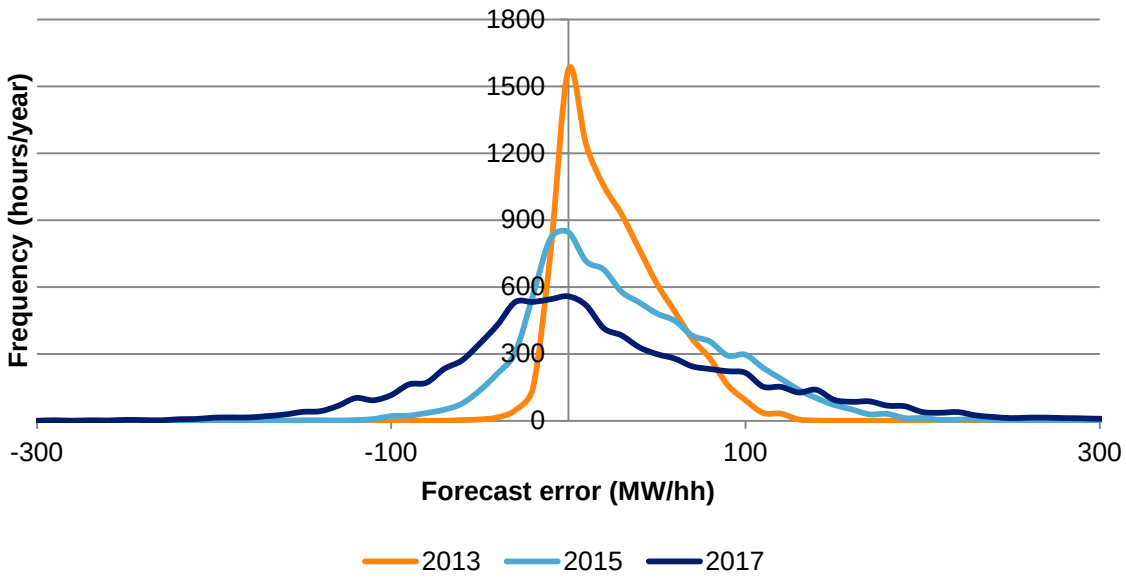
Source: Pöyry analysis, data source: Fingrid, Finnish Energy Industries

Wind – hour-ahead forecast

The trend is similar with hour-ahead forecast as with 12 hours ahead: the absolute forecast error has increased from 2013 as a result of increased wind capacity in the system. The hour-ahead forecast is more accurate than for 12 h ahead and the standard deviation is 22% smaller in 2017.

Forecast errors are less skewed compared to 12 h ahead forecast, which might be explained by different models used to forecast different time frames: short-term forecasts are typically based on statistical models instead of physical models based on weather forecasts. Table 2-4 shows the estimated normal distribution characteristics. The standard deviation in 2017 2.8-fold compared to 2013.

Figure 2-7 – Wind hour-ahead forecast error distribution



Note: x-axis represents amount of error in MWh/h and y-axis presents the frequency of that error as hours per year

Source: Pöyry analysis, data source: Fingrid, Finnish Energy

Table 2-4 – Normal distribution characteristics, wind hour-ahead forecast error

All figures in MW	2013	2015	2017
MEAN	25	32	17
σ	29	53	85
95% *	58	106	170

* 95% of the time the error is below this value

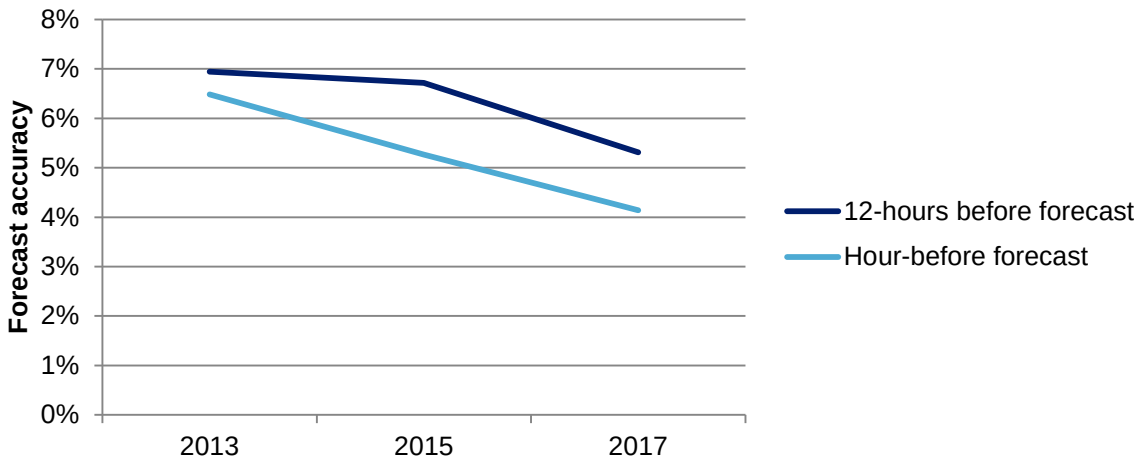
Source: Pöyry analysis, data source: Fingrid, Finnish Energy Industries

Wind forecast accuracy learning rate

Forecast accuracy describes the relative accuracy of forecasts. In case of wind power, accuracy is typically calculated as forecast error divided by installed capacity. Figure 2-8 shows the development of forecast accuracy expressed as the standard deviation of error per installed capacity. As expected, the wind forecast accuracy has noticeably improved during the analysis time frame for both hour-ahead and 12h-ahead forecasts. Typical drivers for forecasting accuracy improvement are improved methods and increased geographical diversification[11].

[11] See e.g. VTT Technology 95 – Wind power forecasting accuracy and uncertainty in Finland

Figure 2-8 – Wind forecast accuracy development



Source: Pöyry analysis, data source: Fingrid, Finnish Energy

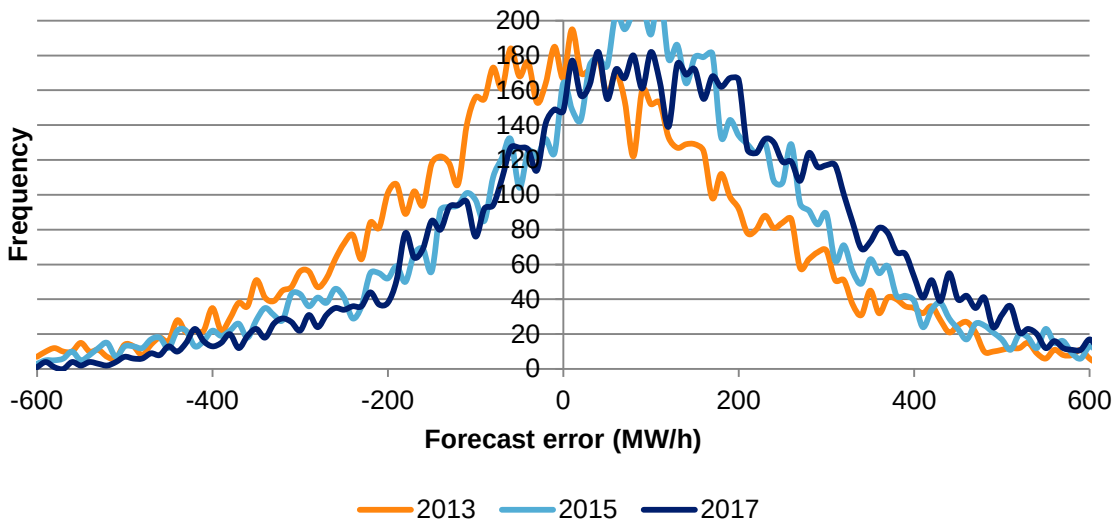
2.3.2 Historical demand forecast error analysis

Demand – day-ahead forecast error

Figure 2-9 illustrates the historical forecast errors for day-ahead demand forecast and Table 2-5 shows the normal distribution characteristics. Demand forecast error distribution is better described by a normal distribution e.g. there is no large systematic skew which was present in wind forecast error.

The demand forecast error has remained at a similar level during the analysis time period and there is no indication of trends in any direction, suggesting that the differences in distribution parameters are likely stochastic in nature and that underlying fundamentals have not changed.

Figure 2-9 – Demand day-ahead forecast error distribution



Note: x-axis represents amount of error in MWh/h and y-axis presents the frequency of that error as hours per year

Source: Pöyry analysis, data source: Fingrid

Table 2-5 – Normal distribution characteristics, demand day-ahead forecast error

	2013	2015	2017
MEAN	3	62	101
σ	246	272	217
95% *	492	544	435

* 95% of the time the error is below this value

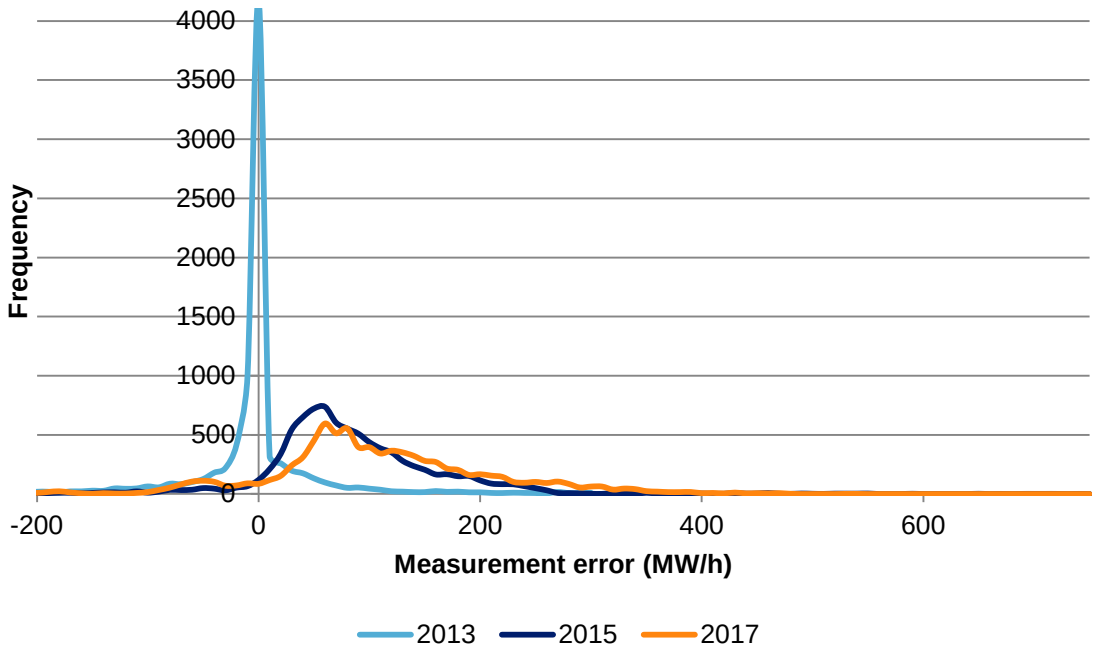
Source: Pöyry analysis, data source: Fingrid

Demand – Hour-ahead forecast error

The forecast error frequency for hour-ahead demand forecast errors is shown in Figure 2-10. Forecast error is relatively the same in 2015 and 2017, which is in line with findings for day-ahead demand forecast error distributions. Both of the forecasts are however heavily skewed to the right, indicating that there is a tendency to under forecast demand.

We find that 2013 is a clear outlier with a demand forecast that is unreasonably accurate compared to the 2015 and 2017. This unreasonable accuracy in 2013 could be explained by how the data is gathered. In the data set used, some of the missing out-turn values are estimated and it is likely that there were a significant amount of estimated values in 2013 which might have been estimated using the hour-ahead forecast. In any case, 2013 is excluded from the hour-ahead demand forecast analysis. 2014 had similar issues but 2016 was in line with 2015 and 2017 data.

Figure 2-10 – Demand hour-ahead forecast error distribution



Note: x-axis represents amount of error in MWh/h and y-axis presents the frequency of that error as hours per year

Source: Pöyry analysis, data source: Fingrid

Table 2-6 – Normal distribution characteristics, hour-ahead forecast error for demand

All figures in MW	2013	2015	2017
MEAN	-2	85	107
σ	86	112	103
95% *	**172**	**224**	**206**

* 95% of the time the error is below this value

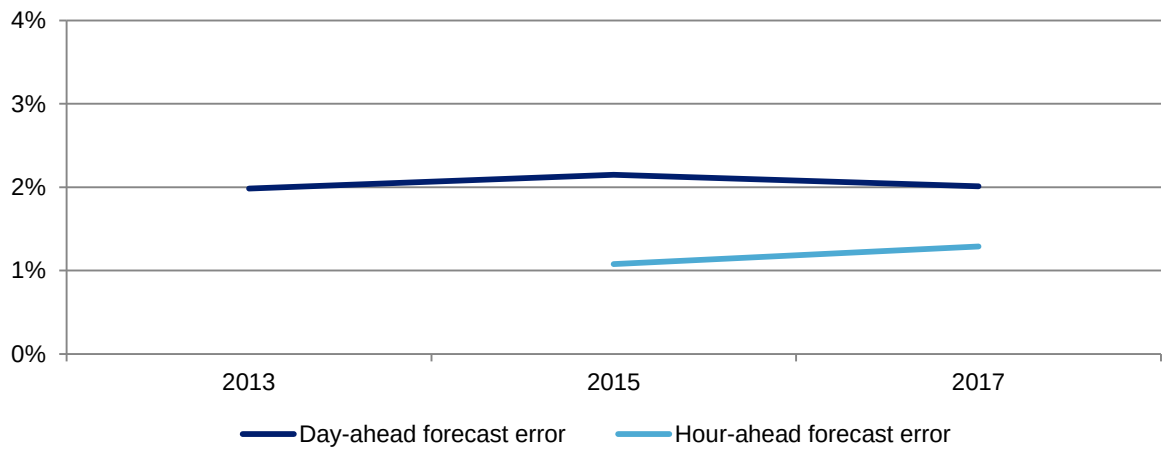
Source: Pöyry analysis, data source: Fingrid

Demand forecast accuracy learning rate

Demand forecast accuracy is defined as standard deviation of forecast error divided by out-turn (in comparison wind forecast accuracy was defined as standard deviation of forecast error divided by installed capacity). Both hour-ahead and day-ahead forecast errors have remained at the same level during the time period (2013 is omitted for hour-ahead forecast errors), which is in line with the error distributions also not changing across the years. Based on this, the forecast accuracy is not expected to develop by 2030.

Demand forecast accuracy is much better compared to wind forecast error accuracy. Calculating the hour-ahead wind forecast error accuracy in similar fashion as for demand would yield roughly an accuracy of 23% compared to less than 1.5% for hour-ahead demand forecast accuracy.

Figure 2-11 – Demand forecast accuracy development



Source: Pöyry analysis, data source: Fingrid

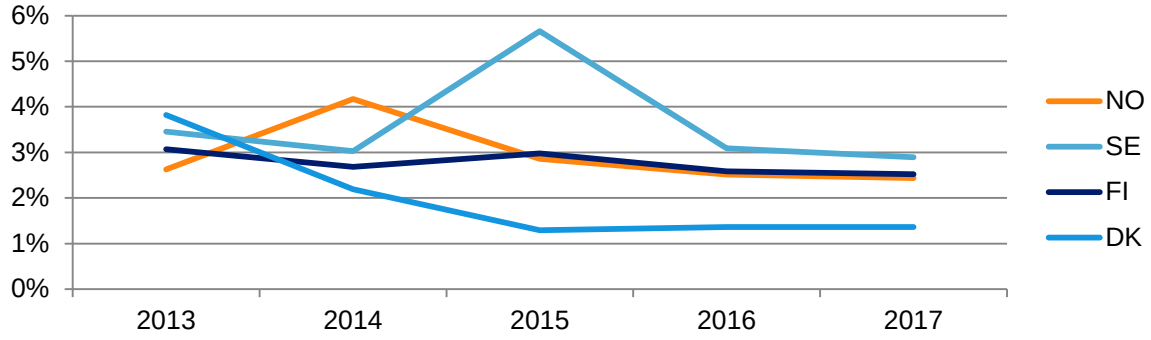
Electric vehicle (EV) impact on demand forecast accuracy

The impact of EVs on demand forecast accuracy is analysed because EVs represent a potential source of uncertainty that might reduce forecast accuracy and thus increase the demand for flexibility by 2030. The Finnish government has a target of 250,000 EVs by 2030, compared to around 1,500 in 2017. Norway is used as a benchmark for EV impact on demand forecasting as it is one of the few countries with high EV penetration with comparable statistical data available. In addition, Norway has similar demand characteristics to Finland (relatively high shares of industrial electricity consumption and residential electric heating) and the current number of EV vehicles in Norway (210,000) is close to the Finnish government target.

Figure 2-12 illustrates how demand forecasting accuracy has changed over analysis time period as RMS (root mean square) error per out-turn. All data shown is from the same source (Nordpool) to make sure figures are comparable. If EVs had had an impact on demand forecasting, Norwegian

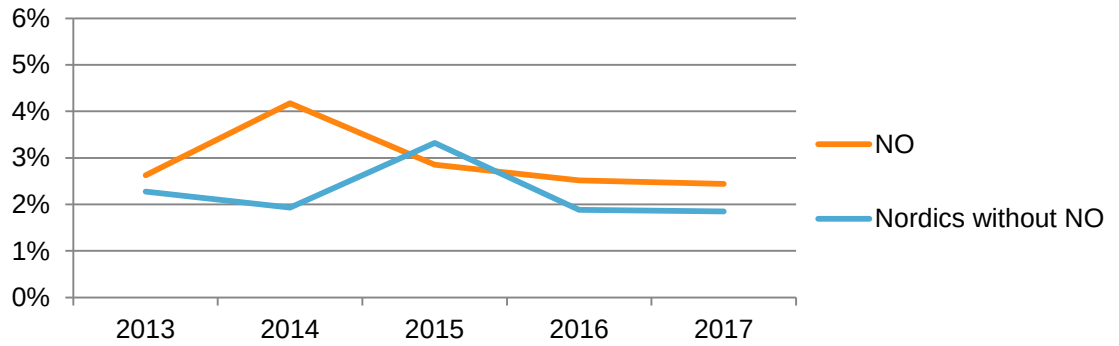
forecasting accuracy should decrease compared to other Nordic countries, which does not seem to be the case. Comparing other Nordic countries in aggregate to demand forecast accuracy in Norway (Figure 2-13) yields the same result and the forecast accuracy trends are similar. Other Nordic countries are aggregated to better illustrate the general trend. Finally, Norway does not currently regulate EV charging in any way, meaning the impact is not reduced by e.g. mandated charging profiles[12]. This suggests that EVs have not had a measurable impact on demand forecasting error in Norway and thus they are not expected to have an impact in Finland by 2030 assuming the amount of EVs will not exceed the government targets.

Figure 2-12 – Demand forecast RMS error relative to out-turn per country



Source: Pöyry analysis, data source: Nordpool

Figure 2-13 –Demand forecast RMS error relative to out-run - Norway vs. Nordics



Source: Pöyry analysis, data source: Nordpool

This analysis looks at the aggregate impact and the situation might be different on more granular level, e.g. when looking at demand forecasting in specific network areas. However as this report looks at flexibility at a system level, we consider this review sufficient.

2.3.3 Total historical forecast error

Demand for flexibility created by total forecast error is the combination of wind and demand forecast errors. Hour-ahead forecast errors are directly comparable but the 12h-ahead forecast error for wind and day-ahead forecast error for demand need to be adjusted. These were analysed in different time horizons because of data availability: day-ahead forecasts were not available for wind power for the full analysis time frame (2013–2017). Adjustment was done using 2017 data as

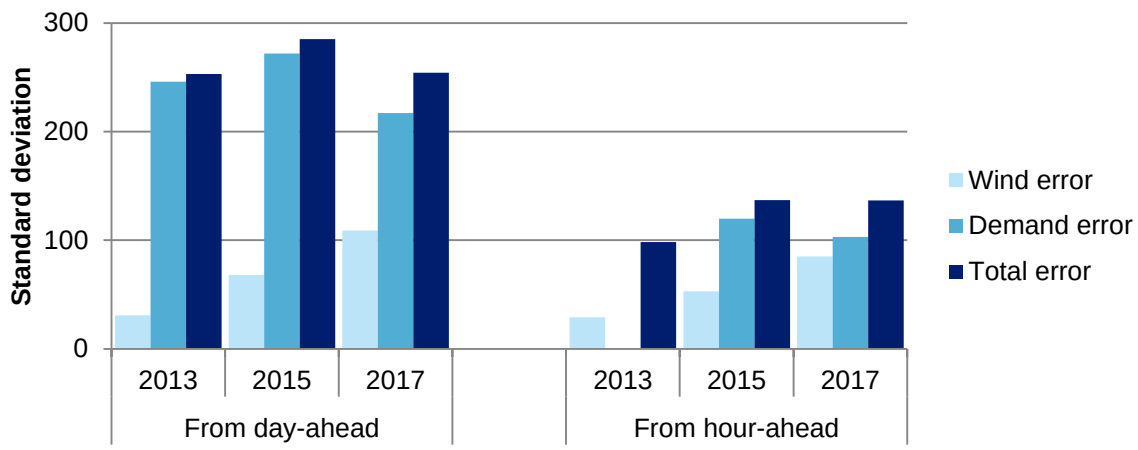
[12] Source: https://www.nve.no/om-nve/regelverk/lov-og-forskriftsendringer-pa-horing-ikke-konsesjonssaker/horing-forslag-til-endringer-i-forskrift-om-kontroll-av-nettvirksomhet-tariffer-avsluttet/

both day-ahead and 12h-ahead wind forecasts were available for that year. The difference between the standard deviations is roughly 0.7 percentage points which was used to scale the 12h-ahead wind forecast error.

Total forecast error from 2013 to 2017 is shown in Figure 2-13 and we make the following observations:

- In all of the analysed years and forecast horizons, the total forecast error is less than the direct sum of the components (wind and demand forecast error), meaning that the two forecast errors compensate each other to some extent (Table 2-7). However, demand forecast errors are the major component of total forecast error.
- The standard deviation of wind forecast errors has been growing over the period due increasing wind capacity.
- The impact of the negative correlation between wind and demand forecast errors is less prominent in hour-ahead forecast.

Figure 2-14 – Standard deviation of different forecast errors



Source: Pöyry analysis, data source: Fingrid, Nordpool

Table 2-7 – Correlation between forecast errors

	Day-ahead forecast	Hour-ahead forecast
2013	-16%	N/A
2015	-6%	-4%
2017	**-9%**	**-6%**

Source: Pöyry analysis, data source: Fingrid, Nordpool

Forecast error for 15 minutes interval

Forecast error for 15 minutes interval (that is, not 15 minute forecast, but forecast error during 15 minute window) is analysed to see if 15 minutes resolution would have impact on the forecast error. Because of data quality issues (high resolution data provided by Fingrid's open data platform is in part incomplete) comparison was done using German day-ahead demand and wind production forecasts and out-turns. Table 2-8 shows the comparison between the 1-hour and 15-minutes resolution forecast errors. Both the mean and the deviation are nearly identical between the two forecast errors indicating that there is no difference between the two.

Table 2-8 – Comparison of 15 minute and 1 hour resolution wind and demand forecast errors (2017)

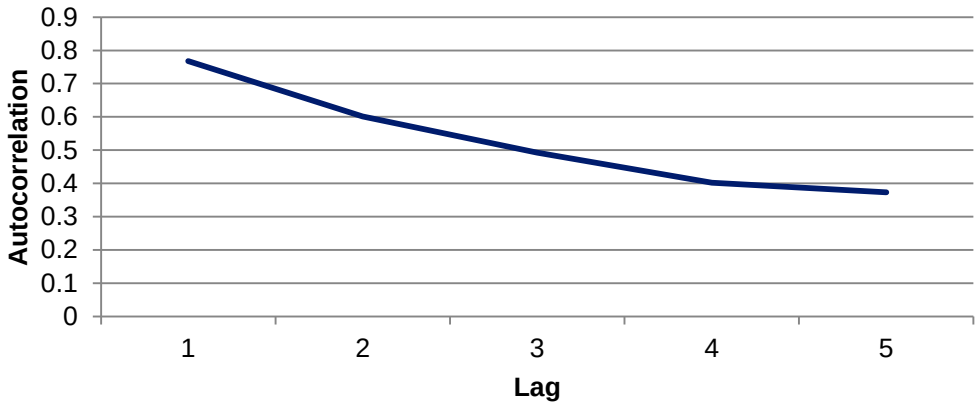
	Demand forecast error		Wind forecast error	
	Mean	**Standard deviation**	**Mean**	**Standard deviation**
15 minute resolution	-450 MW	1960 MW	150 MW	1220 MW
1 hour resolution	-450 MW	1920 MW	150 MW	1210 MW

Source: Pöyry analysis, data source: ENTSO-E Transparency platform

Probability of forecast error continuing

Figure 2-15 illustrates autocorrelation[13] of total hour-ahead forecast error (averaged across 2013, 15 and 17) with different time lag. It shows that there is correlation between two consecutive hours, with the correlation decreasing with the difference of hours being compared. It indicates that if there is error present, it is likely that there will be similar error in the following hour. The autocorrelation however varies fairly significantly between the years, and because of this it is fairly difficult to make concrete conclusions.

Figure 2-15 – Autocorrelation of total hour-ahead forecast error with different time lags (lag in hours)



Source: Pöyry analysis, data source: Fingrid

2.3.4 Historical hourly swing

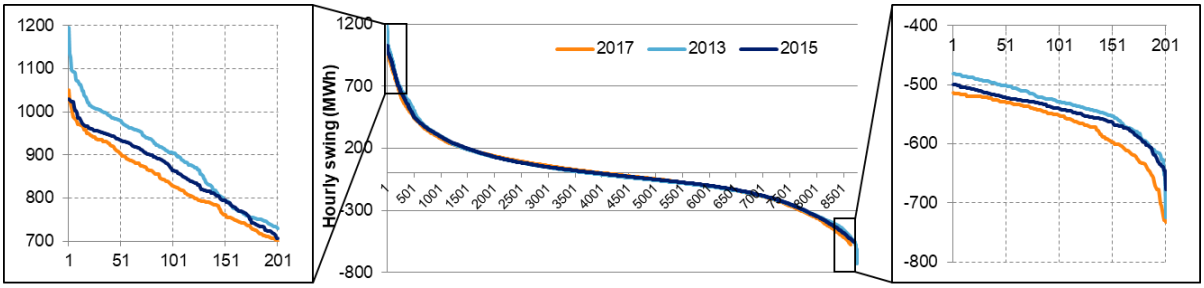
Figure 2-16 illustrates how the hourly swing has developed over the analysis time period. There has not been a significant change in the hourly swing in general; suggesting that increased wind power capacity has not had a large impact on hourly swing in Finland.

The largest positive swings are higher in 2013 than in 2017, even though wind power capacity has increased substantially from 2013. Based on how the hourly swing is defined, wind production may

[13] Describes how time series values correlate with themselves. E.g. if the error is present in a certain hour, how likely it is that the following hour will have a similar error.

actually compensate for demand swings depending on the direction of demand and wind production swings. For example, during a positive demand swing, positive wind production swing (production higher in the following hour) decreases the total hourly swing. Situation might be different looking at smaller part of the network, but this analysis is out of the scope of this report.

Figure 2-16 – Hourly swing duration curves



Hourly swing is defined as difference between demand minus RES generation over two consecutive hours:

$$Hourly\ swing = (Demand - RES)_t - (Demand - RES)_{t-1}$$

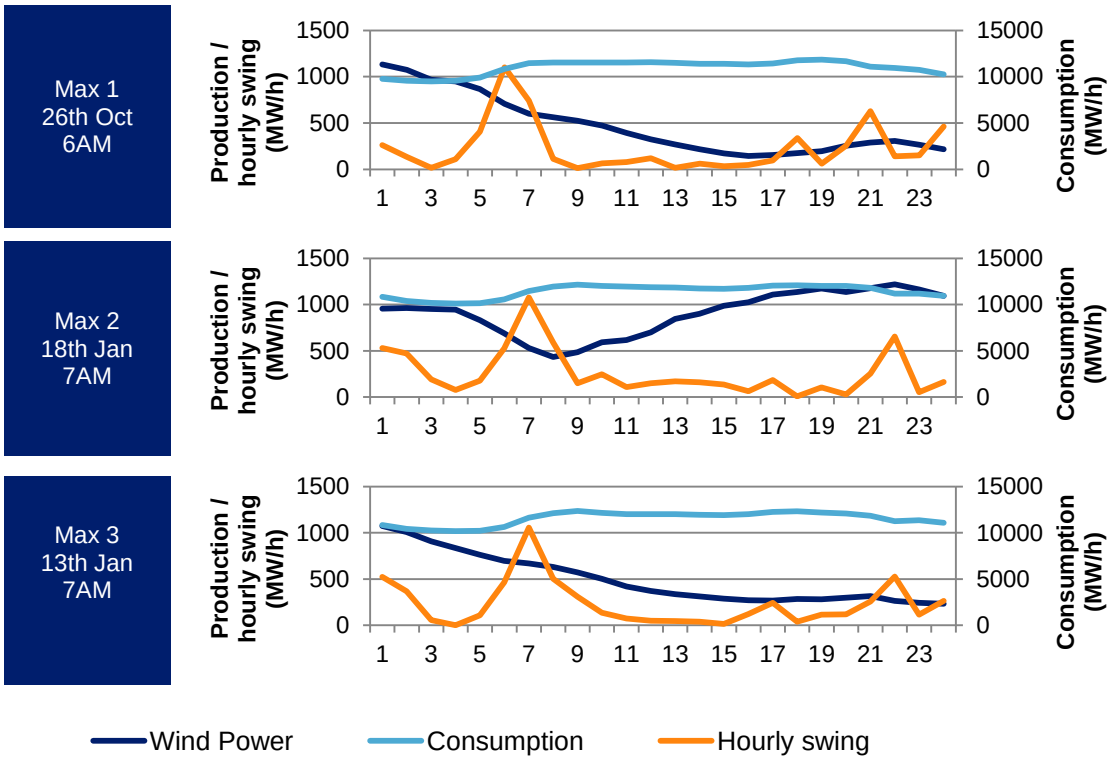
Source: Pöyry analysis, data source: Fingrid

Timing of the largest hourly swings

The historical analysis suggests that the primary driver behind historical hourly swing is demand. Data from 2017 provides supporting evidence: 100 largest swings in 2017 took place during the morning ramp hours, either 6 am – 7 am or 7 am – 8 am, which means that currently those hours contribute to the largest swing values (left side of Figure 2-16).

Figure 2-17 shows the hourly profile of three days with highest hourly swings in 2017. In all of the cases the demand swing has been large as is typical for a morning ramp, accompanied by decreasing wind production. In these three cases 85% to 97% of the swing came from increase in demand meaning that while wind decrease did contribute, the main driver was the demand swing.

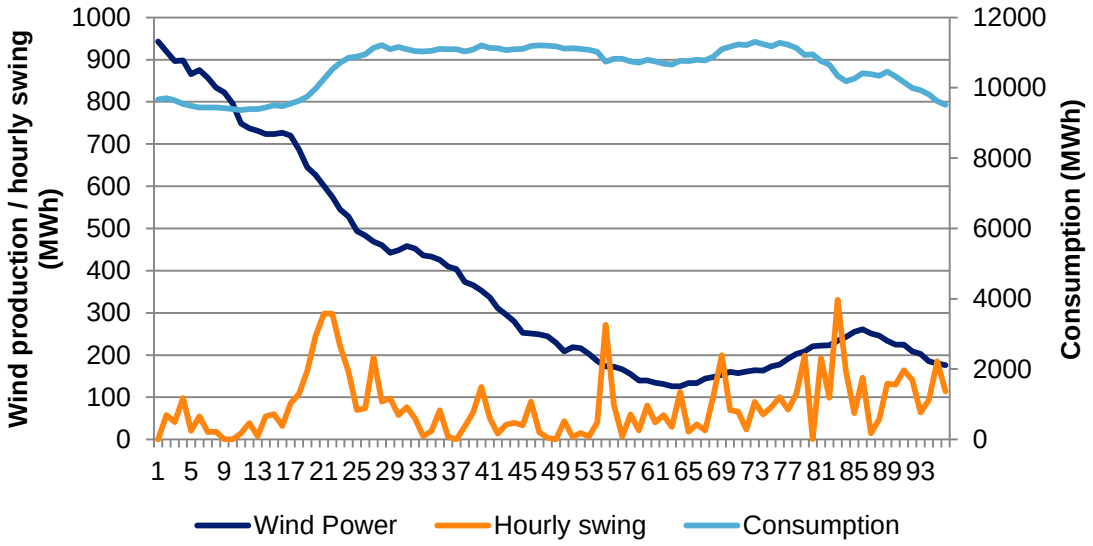
Figure 2-17 – Three largest hourly swing (2017)



Source: Pöyry analysis, data source: Fingrid

Figure 2-18 illustrates the day with maximum hourly swing in 2017 (shown in previous figure) in 15 minute resolution and with 15 minute swing. Interestingly, in addition to morning ramp, there are two other large swings that are in 15 minute resolution equal to it.

Figure 2-18 – 26th Oct hourly swing in 15 minute resolution

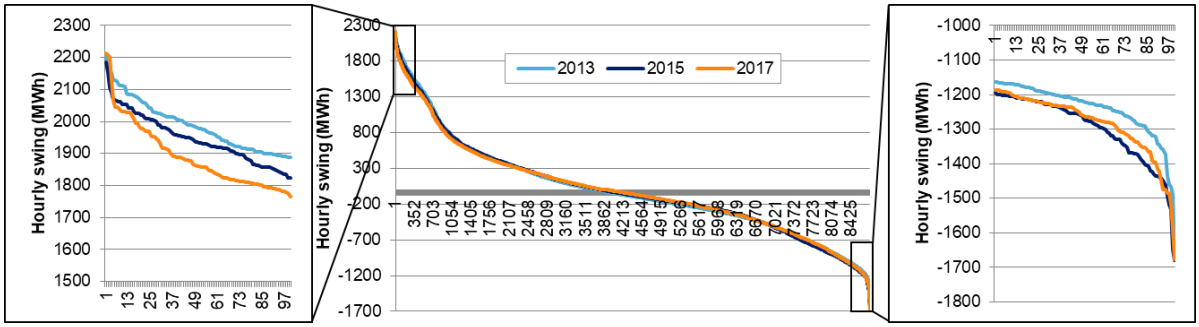


Source: Pöyry analysis, data source: Fingrid

Three-hour swing

Three-hour swings are calculated in the same way as hourly swings, but instead two consecutive hours, hours with three hour gap are compared. It represents a similar type of demand for flexibility as the hourly swing but with a longer time horizon (e.g. a full morning ramp in demand). Comparing the three hour swings yields similar result to hourly swings: overall the differences are fairly small and increasing wind power has not impacted the swings significantly suggesting again that the primary driver behind the historical swing is demand.

Figure 2-19 – Three hour swing duration curve



Three hour swing is defined as difference between demand minus RES generation over three hour gap:
$$\text{Three } hour\ swing = (Demand - RES)_t - (Demand - RES)_{t-3h}$$

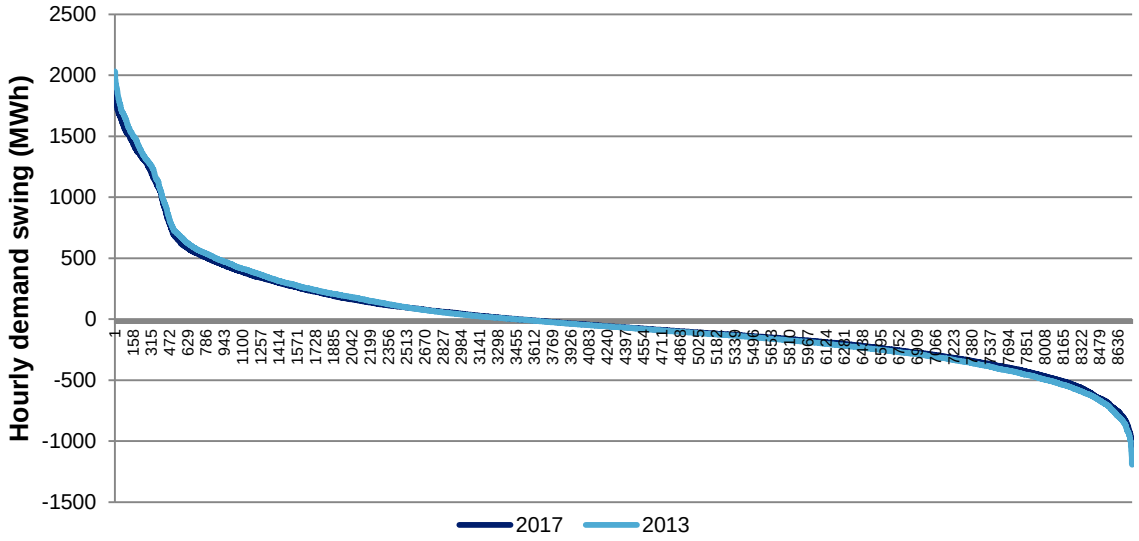
Source: Pöyry analysis, data source: Fingrid

Impact of EVs to hourly swing in Norway

EVs (electric vehicles) also represent a potential source of additional flexibility demand if they increase hourly swing. For example EV owners starting charging in the afternoon when returning from work could create large demand spikes. Similar to demand forecast error, Norway is analysed as a case example to see whether EVs have had any impact on demand swing and whether they would be expected to impact demand swing in Finland as well. Here we only look at demand swing, without netting RES (subtracting variable renewables) generation, because only the impact of EVs is of interest. As Figure 2-20 shows, EVs have not had any measurable impact on hourly swing in Norway between 2013 and 2017 on system level. Situation might be different on distribution network level, but that analysis is out of the scope of this report. Y-axis denotes the amount of swing and X-axis the order. At the same time, the number of registered EVs and hybrids has increased more than 10-fold from 20k in 2013 to 210k in 2017.

Based on this and the fact that historically there have been no regulations aiming to steer charging behaviour in Norway, we assume that EVs are not likely to have a significant impact on demand swing in Finland.

Figure 2-20 – Hourly demand swing in Norway 2013 vs. 2017



Source: Nordpool; Elbilforening (electric car association in Norway): Statistics Norway

2.4 Future demand for flexibility

This section looks at future demand for flexibility and is presented in the following sections: First development of wind and demand forecast errors are estimated separately. The analysis is based on historical data and expected wind production and demand development. Next the wind and demand forecast errors for different time horizons are combined to estimate total forecast errors. Finally we analyse the expected development of hourly swing until 2030

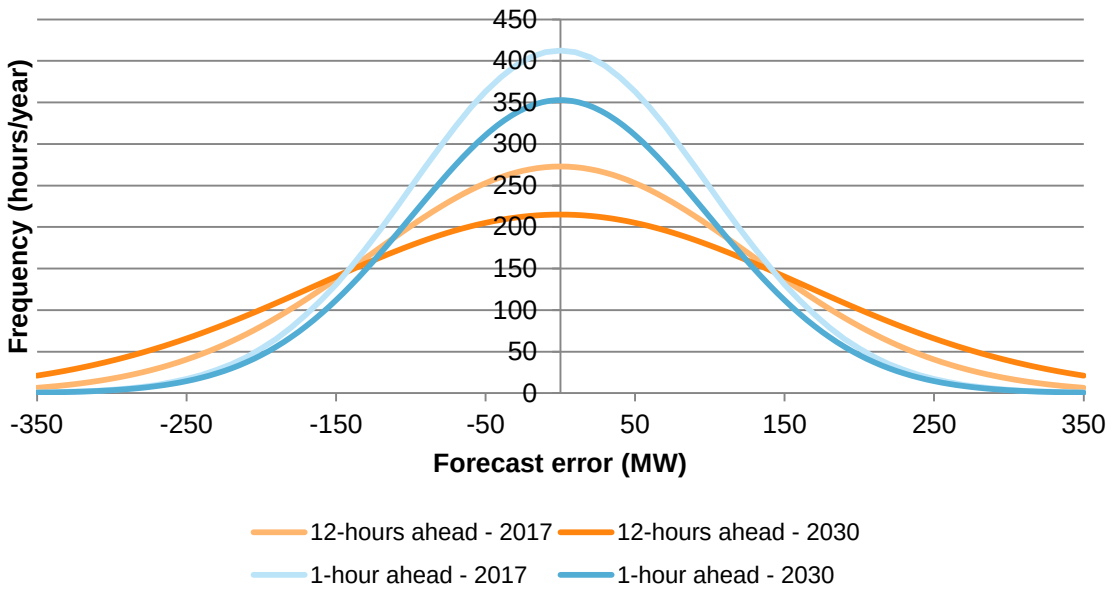
2.4.1 Wind forecast error in 2030

Wind forecast error development is based on expected wind capacity development, which is estimated to be 3.4 GW in 2030, and historical forecast accuracy learning rate shown in section 2.2. Error deviation is estimated by scaling the error based on the expected amount of wind capacity and adjusting it down based on the learning rate. The learning rate was assumed to follow linear trend and it was adjusted by excluding 2013 data because there was only little wind capacity during that year, which could lead to over estimating the learning rate.

Figure 2-21 illustrates how the wind forecast error is expected to develop by 2030 with 2017 shown as a comparator. Normal distribution characteristics are shown in Table 2-9. The error will increase from the current level because of new wind capacity. As a result, there will be more hours with larger forecast errors and so the error frequency distribution becomes flatter and wider. However, because of the learning rate, the absolute increase in forecasting error is not proportional to increase in wind capacity.

The forecast error is assumed to be unbiased, as it is difficult to assess if the historical forecast error bias is caused by inherent randomness of the forecast error or by e.g. forecast models used. In the latter case assuming the current bias to remain until 2030 would mean that we would need to assume the forecast models and methods would remain the same, which is a justifiable assumption.

Figure 2-21 – Wind forecast error distributions



Note: X-axis represents amount of error in MWh/h and Y-axis presents the frequency of that error as hours per year

Source: Pöyry analysis, data source: Fingrid

Table 2-9 – Normal distribution characteristics, wind forecast errors

	2030 day-ahead	2030 t+1h
σ	138 MW	115 MW
95%*	276 MW	230 MW

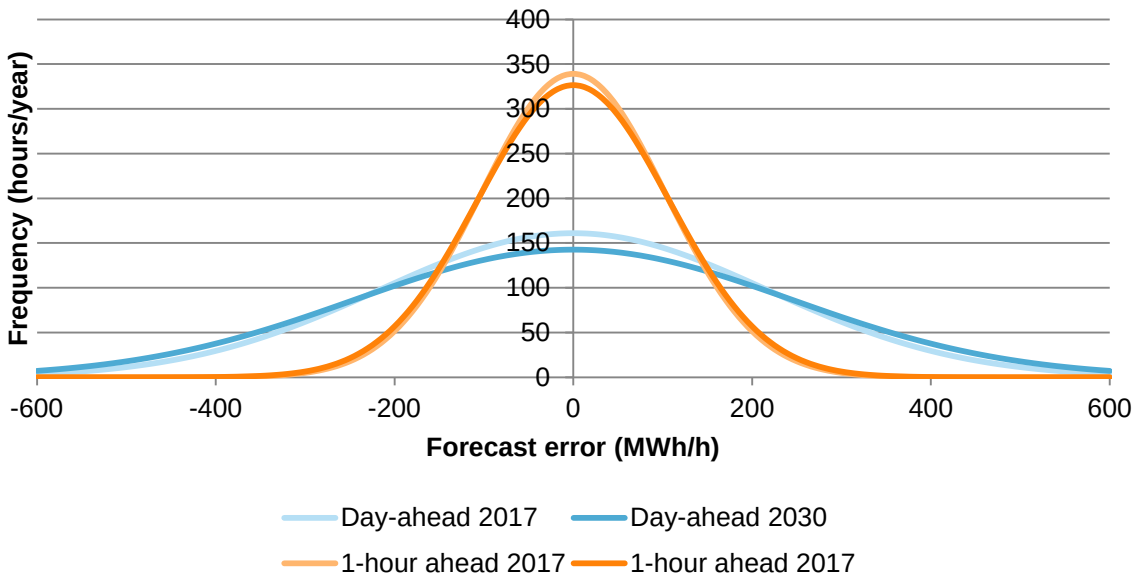
* 95% of the time the error is below this value

Source: Pöyry analysis, data source: Fingrid

2.4.2 Demand forecast error in 2030

Demand forecast error is expected to remain largely at the current level (Figure 2-22). Our scenario assumption is that electricity demand is not expected to grow significantly from the current level. Based on historical analysis the accuracy is not expected to improve, which makes sense as demand forecasting has been done for a long period of time and the accuracy is already very high. Some improvements might be possible through e.g. automation but a conservative estimate of no change is preferred. In addition EVs are not expected to have a measurable impact as per the historical analysis shown in the previous section.

Figure 2-22 – Demand forecast error distributions



Note: X-axis represents amount of error in MW/h and Y-axis presents the frequency of that error as hours per year

Source: Pöyry analysis, data source: Fingrid

Table 2-10 – Normal distribution characteristics, demand forecast errors

	2030 day-ahead	2030 t+1h
σ	245 MW	107 MW
95%*	490 MW	214 MW

* 95% of the time the error is below this value

Source: Pöyry analysis, data source: Fingrid

2.4.3 Total forecast error in 2030

The two forecast errors (wind and demand) for 2030 were combined using the formula:

$$VAR(A,B) = VAR(A) + VAR(B) + COV(A,B)$$

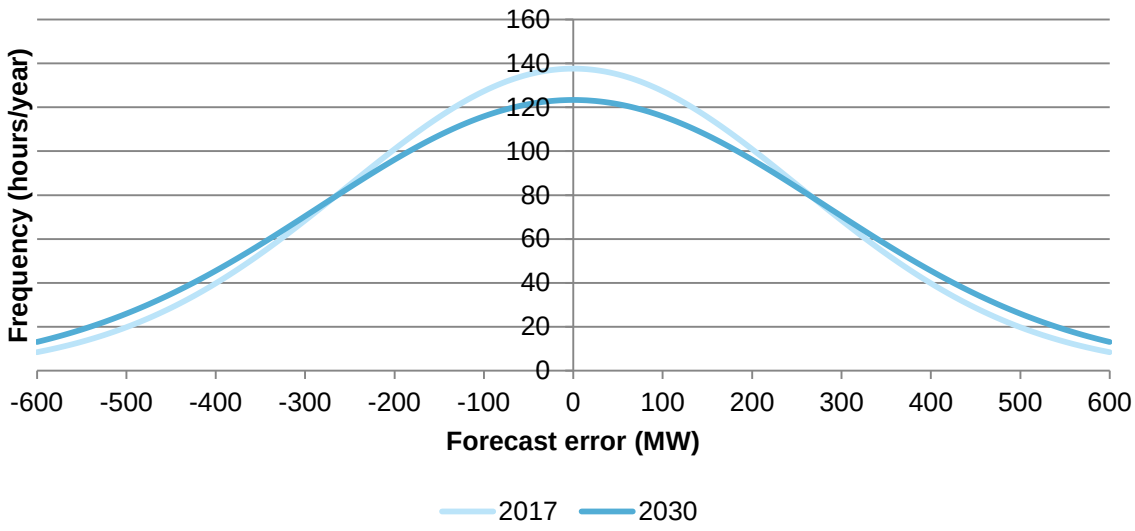
Where VAR denotes the variance, COV denotes covariance between two random variables and A & B are random variables, in this case wind and demand forecast errors. Covariance was calculated based on historical values.

Total day-ahead forecast error in 2030

Figure 2-23 illustrates the total forecast error for day-ahead forecast. The total error is expected to increase moderately from 2017 levels: standard deviation is 11% higher in 2030 compared to 2017. The increase is limited by the combined effect of wind power forecast learning rate and the negative correlation between wind and demand forecast errors. The errors are negatively correlated because wind production and demand both have a positive correlation with temperature.

Table 2-11 shows the normal distribution characteristics of the total forecast error. Maximum demand for flexibility due to day-ahead forecast errors is estimated to be roughly 1.1 GW (99.99% probability range, which corresponds to roughly 1 hour in two years). This means that the forecast error is below 1.1 GW 99.99% of the time.

Figure 2-23 – Total day-ahead forecast error distribution



Note: X-axis represents amount of error in MW/h and Y-axis presents the frequency of that error as hours per year

Source: Pöyry analysis, data source: Fingrid

Table 2-11 – Normal distribution characteristics, total day-ahead forecast error

Deviation multiple	Probability range	Deviation
σ	63%	285 MW
2σ	95%	565 MW
3σ	99.7%	850 MW
4σ	99.99%*	1,135 MW

* Roughly 0.55 hours per year

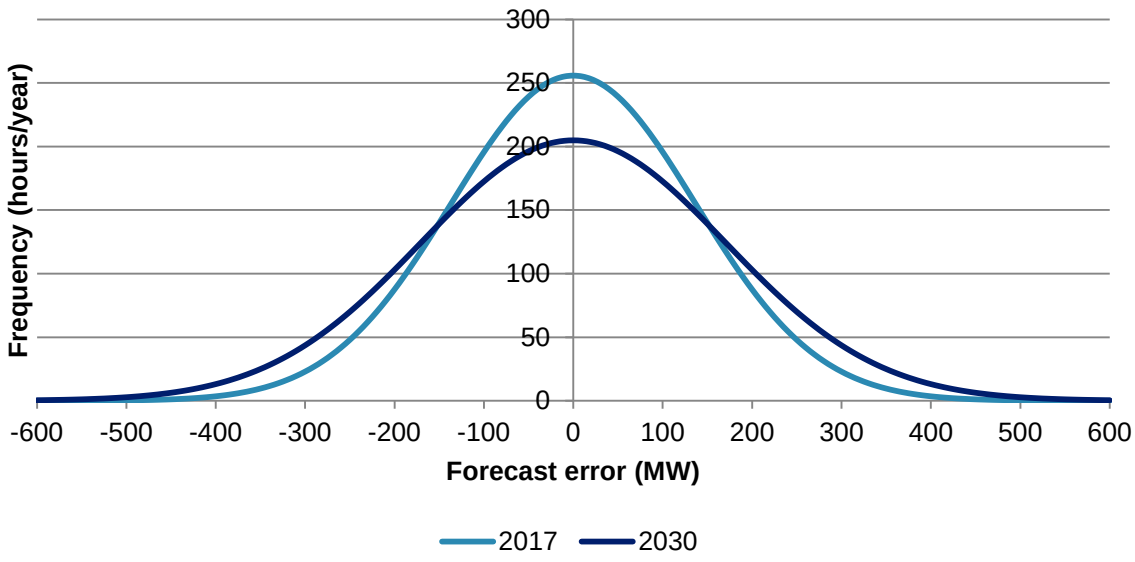
Source: Pöyry analysis, data source: Fingrid

Total hour-ahead forecast error in 2030

Similar development is expected for hour-ahead forecast error (Figure 2-24). The standard deviation increases by roughly 25 % from 2017 level. This is more than the corresponding day-ahead forecast error and is caused by the lower level of correlation between the two forecast errors. One possible explanation of the difference to day-ahead forecast errors (both forecasts were done by Fingrid) could be that different forecast methods and models are used to make hour-ahead forecasts. For example, hour-ahead forecasts use out-turns of previous hours instead of relying solely on weather forecast data like day-ahead forecasts.

The maximum demand for flexibility from hour-ahead forecast errors is estimated to be 0.7 GW, which is enough to cover 99.99% of situations. Normal distribution characteristics are shown in Table 2-12.

Figure 2-24 – Total hour-ahead forecast error distribution



Note: X-axis represents amount of error in MW/h and Y-axis presents the frequency of that error as hours per year

Source: Pöyry analysis, data source: Fingrid

Table 2-12 – Normal distribution characteristics, total hour ahead error distribution

Deviation multiple	Probability range	Deviation
σ	63%	175 MW
2σ	95%	345 MW
3σ	99.7%	520 MW
4σ	99.99%*	690 MW

* Roughly 0.55 hours per year

Pöyry analysis, data source: Fingrid

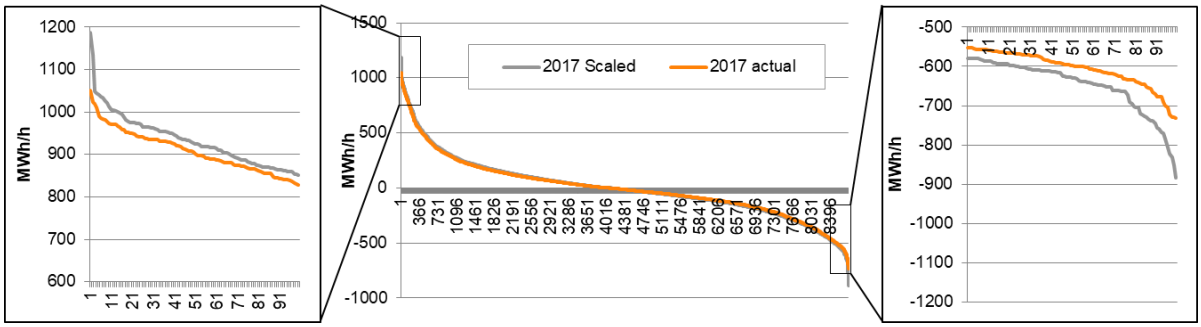
2.4.4 Hourly swing in 2030

Hourly swing for 2030 was calculated by scaling 2017 wind production according to expected capacity development by 2030. This is an approximation because in reality geographical diversification would likely slightly smooth out the production, reducing the swings and higher load factor of new wind turbines might slightly increase the swings. Overall the two effects compensate for each other so the approximation is considered sufficient. The following observations can be made:

- Hourly swing is expected to grow from current levels, but not proportionally to increased wind capacity. Furthermore, hourly swing is not estimated to change significantly from 2017 levels on an average basis.
- There is a noticeable change in the largest hourly swings, positive and negative. Results indicate an average increase of around 24MW to 26MW for the 100 largest values and a higher increase, of around 140 MW, between the maximum values.

- Demand will continue to be the primary driver behind the large hourly swings. Simulations show that wind year does not correlate with overall amplitude of the swings in a certain year (18 different weather years simulated for 2030).

Figure 2-25 – Hourly swing duration curve



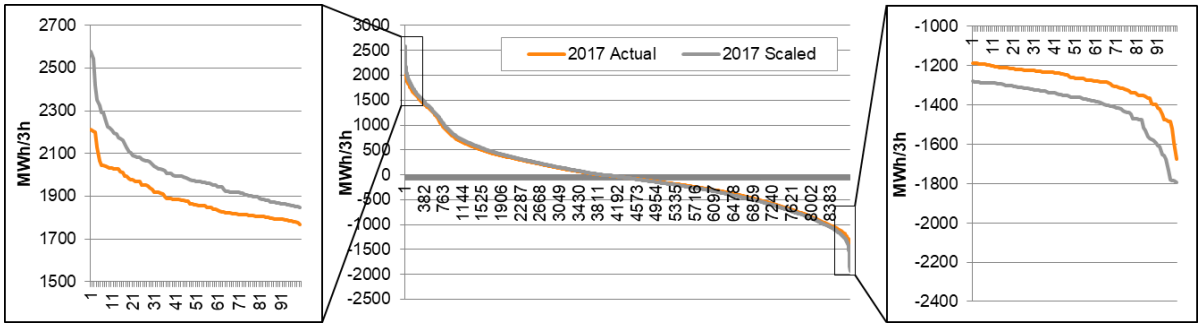
Hourly swing is defined as difference between demand minus RES generation over two consecutive hours:
$$\text{Hour swing} = (Demand - RES)_t - (Demand - RES)_{t-h}$$

Source: Pöyry analysis, data source: Fingrid

Three hour swing in 2030

The difference between current situation and 2030 is more noticeable when looking at three hour swings. The difference at peak is around 300 MW more than in 2017 (actual vs. scaled).

Figure 2-26 – Three hour swing duration curve



Three hour swing is defined as difference between demand minus RES generation over three hour gap:
$$\text{Three hour swing} = (Demand - RES)_t - (Demand - RES)_{t-3h}$$

Source: Pöyry analysis, data source: Fingrid

2.4.5 Summary of results

Demand of flexibility through expected and unexpected changes in demand and renewable energy production is expected to increase by 2030 but only moderately. Forecasted changes from one hour to the next, 'hourly swing', in demand net wind production are expected to remain to be driven by demand also in 2030. Wind forecast error is expected to grow from the current level. However, the growth is to some degree compensated by increased forecast accuracy so the growth in forecast error is not proportional to growth in wind power capacity. Growth in total forecasting error is in addition compensated by negative correlation between wind and demand forecasting error: the two errors compensate each other. The results are summarised in Table 2-13, separately for the development of total forecast error and hourly swing (see Figure 2-4 on how the interpret the results).

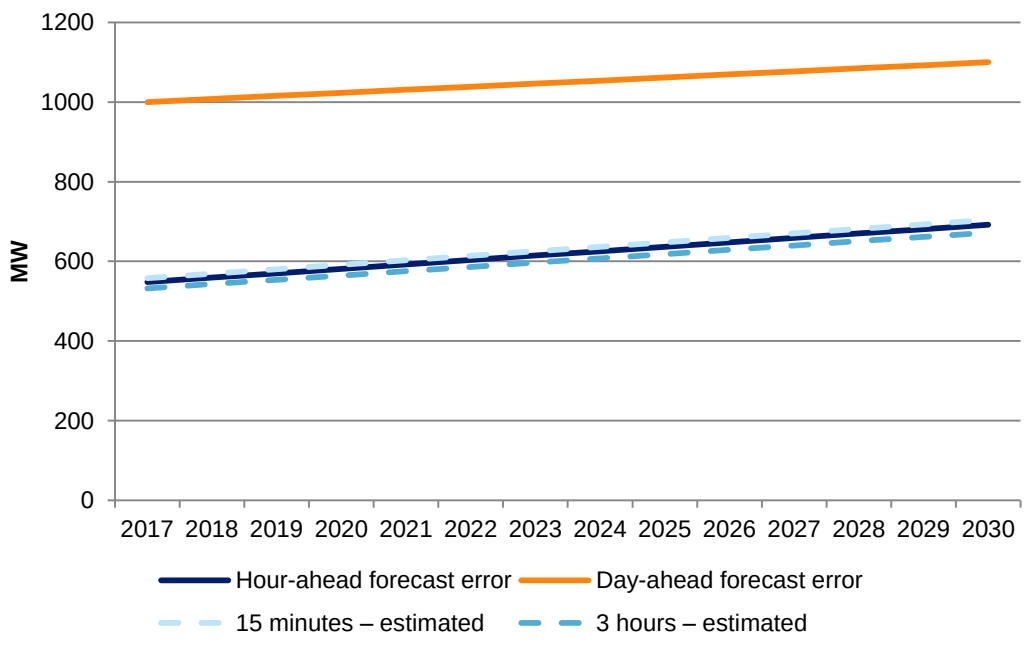
Figure 2-27 illustrates how the 4σ total forecast error deviation will develop between 2017 and 2030. It also shows estimated values for 15-min and 3-hour forecast error deviation based on hour ahead forecast. They show how much flexible capacity is required over a 15 minute and 3 hour period. Estimate is based on the same German forecast data than shown in Section 2.3.3. Both of the estimates are nearly identical with the one hour forecast error, indicating that there is not much of a difference. Figure 2-28 illustrates how maximum values of hourly swing and three hour swing develop between 2017 and 2030. Two values are shown for three hour swing: The actual swing and the three hour swing divided by three which indicates what the average hourly change within three hour swing is. Due to issues with data consistency we have not been able to analyse the distribution and confidence levels of the 15 min swings.

Table 2-13 – Summary of flexibility demand in 2030

	Total forecast error				Hourly swing	
%	GW				GW	
	DAM		Hour-ahead		1h swing	
	2017	2030	2017	2030	2017	2030
68% (σ)	0.3	0.3	0.15	0.2	0.2	0.2
95% (2σ)	0.5	0.6	0.3	0.3	0.55	0.6
99.7% (3σ)	0.8	0.9	0.4	0.5	0.9	0.9
99.99% (4σ)	1.0	1.1	0.6	0.7	1.1	1.2

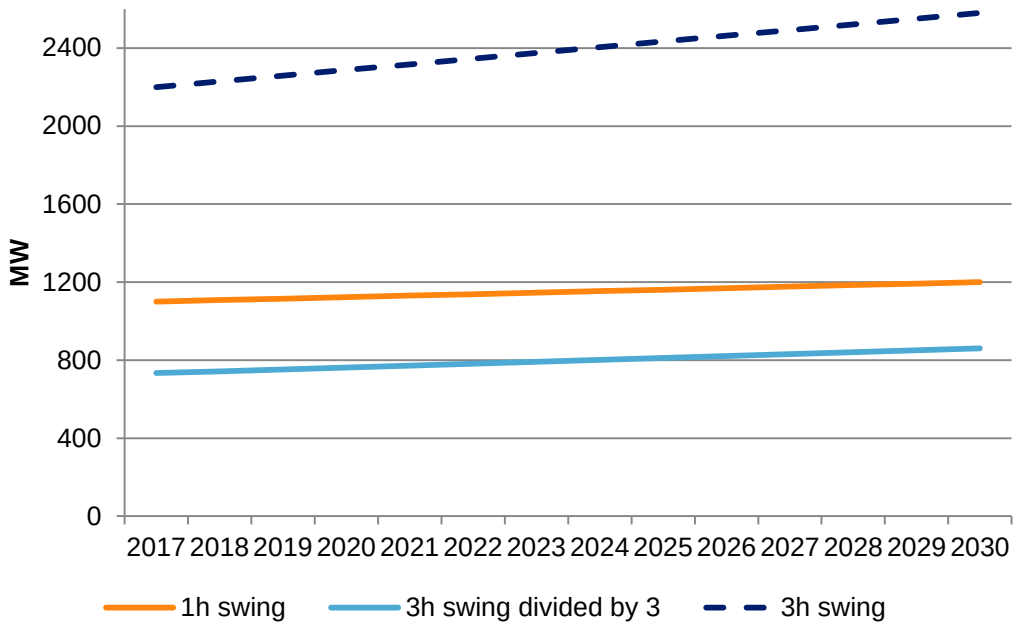
Source: Pöyry analysis

Figure 2-27 – Development of 4σ deviation between 2017 and 2030



Source: Pöyry analysis

Figure 2-28 – Development of maximum value of hourly and three hour swing



3. SUPPLY OF FLEXIBILITY

In this section we present our analysis on the supply of flexibility until 2030. The section is structured as follows:

- Section 3.1 defines flexibility in this study.
- Section 3.2 describes the approach used in this study to evaluate the supply of flexibility.
  - Section 3.2.1 introduces the evaluation method for flexibility.
- Section 3.3 analyses historical production data to provide benchmarks for flexibility.
- Section 3.4 focuses on capabilities of demand-side flexibility.
  - Section 4.1 dives deeper into potential for residential flexibility, especially from flexible heating.
- Section 3.5 analyses the total supply of flexibility from all sources until 2030.

3.1 Defining supply of flexibility

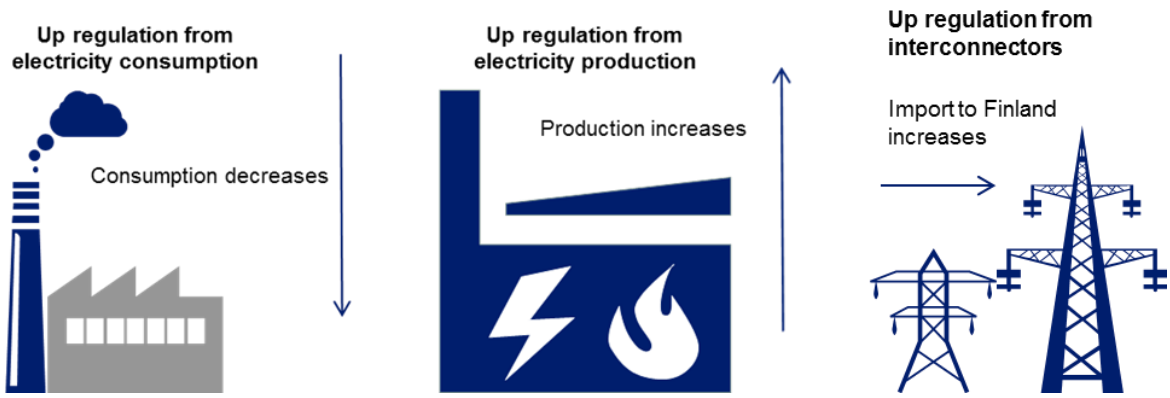
Supply of flexibility[14] is defined as the potential to increase or decrease production or consumption of electricity. However, defining flexibility in more concrete terms is not simple.

Three technical dimensions of flexibility are considered in this study:

- Direction of flexibility – up-regulation to cover a shortfall or down-regulation to compensate for a surplus
- Source of supply – production, demand-side flexibility, interconnectors or energy storage
- Duration of flexibility – how long the activated flexibility is available for the market.

The direction of flexibility is opposite for production and consumption: when electricity production is providing up-regulation, electricity production is increased, but when electricity consumption provides up-regulation, electricity consumption is reduced. This is opposite for down-regulation. Flexibility direction is illustrated in Figure 3-1.

Figure 3-1 – Flexibility direction for production and consumption



[14] Available flexibility is referred to as flexibility potential, except when specifically discussing activated flexibility. When no clear distinction is made between these two cases, 'flexibility' is used.

Activation time and duration

Supply of flexibility has two time dimensions; the activation time and duration. As most of the historical data and our electricity market modelling are available in 1 h resolution, the starting point for evaluating the duration of available flexibility is one hour. Activation time is defined as the time it takes for the source of flexibility to provide the offered amount of flexibility from the moment of activation. While we are not using a strict definition for the activation time, the analysis is based on changes in production and demand within an hour (historical hourly profiles) and 15 minutes[15].

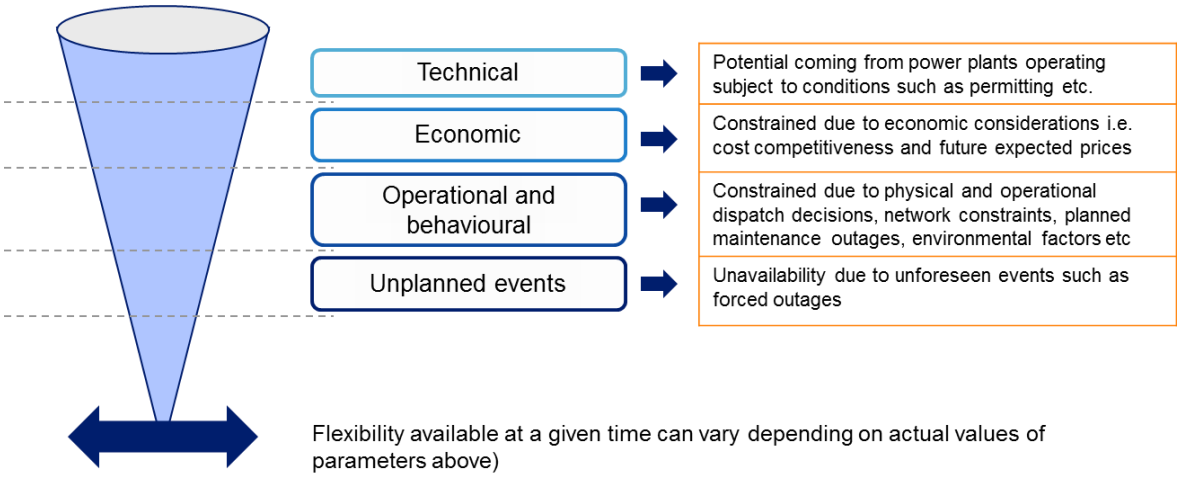
When up- or down-regulation is activated, electricity production will ramp to a new level. The capabilities of a power plant to stay at that level do not vary significantly within a few hours. Hence, we have assumed in our methodology that up- and down-regulation potential is the same for 15 min, 1 h and 3 h durations.

According to the stakeholder interviews (see section 3.4), industrial demand-side response is typically technically capable of offering flexibility for a few hours. A similar finding was made in an earlier study on industrial demand-side response by VTT, which concluded that with short-term notice periods of 0-2 h, the technical flexibility potential is the same for 0-3 h durations.[16]

3.2 Approach

Availability of flexibility is dependent on technical, economic, operational and behavioural constraints as well as unplanned events. This study focuses on assessing the **technical** aspect of supply of flexibility – availability in operational timescales is also driven by other factors (see Figure 3-2).

Figure 3-2 – Flexibility constraints



Source: Pöyry

3.2.1 Evaluating the supply of flexibility

Figure 3-3 shows a schematic of the approach to estimate the supply of flexibility in this study. In summary:

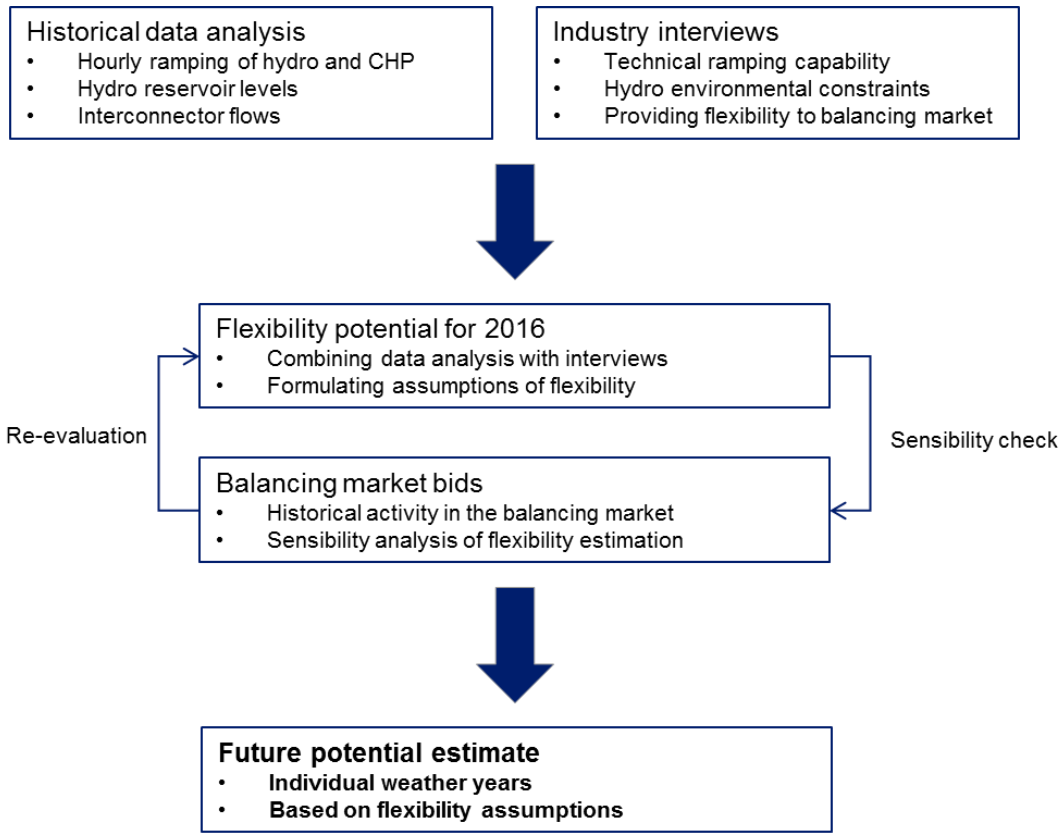
- historical data analysis based on hourly electricity production and interconnector data;
- interviews with power plant operators and industrial consumers from different segments;

[15] Balancing market bids have to be capable of providing 100% of the bid within 15 minutes.

[16] VTT. Sähkön kysyntäjouston potentiaalikartoitus teollisuudessa. 2005.

- aggregated balancing market bid data to give one estimation for the overall volumes and profile for supply of flexibility; checking that the estimate is not significantly below or above the bid volumes; and
- results from Pöyry's electricity market model, utilising the findings from the previous steps for each future year evaluated.

Figure 3-3 – Schematic of approach to estimating flexibility potential



3.3 Historical data analysis for production flexibility

3.3.1 Initial assumptions

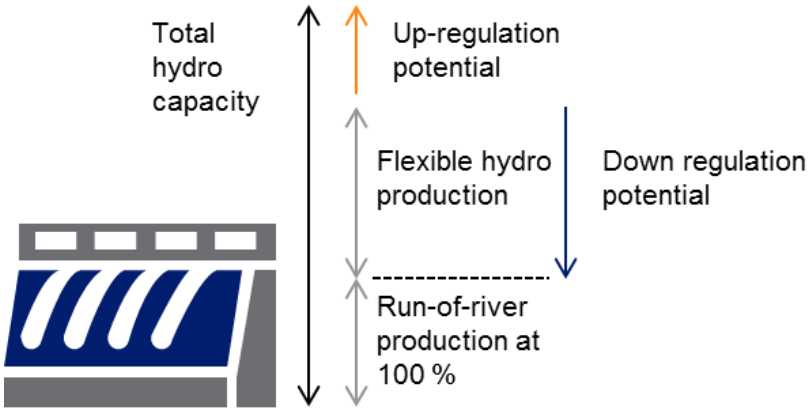
The supply of flexibility analysis focuses on hydro production, combined heat and power (CHP), demand side response and interconnection, which are the main sources of flexibility in Finland. This was based on Pöyry information and industry interviews.

Wind power is technically capable of providing frequency response and down-regulation (also up-regulation, if production is first curtailed). We have however not included the supply of flexibility from wind power plants in our scenario as a conservative assumption. Nuclear power can be designed to provide flexibility, but as Finnish nuclear plants are designed to provide stable base load around the year, nuclear power is also excluded from the supply of flexibility analysis.

Hydro assumptions and limitations

Based on Pöyry assumptions, 55% of the Finnish hydro capacity is estimated to be flexible, i.e. hydro power plants in river systems with reservoirs. The rest is run-of-river hydro with no flexibility and production driven by weather conditions. This results in flexible hydro capacity of 1.75 GW. In this study we assume that production exceeding the capacity of non-flexible run-of-river plants is provided by the flexible share of hydro. This is illustrated in Figure 3-4.

Figure 3-4 – Hydro power between flexible and run-of-river production



Further assumptions for hydro flexibility are presented in chapter 3.3.2 by evaluating historical production data and industry interviews.

CHP assumptions and limitations

This study looks at CHP flexibility on a national level[17] and does not take into account, e.g. local weather conditions which can have an impact on the dispatch of individual CHP sites.

The available upwards flexibility is limited to the potential of the plants in operation (available capacity). As the analysis in this study is not conducted on a power plant level, it is possible that during certain hours the actual available flexibility deviates from what the analysis would indicate. Dispatch order is assumed not to have an effect on down-regulation, as CHP plants can be assumed to be always capable of reducing production from a technical perspective.

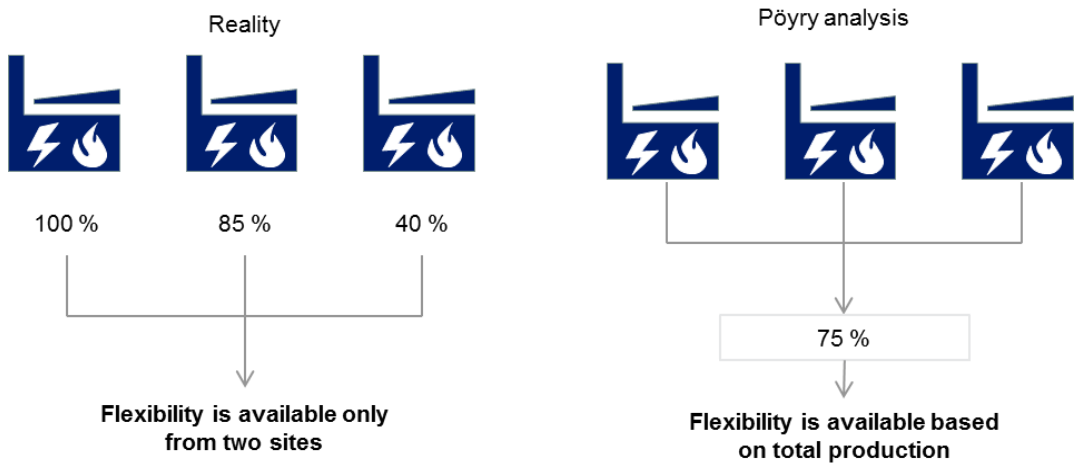
Figure 3-5 illustrates an example of the dispatch order effect, when three CHP sites are running and one of the sites is operating at full capacity. In this case the CHP site running at full capacity has no available flexibility upwards, while the two other sites operating at part load can provide flexibility upwards. The approach used in this study evaluates the combined total production of these sites (equalling to 75% of total capacity from the three sites[18]), not taking into account the constraint of one site being unavailable for up-regulation.

Despite the limitations of this assumption, the chosen approach is considered reasonable as historical individual plant data was unavailable for this study.

[17] Plant level historical data was not available for this study.

[18] Total production = combined running production / combined maximum capacity = (100% + 85% + 40%) / 300% = 75%.

Figure 3-5 - Dispatch order effect on CHP flexibility analysis



Figures (%) represent the share of running capacity from nameplate capacity.

Interconnector flexibility assumptions and limitations

The interconnector analysis is focused on the Swedish border as most of the cross-border flexibility is provided through these interconnectors. We have not considered ramping limits in our analysis as they apply to interconnectors connecting the Nordic region to the Continent.[19] Estonian and Russian interconnectors can also provide flexibility to Finland. However, as Estonia is not part of the Nordic balancing market, there is no public data available on how much Estonian flexibility is available for balancing the Finnish system and therefore is excluded from our analysis. Similar reasoning applies to Russia as well where the situation is further complicated by the impact of the Russian capacity payments affecting imports to Finland considerably.

3.3.2 Historical production data

Hydro flexibility benchmark

According to Fingrid, hydro power is the main contributor to the balancing market in Finland[20]. Hydro is considered as a flexible production source around the year, with only the spring flood season limiting the available potential[21]. To determine the capability of hydro flexibility, the average ramp rate for flexible hydro has to be evaluated.

Based on interviews with hydro plant operators the ramp rate for an average flexible hydro plant is roughly 20-30% of nameplate capacity within a 15 minute interval, when considering environmental restrictions. When applied to the flexible hydro capacity of 1.75 GW, we get a potential of approximately 500 MW within 15 minutes. When considering technical potential within one hour, ramping with the same rate for the whole hour would lead to ramping up to the maximum flexible capacity. When considering the restraints provided through interviews and evaluating the historical data, Pöyry has assumed that the maximum hourly flexibility potential from hydro is 1.0 GW for up-regulation.

To verify this assumption, Pöyry analysed historical production data from the benchmark year 2016. According to public production data from Finnish Energy[22], hydro production peaked at 2.7

[19] https://www.nordpoolgroup.com/trading/Day-ahead-trading/Ramping/

[20] https://www.fingrid.fi/globalassets/dokumentit/fi/ajankohtaista-tapahtumat/reservipaiva-2018-reservienhankinnan-ajankohtaiskatsaus.pdf

[21] During the spring flood season hydro plants might have to bypass turbines as the water flow exceeds the capacity of the turbines.

[22] https://energia.fi/en/news_and_publications/statistics/electricity_statistics

GWh in 2016, with 1.2 GW up-ramps during a 3-hour period and 0.65 GW during a one hour period (65% of the running capacity for the 1 hour ramp). Considering the previously estimated potential within 15 minutes and the observed hourly ramps from a purely technical perspective, we can conclude that the assumption of hourly maximum flexibility of 1.0 GW is feasible for up-regulation. According to the same data, hydro ramped down 1.0 GW within a 3-hour period and 0.5 GW during a one hour period. As ramping down was on a lower level compared to ramping up, Pöyry has assumed that the maximum hourly flexibility from hydro is 0.8 GW for down-regulation.

Down-regulation potential is limited by the running share of flexible hydro production. For the purpose of this analysis we have assumed that hydro production below 0.8 GWh/h is considered only as run-of-river, thus yielding zero down-regulation potential. This assumption is based on historical data which indicates that significant downwards ramping has occurred to a level of 0.8 GWh/h. The basis for this approach was discussed in chapter 3.3.1.

These estimates are conducted from a technical point of view for national level changes[23], taking into account the constraints provided by electricity producers through interviews. As hydro is technically highly capable of providing flexibility, national level historical data does not accurately describe the total technical potential. Pöyry has combined the historical data benchmarks with the interviews to provide a reasonable estimate of the technical potential within one hour.

Table 3-1 displays the observed and estimated hydro power production figures from 2016.

Table 3-1 – Hydro power production (GWh), **capacity and ramping** (GW), **2016**

Source		**Nameplate capacity**	**Max production**	**Flexible capacity**
Hydro		3.2 GW	2.7 GWh	1.75 GW
Ramp direction	**Max. 1h ramp**	Share of running cap.	**Max. 3 h ramp**	Share of running cap.
Up	0.65	65%	1.2	90%
Down	0.5	25%	1.0	40%

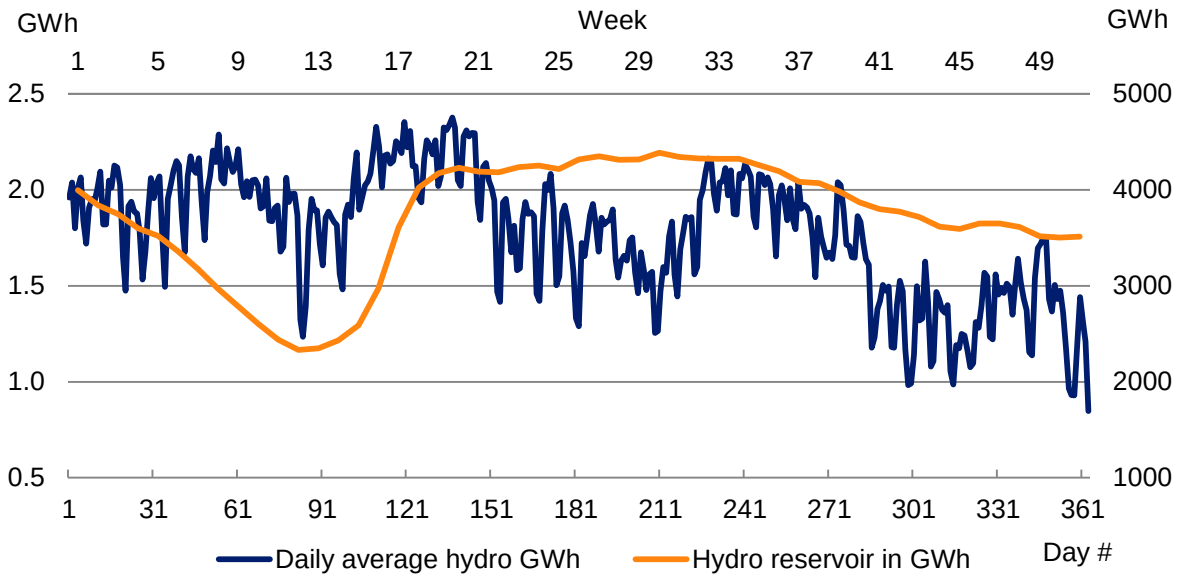
Source: Pöyry analysis, data source: Finnish energy

To evaluate the availability of flexibility around the year, hydro reservoirs are analysed. Figure 3-6 illustrates the average daily hydro production and weekly reservoirs in the benchmark year 2016. As can be seen from the figure, hydro reservoirs are constantly over 2,000 GWh during the benchmark year. As the focus of this study is on the short term technical flexibility potential, it is reasonable to assume, that these reservoir levels are always sufficient to provide flexibility. The only exception is spring flood season, when there is little or no upward flexibility available.

Flexibility potential from individual plants is limited by the local conditions, such as environmental constraints (spring flood, fishing areas etc.) and past production. As individual plant level data was unavailable for this study, we have estimated hydro flexibility based on national level data and interviews. Based on the national level data, upward flexibility is not limited by the reservoirs outside of the spring flood season.

[23] Plant level historical data was unavailable for this study.

Figure 3-6 – Average hourly hydro production per day (GWh) **and weekly Finnish hydro reservoir level** (GWh), **2016**



Source: Pöyry analysis, data source: Finnish energy, Nordpool

CHP flexibility benchmark

CHP (combined heat & power) flexibility is divided into district heating CHP (DH CHP) and industrial CHP. District heating CHP production follows heat demand around the year, thus limiting the available flexibility with the seasonal conditions. Industrial CHP production is more stable compared to DH CHP throughout the year. In the summer time industrial CHP production is reduced by 25% on average from the start of year, whereas DH CHP drops by 85%.

Based on the interviews with CHP operators, the ramp rates of individual CHP plants are 1-5% of nameplate capacity per minute. Ramp rates depend heavily on the plant and fuel in question: gas turbines are highly flexible whereas traditional coal power can be much slower to ramp. On a national level, the largest hourly ramp observed with DH CHP production was 350 MW, equalling 20% of running capacity (roughly 15% of national DH CHP capacity).

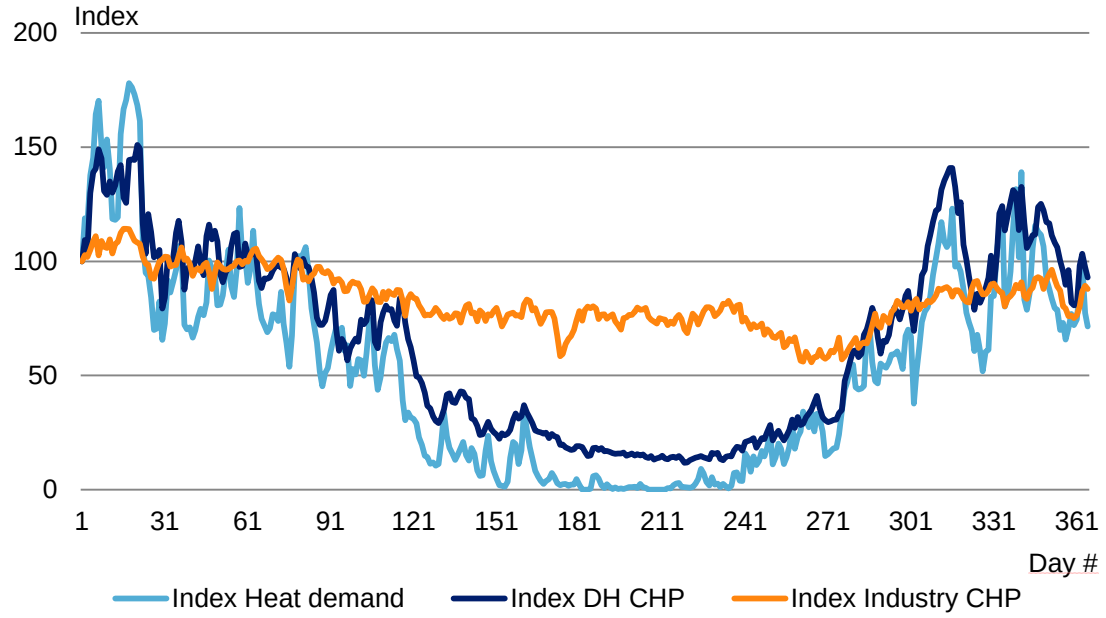
As the fuel mix of Finnish CHP pants is diverse[24], national level production changes fail to capture individual plants' high ramps. Hence, the observed hourly ramps of the total national production are lower than individual CHP plants capabilities would indicate. Also, due to a large number of plants and the production dependency on local heat or steam demand, CHP plants are not reacting only to the demand for flexibility in the power system.

Figure 3-7 displays the yearly variation of DH CHP and industrial CHP production as well as heat demand during the benchmark year 2016. The figures are indexed from 100 to provide a comparable picture of the yearly variation. As can be observed from the figure, DH CHP follows heat demand while industrial CHP is fairly stable throughout the year.

Figure 3-8 illustrates a snapshot of CHP production from week 3 in 2016. The figure shows how industrial CHP production is fairly stable, while at the same time DH CHP varies daily. DH CHP clearly follows the daily electricity demand profile. The highest ramps occur during morning and afternoon demand peaks.

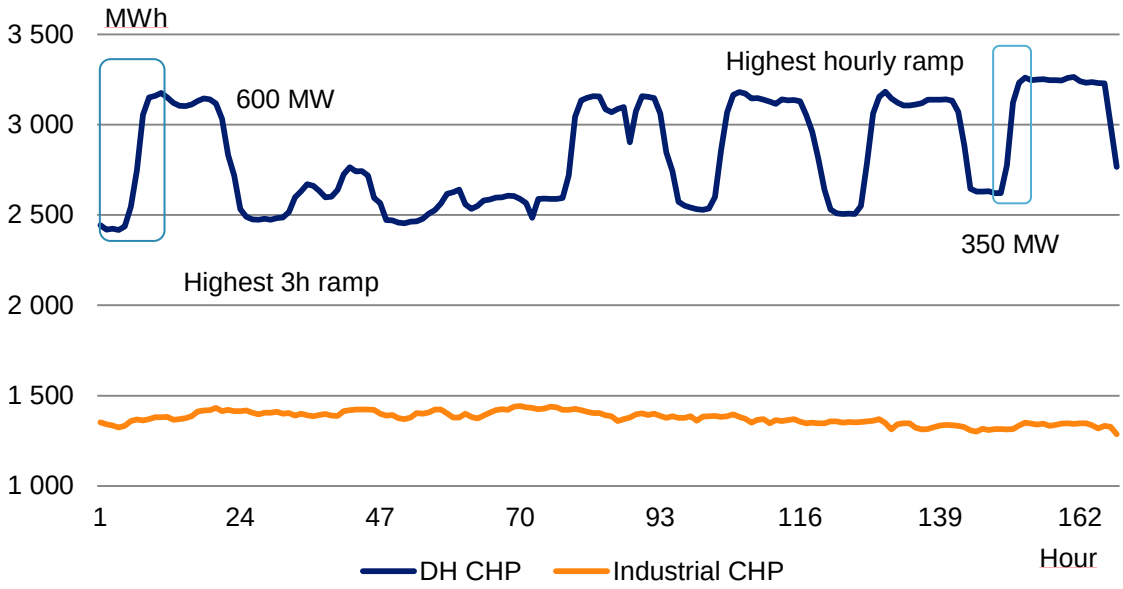
[24] DH CHP fuel mix constitutes of: coal 24%, biomass 34%, peat 15%, gas 12%, with the rest covered by oil, waste and other sources. Source: Finnish Energy.

Figure 3-7 – Average daily CHP production and heat demand index (January 1st, Day 1 = 100)**, 2016**



Source: Pöyry analysis, Data Source: Finnish Energy

Figure 3-8 – Hourly CHP electricity production (MWh), **week 3 in 2016**



Source: Pöyry analysis, Data Source: Finnish Energy

Table 3-2 shows the observed maximum hourly ramps and production of DH CHP in 2016.

Table 3-2 - Observed CHP ramping (MW) and production (MWh), 2016

Max.	DH CHP	Industrial CHP
1h ramp, MW		
Up	350	75
Down	-450	-100
Production, MWh		
Hourly	3 300	1 400

Source: Pöyry analysis, Data source: Finnish Energy

Based on the analysis conducted, Pöyry has assumed that the technical capability of both DH CHP and industrial CHP on a national level is 20% of running capacity for both up- and down-regulation. The flexibility is naturally capped to the maximum production capacity i.e. increasing running production by 20% will not exceed the nameplate capacity**.**

Pöyry has taken a somewhat conservative view on the technical flexibility potential of CHP, as the purpose of this study is to analyse capabilities on a national level. Based on the industry interviews, individual plants are capable of higher production increases, but as already discussed in chapter, this study ignores the dispatch order effect for individual plants. Thus, to provide a safe assumption of what is available at minimum, the above capability assumption has been made.

3.3.3 Flexibility potential for 2016 for production

Based on the production benchmarks, Pöyry has created an estimate of the flexibility potential for the benchmark year. This estimate is used to evaluate assumptions made in this study, as historical data is available for the evaluation. The potential estimate is then benchmarked against historical balancing market bids to evaluate the flexibility estimate.

Estimate of flexibility potential for benchmark year 2016

Hydro flexibility is estimated as follows:

- Up-regulation potential is the difference between running production and the annual maximum production, capped to the maximum one hour ramp of 1.0 GW.
  - For example, if the maximum hydro production is 3,000 MWh/h, and the running capacity is 2,200 MW, up-regulation potential is assumed to be 800 MW.
  - If the running capacity is 1,500 MWh, the up-regulation potential is assumed to be 1,000 MW as the difference to maximum production is greater than 1.0 GW[25].
- Down-regulation potential is the running capacity of flexible hydro capacity, capped at 800 MW. As was discussed in the previous section, we have assumed that hydro production below 800 MWh/h is considered run-of-river. This assumption is based on historical data which shows that significant downwards ramping has occurred to a level of 800 MWh/h.

The flexibility of CHP is assumed to be +/- 20% of running capacity on a national level, capped to the nameplate capacity. For example, with a running capacity of 1,000 MW, the available up- and down-regulation potential is assumed to be +/- 200 MW.

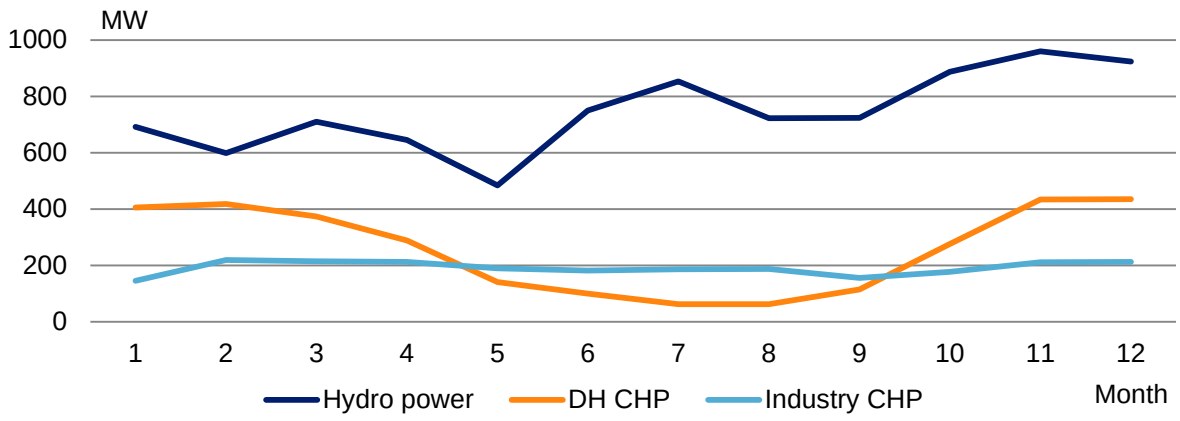
If the production is close to full capacity, the flexibility potential is limited by the nameplate capacity. In this case the up-regulation potential is the difference between the running capacity and

[25] 3,000 MW–1,500 MW = 1,500 MW (>1,000 MW). Thus, the up-regulation potential is estimated to be 1,000 MW.

nameplate capacity: for example with a production of 2,900 MWh and a maximum production of 3,000 MWh, the up flexibility potential is assumed to be 100 MW.

Figure 3-9 represents Pöyry's estimation of the monthly average flexibility potential in 2016.

Figure 3-9 –Monthly average of hourly up-regulation potential (MW) from production, 2016



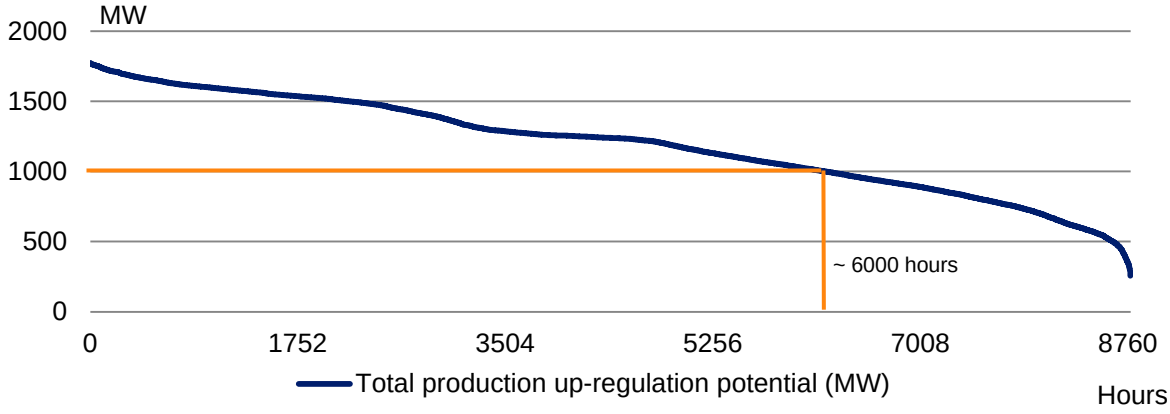
Source: Pöyry

Hydro was the main source of flexibility according to Pöyry analysis in 2016, with DH CHP varying during the year and industrial CHP providing fairly stable potential. The analysis also indicates that production flexibility potential is lowest during the spring time, when hydro power is running at high capacity and DH CHP production is decreased due to reduced heat demand.

Figure 3-10 represents the duration curve of the total production technical potential[26] in 2016; the curve represents the sum of hourly available flexibility from different sources sorted in order of high to low. This gives the share of values over a certain threshold; for example for approximately 6000 hours per year there is over 1,000 MW of up-regulation potential.

[26] Total potential from production flexibility is not the sum of individual production flexibility sources, as the maximum potentials of each source might not occur during the same hour.

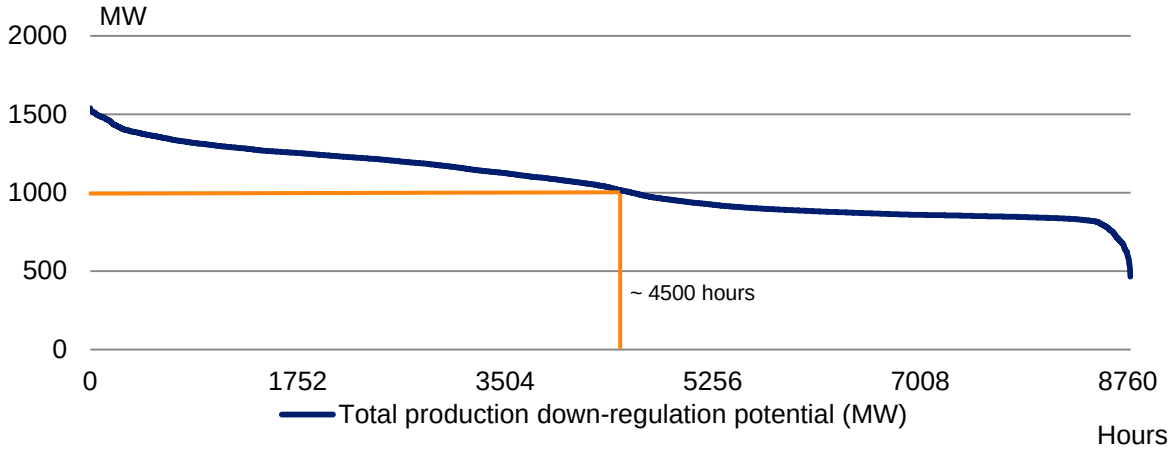
Figure 3-10 – Total production up-regulation technical potential (MW) duration curve, 2016



Source: Pöyry

Figure 3-11 represents the down-regulation total technical potential duration curve in 2016. Down-regulation potential was approximately over 1.0 GW for 4,500 hours in 2016.

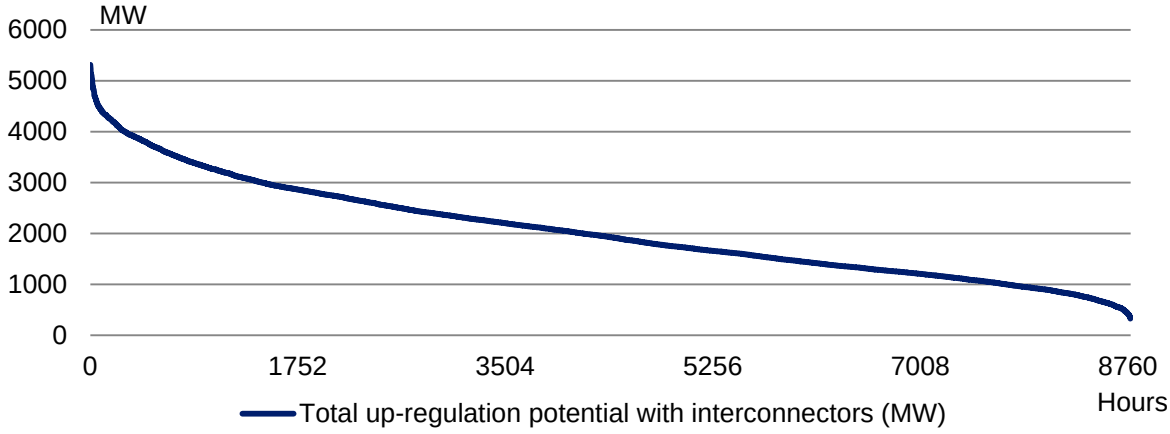
Figure 3-11 – Production down-regulation technical potential (MW) duration curve, 2016



Source: Pöyry

To provide the total technical flexibility potential for 2016 interconnector flexibility potential from Sweden has to be evaluated. Based on historical data analysis, interconnectors provided significant potential for majority of the year. When summed together with production flexibility for each hour, we get the total technical flexibility potential, which varied between 1,000 MW and 3,500 MW roughly 85% of the time. Figure 3-12 illustrates the total up-regulation potential duration curve in 2016.

Figure 3-12 – Technical total up-regulation potential (MW) duration curve, 2016



Source: Pöyry

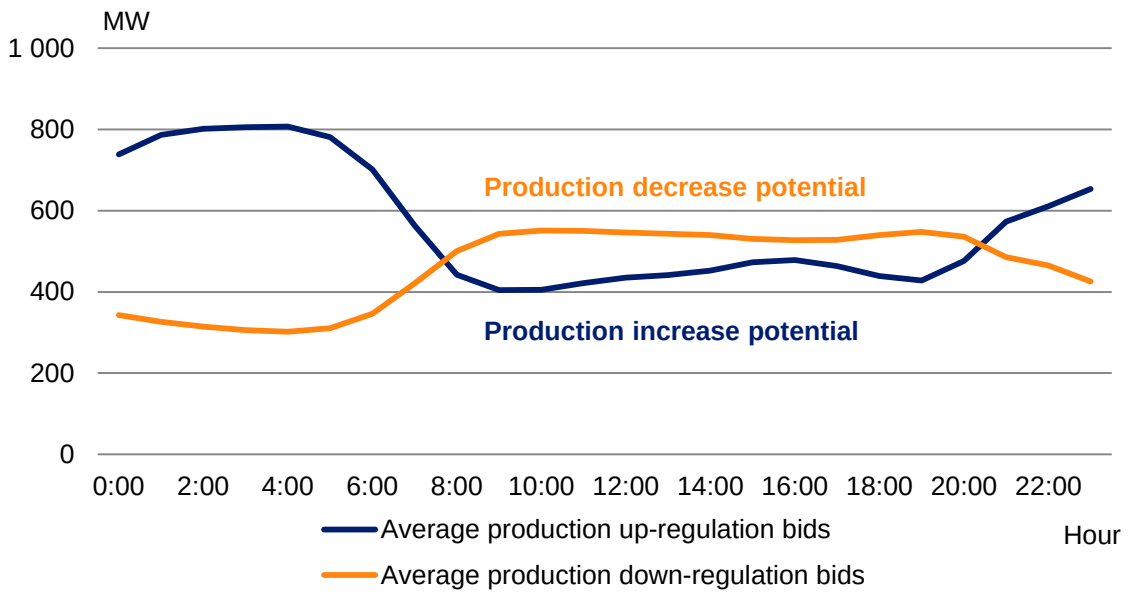
Benchmarking against balancing market bids

To create another benchmark for the estimation of the potential flexibility, and to evaluate the feasibility of our flexibility potential estimation methodology, data analysis of balancing market bids was carried out for 2016 and 2017.

As discussed in chapter 3.3.2 and observed in Figure 3-8, CHP producers increase their power production during morning hours, thus having less up-regulation potential during day time. Based on the analysis, balancing bids follow the same profile: up-regulation bids are lower during day time and down-regulation bids a higher. This can be seen from Figure 3-13.

Up-regulation potential appears to halve after the morning peak hours, climbing back after the evening electricity demand decline. Conversely, down-regulation potential grows during the morning peak, but only by approximately 50%, and declines with the evening demand decline.

Figure 3-13 – Average hourly up and down balancing market bids (MW) from electricity production, 2017

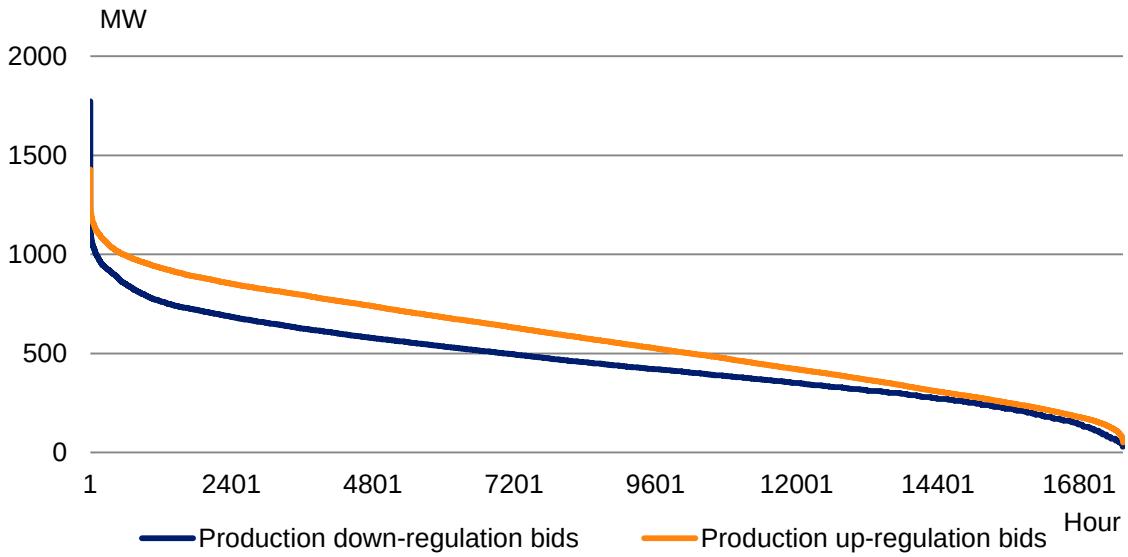


Source: Pöyry analysis, data source: Fingrid

Based on the interviews with market participants, high marginal cost bids are not necessarily bid into the market consistently due to the low probability of bids going through. Some of the flexible production is also bid into other markets or withheld due to other constraints as was illustrated in Figure 3-2.

Estimating total technical flexibility potential is expected to yield higher flexibility potential than what has been historically observed through balancing market bids. When comparing our technical estimate for flexibility from electricity production (Figure 3-10 and Figure 3-11) with historical balancing market bids in Figure 3-14, we can observe our estimation yielding a similar range of values for flexibility: 1.5 GW to almost zero. However, as expected when estimating technical potential, our flexibility potential estimate is on average on a higher level especially at the lower end of the duration curves. Based on the conducted comparison we have evaluated our approach to estimating flexibility potential as feasible.

Figure 3-14 – Duration curve of balancing market bids (MW), production 2016–2017



Source: Pöyry analysis, data source: Fingrid

3.4 Demand-side flexibility

Based on the interviews and analysing balancing market bids, Pöyry has compiled an estimate of the technical flexibility potential from the demand-side. As a rule of thumb, processes, where electricity forms a major share of the cost of the end-product cost, have more potential for demand-side flexibility.

Our analysis focuses on industrial demand-side flexibility, as it provides majority of demand-side flexibility. Industrial DSR originates from large industrial operators such as paper mills or steel factories, but also smaller operators, such as greenhouses, can be aggregated to form a larger pool of flexibility. Flexibility from greenhouses is mainly offered to the disturbance reserve market (outside the scope of this study) due to more predictable income and less activations than in the balancing or intraday markets.

For industrial demand-side flexibility, available flexibility is dependent on at least:

- production targets, e.g. on a weekly level;
- process status and capacity;
- interim storage capacity and utilisation;
- environmental and security restrictions; and
- workforce availability.

As many of these factors are not public knowledge, flexibility potential from demand-side is estimated on an average level based on historical bid data and interviews with industrial operators.

3.4.1 Demand-side flexibility potential

Chemical industry

Chemical industry is a large energy consumer in Finland. According to the interviews, providing flexibility is a standard procedure for chemical industry. The current technical potential appears to be reached, as additional flexibility could be found from automation and support functions such as pumping. Not everything is offered to the markets due to high marginal cost of providing bids.

According to the interviews short-term flexibility for duration of 0-3 hours is available in the following way, given that other restrictions are not limiting the capability[27]:

- 10% of peak demand is available within 15 min
- 25% within 1 hour
- 50% within 3 hours

Process stability and safety were highlighted in the interviews; small adjustments can potentially disturb the process for days, thus providing flexibility to the electricity markets is not done automatically.

Based on the interviews, Pöyry has estimated the overall flexibility potential to be roughly 150 MW within 3 hours and 75 MW within one hour.

Metal industry

Metal industry has the most consuming individual consumers in Finland, thus making the industry highly suitable for providing balancing to electricity markets. According to stakeholder interviews, the various processes are capable of providing flexibility within a short time frame, but process restrictions limit the duration of activated flexibility to few hours.

The following capabilities have been identified from the metal industry on average:

- Up to 300 MW of demand-side flexibility could be available within an hour
- Roughly 200 MW is estimated to be available within 15 min
- Preferred demand reduction periods are a few hours at a time

The interviews highlighted that standard balancing products do not always fit with the process-specific characteristics, i.e. certain processes are not able to meet technical requirements of standard products, thus limiting the potential offered to market.

Paper industry

Paper industry is the largest source of demand-side flexibility. Paper machines on average are highly capable of providing flexibility without disturbing the process.

- According to interviews, up to 60–70% of paper industry demand offers flexibility actively in the market
- Pöyry has estimated the flexibility potential to be 550 MW within fifteen minutes and 600 MW within one hour. Interim storages enable the provision of short-term flexibility for 0-3 hours. The duration of flexibility mostly has an impact on the cost of provision and meeting production quotas.

[27] The higher the duration of flexibility, the more restrictions there are e.g. from meeting production quotas. However, technically the processes are able to provide flexibility for a period of 3 hours.

Data centers

Data centers have potential to provide quick balancing, but at the moment market penetration is small. Offering flexibility can be seen to risk data center power supply.

Technical potential from data centres connected to the Finnish power system has been estimated up to 200 MW within a few seconds, but less than 10 MW is active in the market at the moment.

Uninterruptible power supply (UPS) system allows disconnecting from the grid and switching to back-up diesel generators;

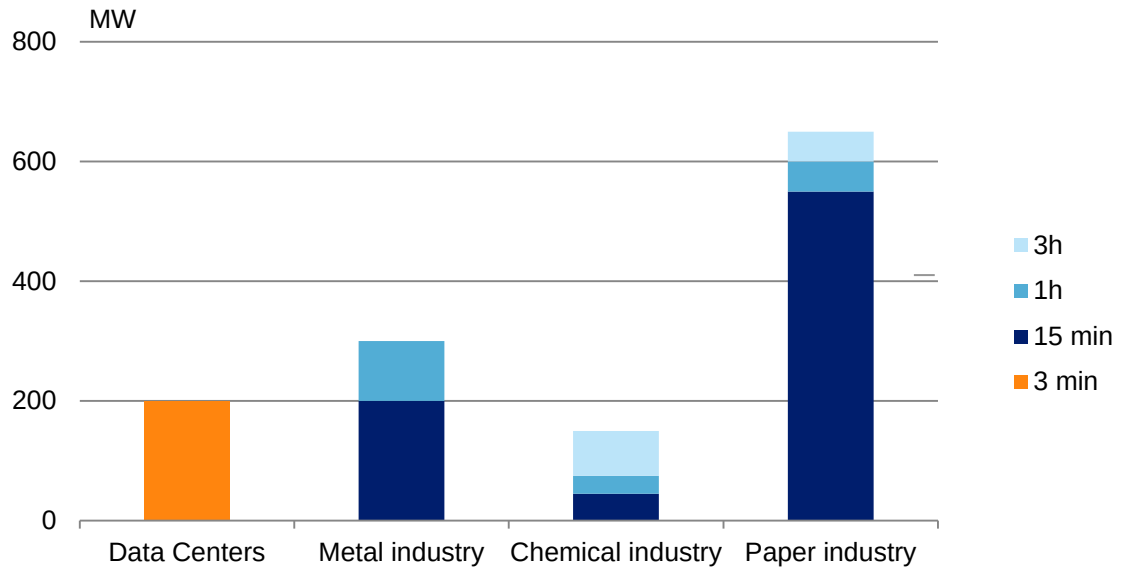
- Maximum run-time for back-up generators 250 h/a
- Typically data centers have their own back-up generation, but lack automation
- Initial investment in automation is roughly EUR 10–30k

However, as the setup is based on back-up generation and is therefore more suitable for providing frequency containment reserve for disturbance (FCR-D), our analysis does not include flexibility from data

Technical demand side flexibility potential

Pöyry has estimated the technical flexibility potential from industrial sites to approximately 1.0 GW within one hour for 0-3 h duration. Figure 3-15 illustrates the flexibility from different sources.

Figure 3-15 – Demand-side technical flexibility potential with different activation times (0-3 h duration)



Source: Industry stakeholder interviews, Pöyry analysis

The majority of the estimated potential is available around the year but due to the dependency on market situation and other restrictions discussed earlier, it is difficult to evaluate the potential on an hourly resolution. Also, Fingrid has contracted 400 MW of industrial balancing for OL3 disturbance reserve until November 2020, thus reducing the available flexibility for other balancing markets.

Benchmarking against balancing market bids

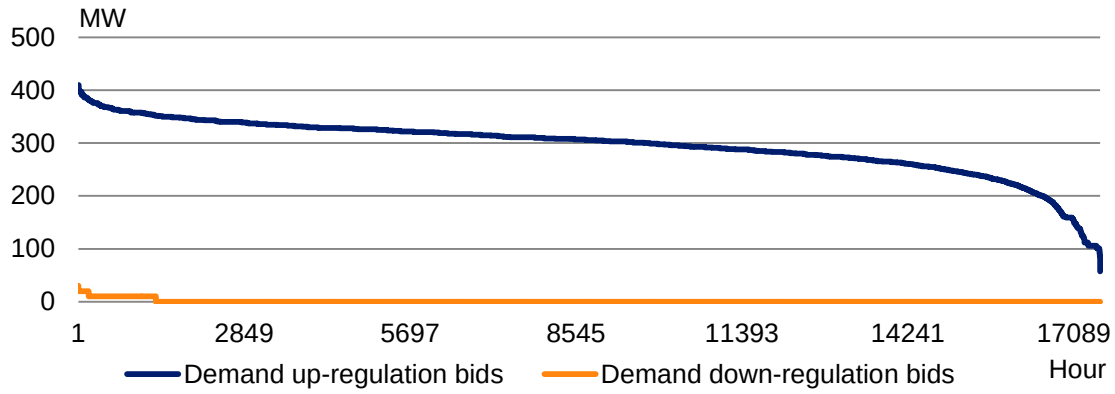
When evaluating against balancing market bids from 2016 and 2017, we can see that on average the bids are around 300 MW for up-regulation. Down-regulation bids are almost non-existent, as industrial plants are designed to operate close to maximum capacity on a regular basis, hence

reducing the availability to increase their electricity consumption. Figure 3-16 illustrates the duration curves for up- and down-regulation bids from 2016 and 2017.

Based on the analysis conducted, it appears that approximately 1/3 of the technical potential is offered to the balancing markets. According to the interviews, the remaining potential is not bid into the market due to high marginal cost of providing "low probability bids". This could also help explain why there are very little down-regulation bids. More opportunistic bids could be submitted also for down-regulation, e.g. at negative prices, if the bidding process was more automated. Flexibility can also be offered to other markets, such as reserves.

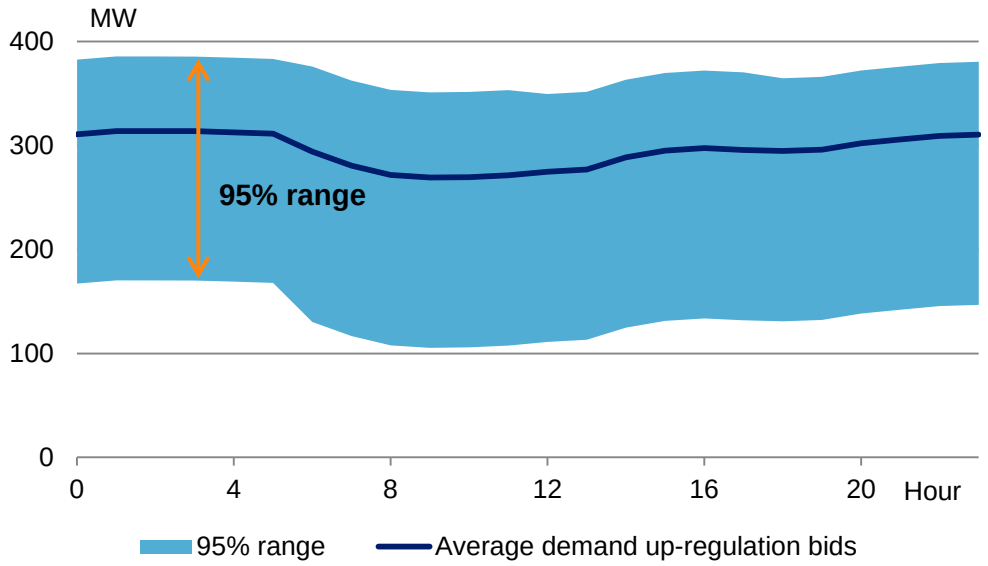
Figure 3-17 presents the range and within day variation of up-regulation bids from 2016 and 2017. The analysis indicates that approximately 95% of up-regulation bids are in the range of 100–400 MW, with the maximum value peaking just above 400 MW and the minimum value just over 60 MW. The average bid level is approximately 300 MW around the year.

Figure 3-16 – Demand regulation bid (MW) duration curves 2016–2017



Source: Pöyry analysis, data source: Fingrid

Figure 3-17 – Hourly demand up-regulation bids (MW), 2016-2017



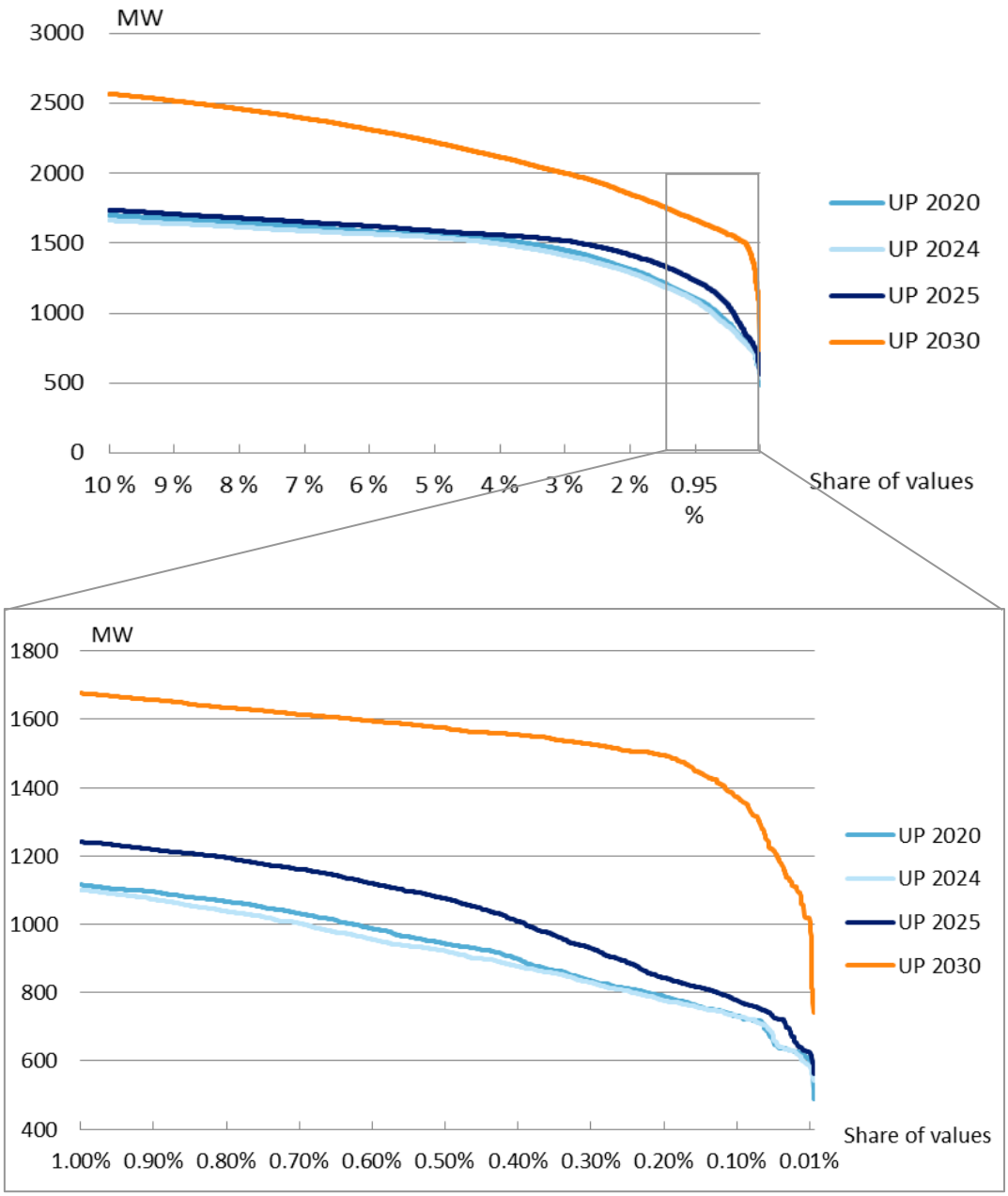
Source: Pöyry analysis, data source: Fingrid

3.5 Future supply of flexibility

Duration curves for up-regulation potential for 2020-2030

Figure 3-18 shows the duration curves over the analysed weather years for 1 h activation time and 0-3 h duration. The up-regulation potential is over 600 MW for 99.99% of the time in 2020, 2024 and 2025. In 2030 the situation is even better, with up-regulation potential exceeding 1.0 GW for 99.99% of the time. In 2030 up-regulation potential is expected to be approximately on a 30% higher level on average compared to years 2020–2025, due to the commissioning of Hanhikivi 1 nuclear power plant and the new interconnector between Finland and Sweden.

Figure 3-18 – Up-regulation potential duration curves (2020, 2024, 2025 and 2030)



Source: Pöyry

Confidence levels indicate the share of values, which are over a certain level. The 99.7% and 99.99% confidence levels for up- regulation potential are shown in Table 3-3. For example, 99.7%

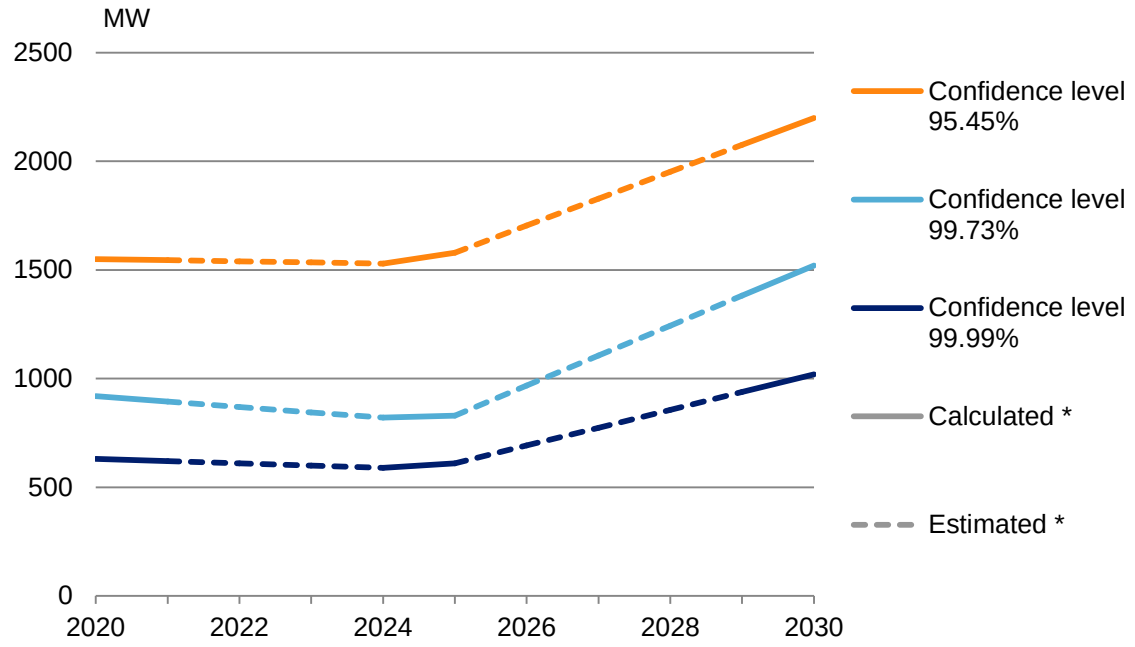
of up-regulation potential is estimated to be over 0.8 GW in 2024. This converts to approximately 2.5 hours per year when the potential is less than 0.8 GW. Figure 3-19 illustrates the confidence level development until 2030.

Table 3-3 – Confidence levels for up-regulation potential (2020, 2024, 2025, 2030)

Confidence level, %	Up 2020, GW	Up 2024, GW	UP 2025, GW	Up 2030, GW
95	1.6	1.5	1.6	2.2
99.7	0.9	0.8	0.8	1.5
99.99	0.6	0.6	0.6	1.0

Source: Pöyry

Figure 3-19 – Up-regulation potential confidence level (MW) development, 2020 to 2030



*Calculated values are for 2020, 2024, 2025 and 2030. Values between these years have been interpolated between them.

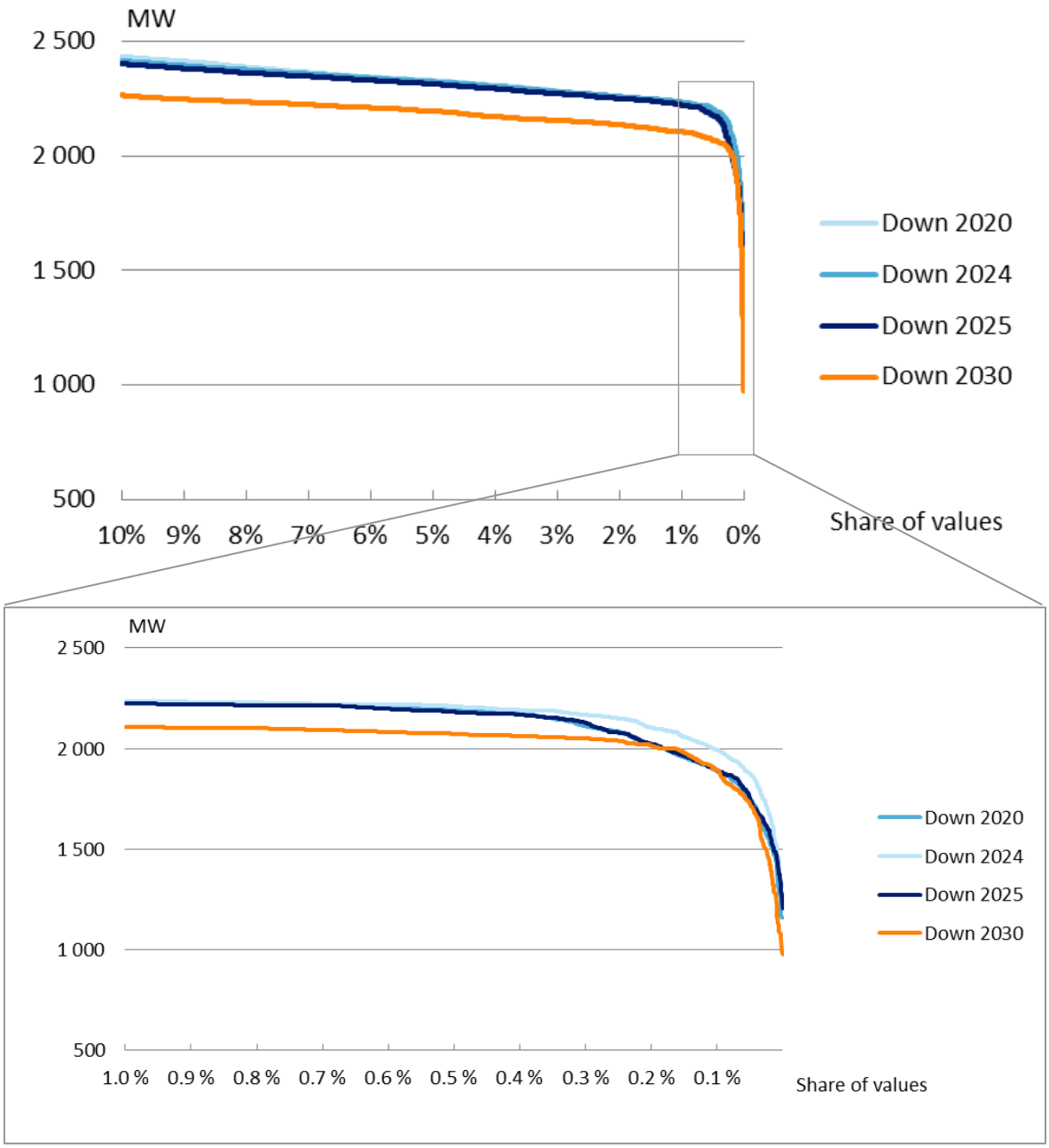
Source: Pöyry

Duration curves for down-regulation potential for 2020–2030

Figure 3-20 represents the down-regulation potential duration curves for analysed years. The down-regulation potential is over 2.0 GW for 99.97% of the time. Table 3-4 presents the confidence levels for down- regulation potential and Figure 3-21 illustrates the confidence level development for down-regulation until 2030.

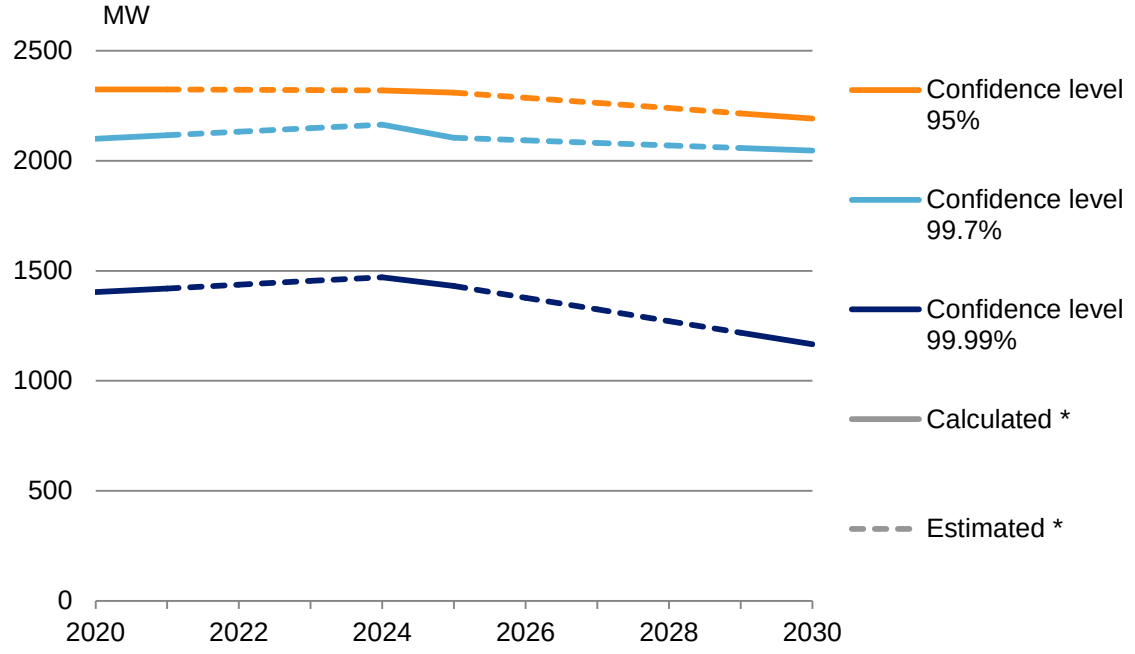
Periods of low down-regulation potential are likely to occur during hours of low hydro production and high interconnector exports from Finland. Conversely, high down-regulation potential is due to low interconnector exports from Finland, with hydro providing additional flexibility.

Figure 3-20 – Down-regulation potential (MW) duration curves, (2020, 2024, 2025, 2030)



Source: Pöyry

Figure 3-21 – Down-regulation confidence level development until 2030



Source: Pöyry

Table 3-4 – Confidence levels for down-regulation potential (2020, 2024, 2025, 2030)

Confidence level, %	Down 2020, GW	Down 2024, GW	Down 2025, GW	Down 2030, GW
95	2.3	2.3	2.3	2.2
99.7	2.1	2.2	2.1	2.0
99.99	1.4	1.5	1.4	1.2

Source: Pöyry

3.6 Combining supply and demand of flexibility

Demand and supply of flexibility are combined to estimate how likely it is that the supply will not be able to meet demand. The combination is done by comparing the aggregated supply of flexibility with the total demand for flexibility. Only demand from forecast error is looked at because the way supply of flexibility was estimated:

- Supply of flexibility estimates are done by simulating the hourly profiles of demand, and corresponding generation and interconnector flows and estimating the available flexibility based on those.
- This means that the hourly profiles of flexible generation and interconnector (IC) flows have already the net demand swings taken into account.
  - Typically the swings in net demand are supplied with 1) adjusting IC flows, if there is available cross-border capacity, 2) ramping domestic hydro up or down, and 3) ramping domestic thermal power.
- The supply of flexibility shown is then additional supply that can respond to demand for flexibility caused by forecast errors. In a way, the hourly modelling results represent a ‘perfect

foresight' situation on how the market would clear based on the historical weather patterns. Hence, the residual demand for flexibility comes from forecast errors on top of the weather patterns, which form the basis for the hourly demand profiles, hourly swings and corresponding generation and IC flow profiles.

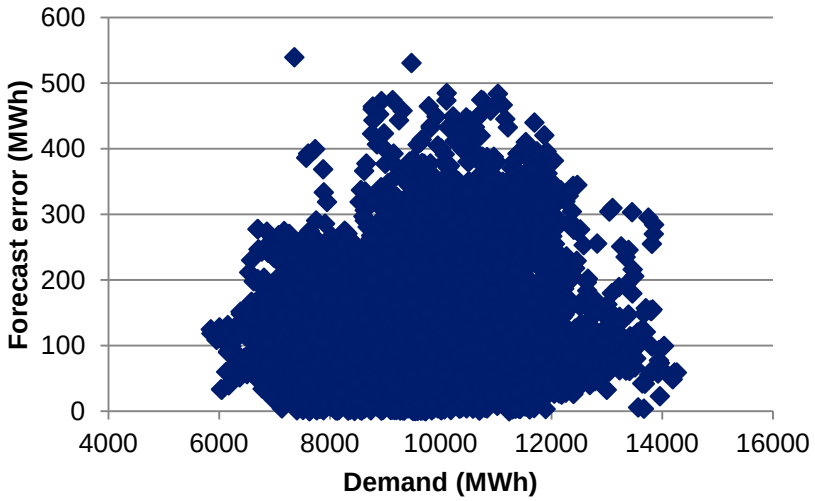
This analysis focuses on the supply of up-regulation as issues with down-regulation are less likely than for up-regulation.

Figure 3-22 shows the hourly demand forecast error plotted against the demand during the same hour in 2017. As there seems to be no correlation between the two, this would point to the fact that the size of the demand forecast error is not proportional to the level of demand. This means that we can assume that demand for flexibility due to demand (consumption) forecast error is not higher during winter or morning demand peaks, when the supply of flexibility might be low.

The hours with low supply of up-regulation are typically periods with low wind production in our simulated hourly profiles which already contain the assumption that demand is met during those periods. This means that the potential wind forecast error does not have a significant impact on the up-regulation potential as the level of wind production is already low.

Because of these reasons, the following results do not assume correlation between demand and supply of flexibility.

Figure 3-22 – Demand forecast error vs. demand (2017)



Source; Pöyry analysis, data source: Fingrid

To make supply of flexibility comparable with the demand the minimum values of supply of flexibility are assumed to follow a normal distribution. Normal distribution characteristics are approximated based on the 99.99% (one hour every two years) and 95% probability intervals for supply of flexibility (see Section 3.5), which for 2024 results in a mean of 2470 MW and standard deviation of 470 MW. This is again a conservative estimate as the supply of flexibility quickly increases after the small low probability figures.

Table 3-5 shows probabilities that the difference between supply and demand is less than value shown in the table. Year 2024 is shown as in the analysis scenario 2024 is the year with smallest gap between demand and supply of flexibility. Overall the probabilities indicate that situations where there is not enough supply are fairly unlikely.

Table 3-5 – Combining supply and demand of flexibility, 2020, 2024, 2030

Supply – demand difference	Probability as number of hours per 10 years		
	2020	2024	2030
0 MW	0.00	0.03	0.00
100 MW	0.00	0.07	0.00
200 MW	0.01	0.2	0.00
300 MW	0.03	0.5	0.00
400 MW	0.09	1.3	0.01
500 MW	0.21	3.0	0.01

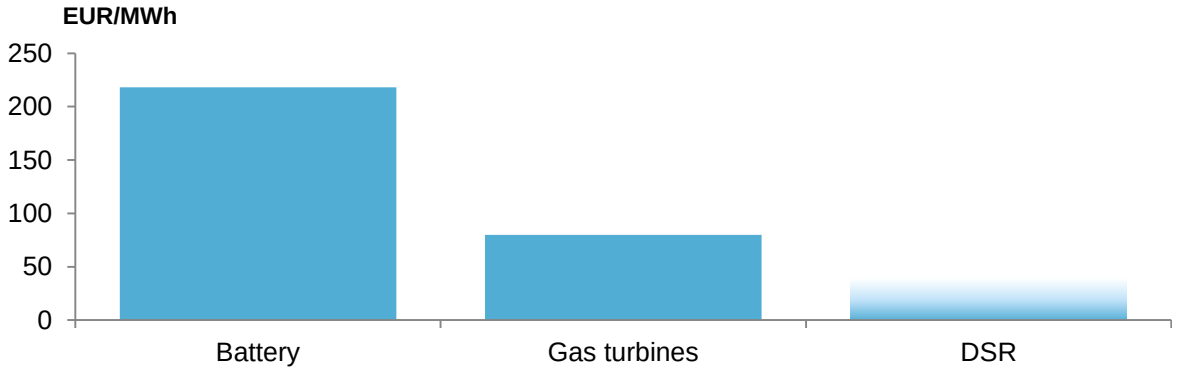
Source: Pöyry analysis
Note: Results are applicable to 15 minutes and 3 hour flexibility durations because neither demand nor supply change significantly between these and one hour situation. For more detail see Sections 2.4.5 and 3.1.

3.7 Cost of adding flexibility

Figure 3-23 shows the levelised cost of batteries and gas turbines, and an indication for the cost demand-side flexibility. The levelised cost of batteries and gas turbines are based on public sources, and the cost of gas turbines is adjusted to represent Finnish gas prices. At current level batteries are still expensive and primarily more suitable for providing frequency reserve.

Previous studies on DSR potential and stakeholder interviews that were conducted in this study indicate that there exists significant potential in the demand-side. Based on interviews many DSR providers bid based on their expectation of activation, and do not bid with full available capacity, suggesting there is significant amount of unused potential. An interview with an aggregator indicated that clients primarily look for stable and predictable revenues from DSR and tend to require payback periods of less than 1 year, also suggesting that there is unused potential. Exact cost for adding flexibility is difficult to determine as there is a range of flexibility which can be offered to the market at different price levels even for a single demand-side resource (e.g. different phases of an industrial process).

Figure 3-23 – Levelised cost of flexible technologies



Source: Lazard, Pöyry analysis

4. SENSITIVITY ANALYSES

4.1 Flexibility from residential customers

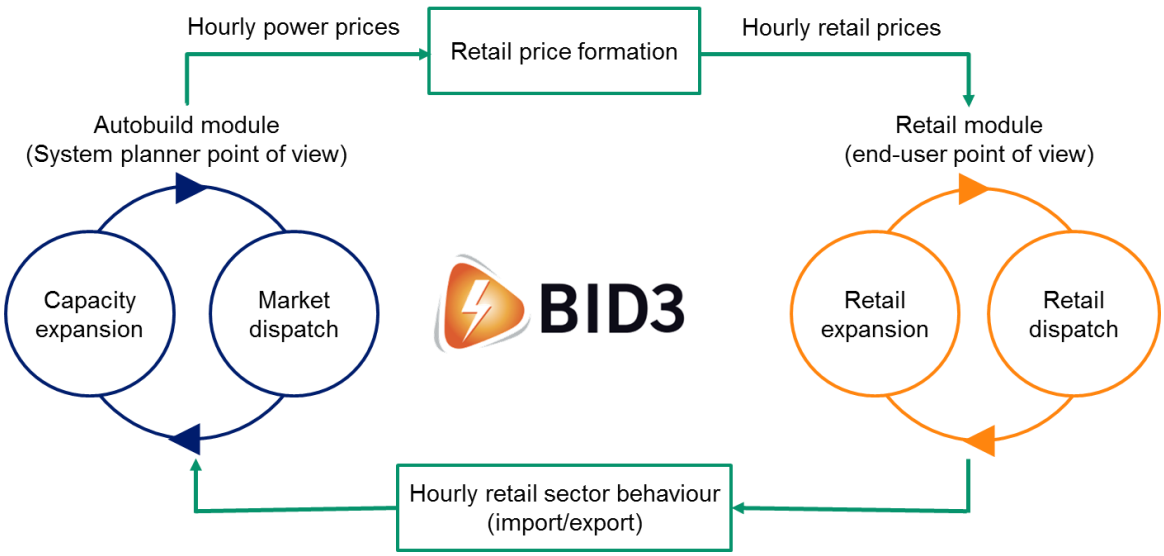
This section describes the results from the analysis of the flexibility from residential customers. This part of the analysis was carried out using the methodological framework of the Tipping Points multiclient study, which looked at the impact of very low technology costs on power markets in Europe. The Tipping Points study looked at investment and dispatch decisions in the wholesale and retail markets.

In this analysis, the same analytical framework is used, but assumptions are different: cost assumptions are more akin to a 'Business as usual' rather than a disruptive evolution of technology costs.

4.1.1 Methodology and assumptions

The Tipping Points study has a complex methodology, and the aim in this report is not to describe its entire dataset and algorithms. Figure 4-1 shows a high-level summary of the methodology: the principle is to produce a consistent outcome between investment decisions and dispatch at the wholesale level (autobuild module) and retail level (retail module). Wholesale players work to maximise their profit, which is equivalent in perfect market to minimising system costs. At the retail level however, end-customers aim to reduce their retail bill in the long term, potentially by making investments behind-the-meter and by dispatching their resource (EV charging, battery operation) optimally given their retail tariff incentives.

Figure 4-1 – Optimisation framework



Source: Pöyry

This project has involved two elements of development compared to the original Tipping Points study:

- Participation of residential space and water heating flexibility at the retail level – both in terms of investment in flexible heat enablers (control systems), and the optimal provision of heat during the day; and
- Setting retail grid tariffs per maximum observed import from the grid – effectively a capacity-based tariff in euros per maximum kW consumed.

Retail scenario set-ups

The study has modelled retail electricity tariffs containing different incentives for flexibility. There are different elements, presented in Table 4-1:

- Energy: represents the resolution of the wholesale component in power prices within the retail bill. In the 'Annual price' scenario, customers are exposed to flat wholesale prices, while in other scenarios retail customers are exposed to hourly-varying power prices.
- Grid Fixed, Grid Variable: grid fees are charged through a mix of fixed costs (either 'per household' or 'per maximum kW imported from the grid') and variable ('per kWh consumed').
- Electricity tax: either charge per kWh consumed or as a percentage of the hourly wholesale price.
- Flexible heat: flexible heat is either a calculation based on profitability calculations of installing control systems ('Calculated') or forced to be fully deployed on all electric boilers ('Forced 100%').
    - The demand profile is based on a combination of customers with heating with water circulation and customers with direct electric heating (estimated to be roughly 85%) with an average consumption of 15 MWh/a.

Table 4-1 – Retail scenario set-ups

	Energy	Grid fixed	Grid variable	Electricity tax	Flexible heat
Annual price	Flat	Per household	EUR/kWh	EUR/kWh	Calculated
Hourly price	Hourly	Per household	EUR/kWh	EUR/kWh	Calculated
kW-based grid	Hourly	Everything as peak hour	No	EUR/kWh	Calculated
Energy tax %	Hourly	Per household	EUR/kWh	% of hourly wholesale	Calculated
kW-based grid and energy tax %	Hourly	Everything as peak hour	No	% of hourly wholesale	Calculated
kw-based grid and energy tax % + flex heat	Hourly	Everything as peak hour	No	% of hourly wholesale	Forced 100%

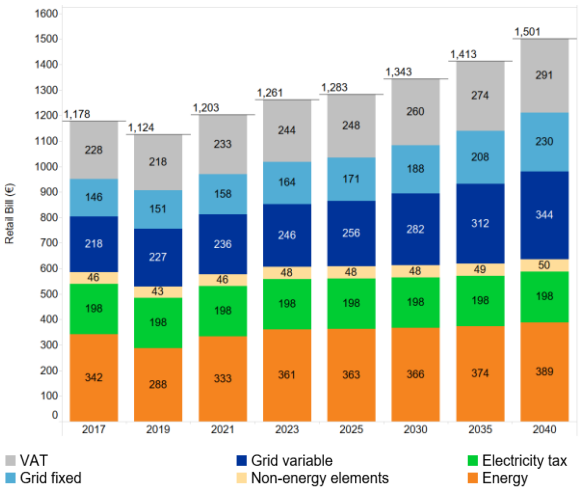
Retail bill components

Figure 4-2 shows the evolution of the annual retail bill over time, using today's dominant retail bill structure in Finland. In particular, it illustrates that we have assumed that the electricity tax is assumed to stay flat at €22.53/MWh. Grid charges are assumed increase by 2% per annum, which is in line with the historical development of prices[28].

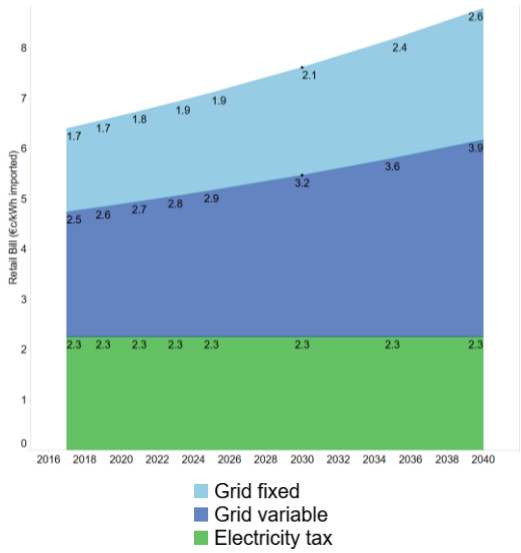
[28] Source: Sähkön jakelutariffien kehitys 2000-2017. Energiavirasto. 2017.

Figure 4-2 – Retail bills – today's structure* (Rigid)

Annual retail bill (€/year)



Grid and electricity tax components (€c/kWh)



*Illustrative average retail bill for a residential customer with an annual consumption of 8.9 MWh/year.
Source: Original Pöyry Tipping Points study. Prices are shown in real 2016 money.

Cost assumptions

The assumed cost development of investing in demand-side response capabilities for electric heating are presented in Table 4-2. The starting point is based on the cost levels of the solutions currently available in the Finnish market, e.g. OptiWatti, Fortum Fiksu and CleBox. Due to technological development and economies of scale we have assumed that the prices would decrease quite significantly by 2030.

Table 4-2 – Cost development of investing in making electric heating flexible

Item	Unit	2018	2020	2025	2030
Investment cost*	EUR	1000	900	725	550
Service fee	EUR/a	60	60	48	36

All figures are in real terms.

*Including the tax credit for household expenses ('kotitalousvähennys')

For solar PVs we have assumed that investment costs would drop by 20% by 2030 and operating costs by roughly 30%. The cost development for batteries is assumed to lead to a 40% decrease in investment costs and roughly a 50% decrease in operating costs by 2030.

Electric vehicles

The take-up rate is based on the objective in the National Energy and Climate Strategy to have 250,000 electric vehicles by 2030.[29]

[29] Source: Valtioneuvoston selonteko kansallisesta energia- ja ilmastostrategiasta vuoteen 2030. Työ- ja elinkeinoministeriö. 2017.

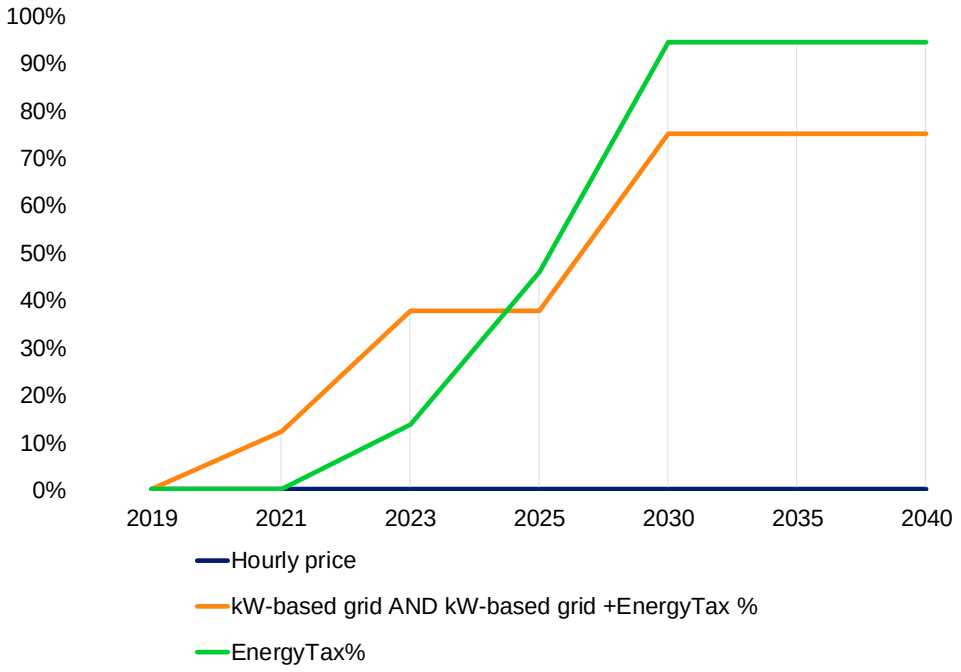
4.1.2 Results of the modelling

Take-up rate of flexible heating

The economic case for adopting flexible heating is driven by the retail tariff structure. Figure 4-3 shows the evolution of the economic case for installing flexible heat control systems over time. There are three drivers behind the gradual investment in technology:

- The volatility in the wholesale market tends to increase over time (although only moderately);
- The cost of installing heat flexibility control systems decreases over time; and
- the representation of the residential retail sector is done assuming a range of 'willingness to invest in technology', which means that flexible heat is developed by successive waves.

Figure 4-3 – Percentage of residential customers with flexible heating



Source: Pöyry

Exposing the customers only to wholesale price variations does not justify the capex for installing flexible heating in the 'Hourly price' scenario. The overall contribution of the wholesale price to the retail bill stays low and the general Nordic price shape remains relatively flat over time.

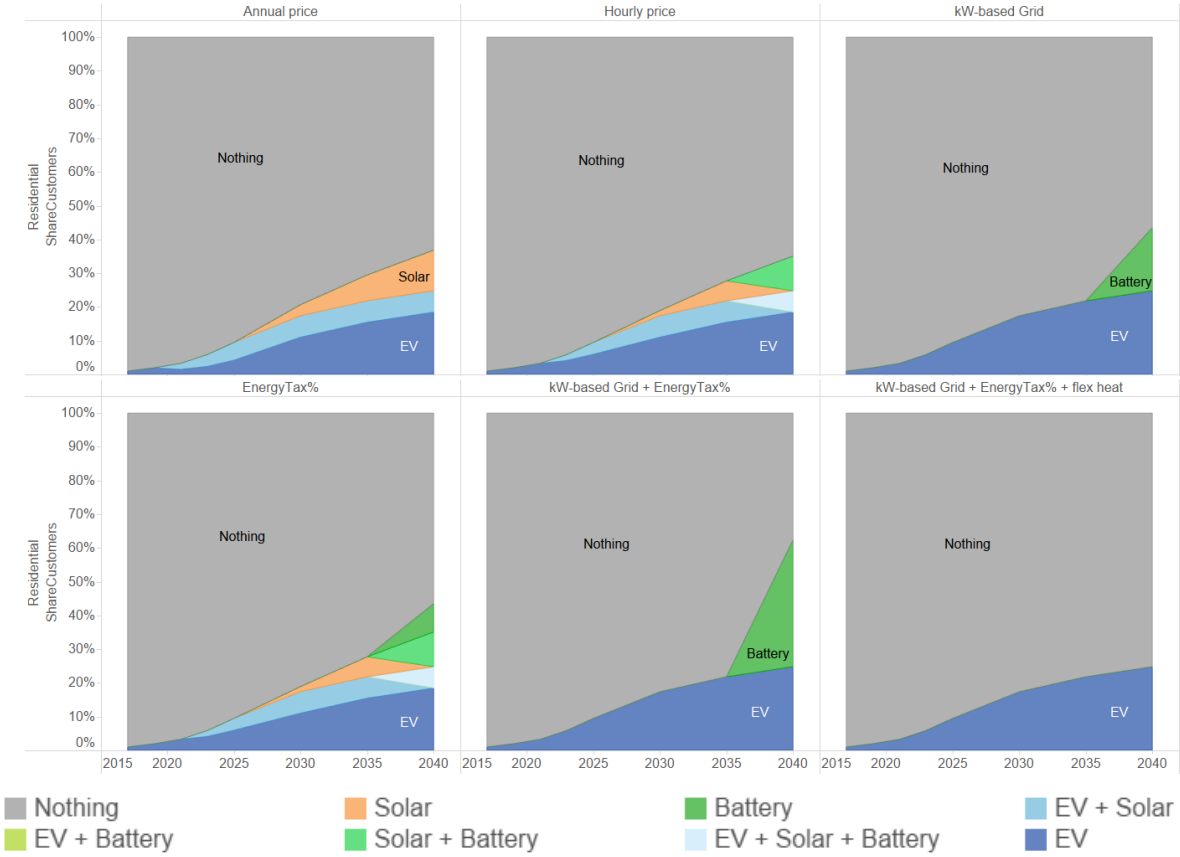
The EnergyTax% scenario creates the best case for investing in flexible heating, as the extra flexibility enables customers to reduce their consumption during the hours when wholesale prices are high (as the energy tax is priced as a percentage of the wholesale price, the overall price volatility increases).

Both scenarios where grid costs are expressed as a function of peak imports create a good case for investing in heat flexibility from early years (reaching 75% by 2030). This is exacerbated by the fact that all grid costs charged based on the peak import capacity.

Investments in household solar and batteries

Figure 4-4 shows the evolution of 'equipment' in the retail sector in the different scenarios presented earlier in Table 4-1. The figure represents the percentage of retail residential customers with EV, solar, battery or a combination of several pieces of equipment (e.g. EV+solar, or EV+battery).

Figure 4-4 – Retail sector investments



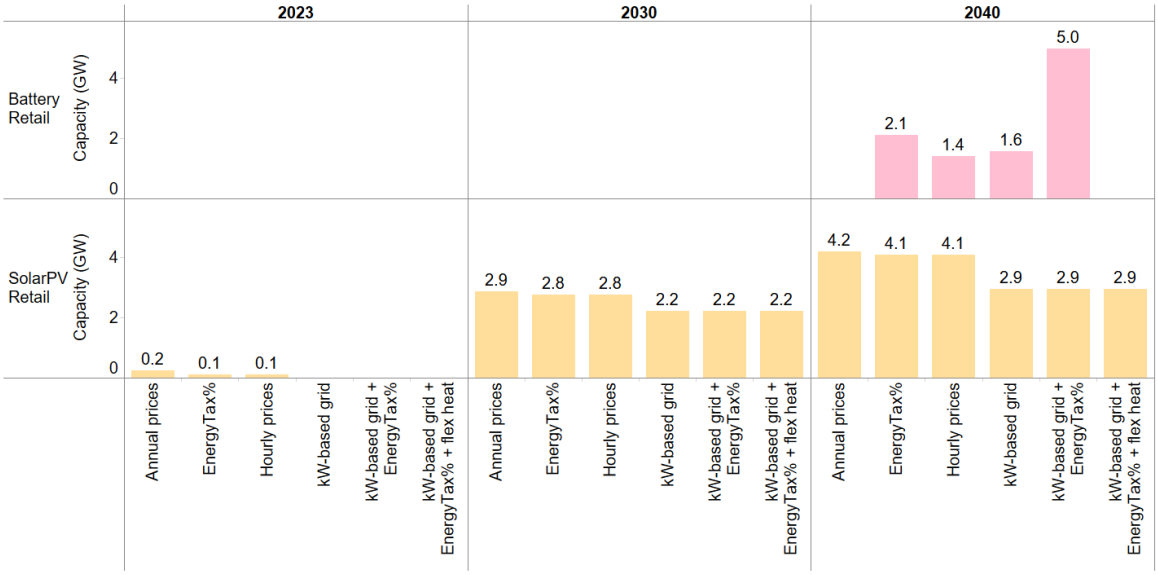
Source: Pöyry

The first five scenarios contain an optimised level of flexible heat, as reported in Figure 4-3. Flat retail prices (the 'Annual price' scenario) encourage solar build-out for households both with and without EVs. Passing hourly prices to households (the 'Hourly price' and 'EnergyTax%' scenarios) create a favourable business case for solar with a source of flexible (either EVs or batteries). Batteries become increasingly profitable when grid fees are charged as a function of peak demand, as there are strong incentives to flatten the demand profile as much as possible. The forced introduction of flexible heat ('kW-based grid + EnergyTax% + flex heat') removes the business case for any behind the meter installations.

Figure 4-5 shows specifically the installed capacity of solar and batteries behind-the-meter, expressed in GW.

Behind the meter solar begins to appear in 2023 at a steady rate, whereas batteries appear only in 2040. Batteries appear most strongly in the case where the hourly wholesale price shape is reinforced by an electricity tax as percentage of hourly wholesale prices: effectively the wholesale price volatility signal is increased at the retail level. When combining electricity tax charged as a percentage of hourly wholesale prices with kW-based grid tariffs, investment in behind-the-meter battery is the highest.

Figure 4-5 – Solar PV and Battery behind the meter for residential customers

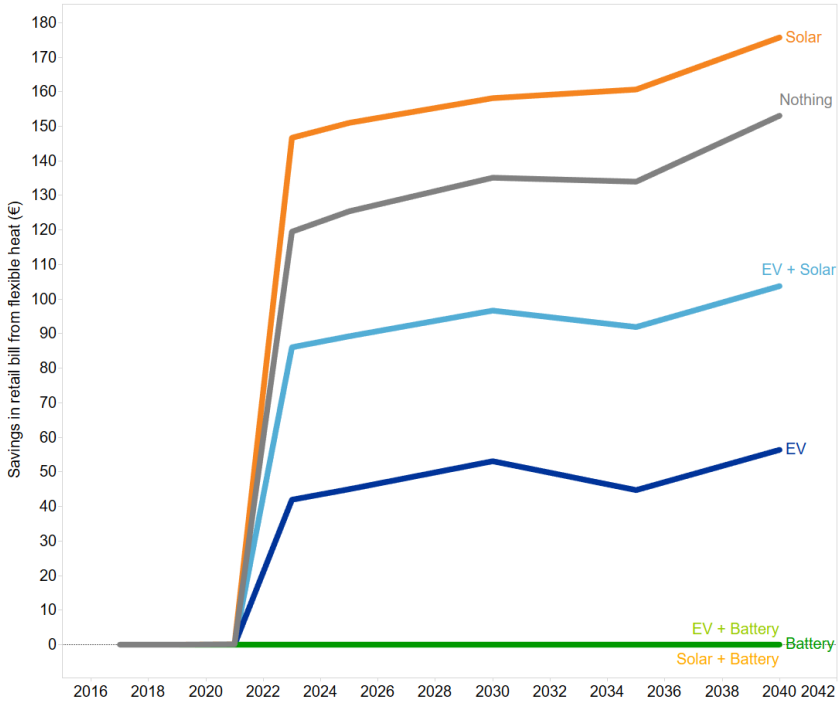


Source: Pöyry

Combining flexible heating with other technologies

Figure 4-6 shows the savings brought by installing heat control systems to save retail costs. The metric can only be calculated starting from 2023 where the deployment of the technology becomes positive.

Figure 4-6 – Savings from adding flexible heating



*Averaged for all customers. The savings would be more for customers with space heating and water circulation and less for customers with direct electric heating (water boilers as the main source of flexibility).
Source: Pöyry

Flexible heat has been modelled under a retail tariff where hourly wholesale prices are passed directly to customers, grid fees are charged as a function of peak demand and policy support costs are a function of hourly wholesale prices

The advantages provided by flexible heat can be clustered in three groups:

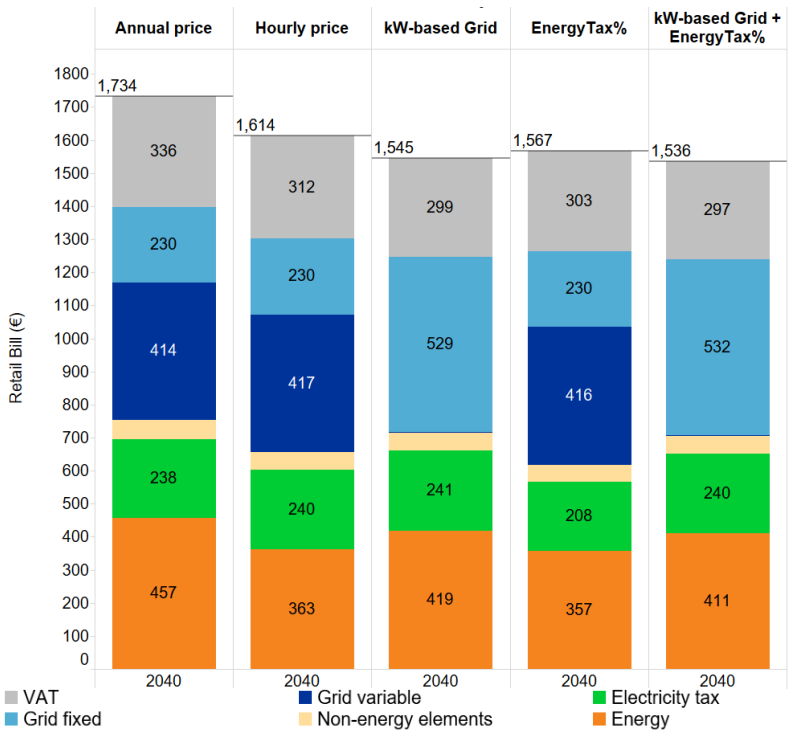
- High benefits (up to 20%) if there is no other source of flexibility on site
- Moderate benefits (up to 7%) is combined with the flexibility provided by electric vehicles
- No benefits if combined with batteries (hence exceeding the required amount of flexibility)

It is also interesting to see that the benefit does not increase over time significantly from 2023: the deployment of the technology supresses the increase in wholesale price volatility.

Impact of tariffs on user behaviour

Figure 4-7 shows the structure of the retail bill for residential customers in 2040. The split between fixed and variable grid charge is the most striking difference between the scenarios.

Figure 4-7 – 2040 electricity bills under different arrangements



Within the analysis framework of the study, retail tariffs change consumer behaviour perfectly: if customers have a 'signal' from the hourly structure of retail tariffs, they will attempt to minimise their retail bill. Figure 4-8 shows the average import from the grid for a very flexible household (with both EV and battery) – most of the households in Finland would effectively have a lower level flexibility, but the graph illustrates well the potential behaviour of end-customers. The elements of importance on this graph include the facts that:

- Exposing households to hourly prices (EnergyTax% and hourly prices scenario) pushes customers to consume power at night and between the two daily peaks in order to minimise their cost of electricity; and
- Charging the grid fees based on peak demand fundamentally flattens the consumers' demand profile, in order to avoid paying grid charges based on a high maximum import from the grid.

Pöyry has modelled a grid charge based on the maximum level of consumption during the year. There are also other designs possible in the same vein, in particular charging customers based on the three highest metered imports from the grid within a month. Such a structure wouldn't change the behaviour observed in the model, and could on the contrary exacerbate it: when charged on the maximum consumption during the year, summer consumption has more room for variations (until the peak consumption level set in winter) than when the maximum summer consumptions directly influences the grid cost for the summer.

Finally, it should be noted that the two signals (hourly pricing and capacity-based tariffs) are competing with each other. Hourly pricing would tend to increase night-consumption while capacity-based tariffs would simply flatten demand and prevent the high weight to overnight consumption.

Figure 4-8 – Average imports from the grid by hour of day (winter months, 2025), for a household with both EV and battery

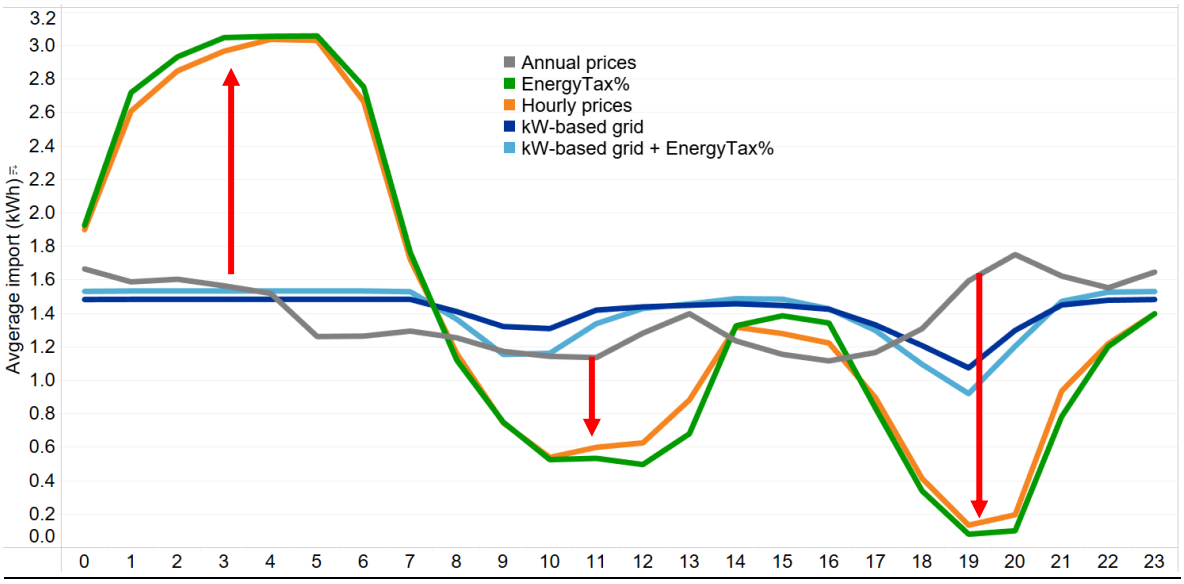
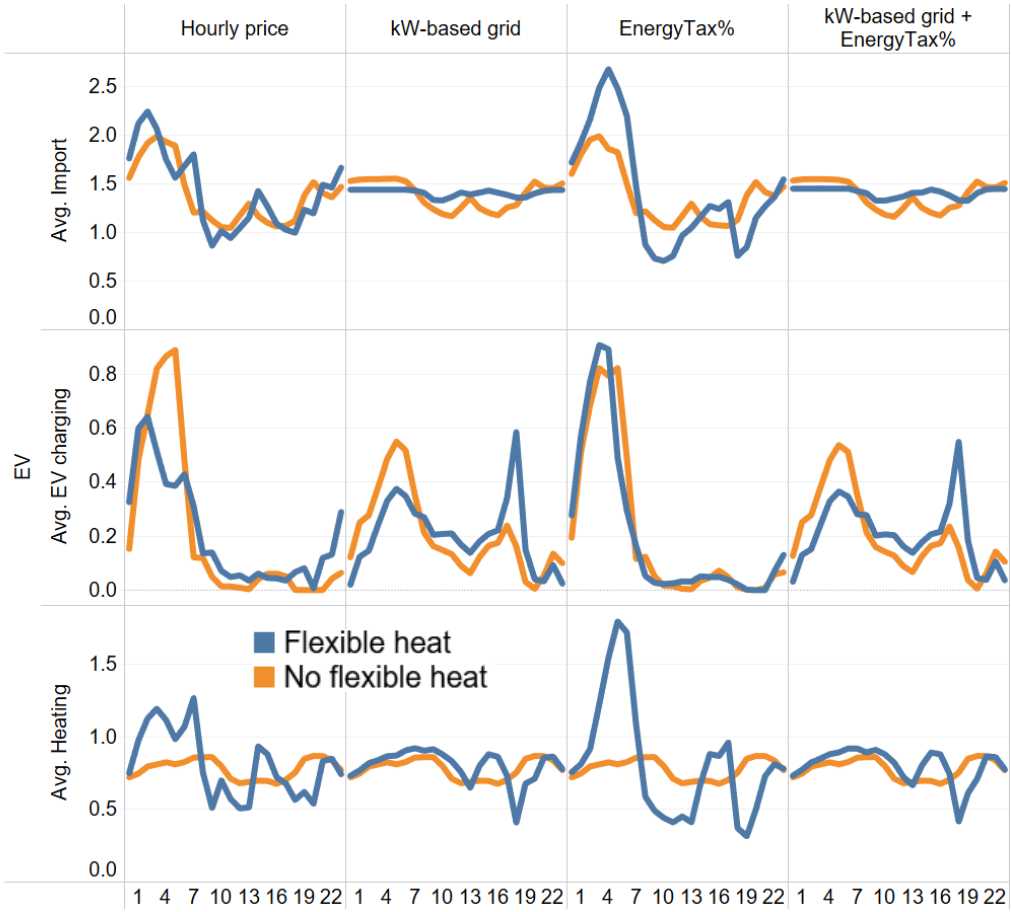


Figure 4-9 shows the same pattern, but introduces the role of flexible heating. As per the previous figure, exposing consumers to hourly prices incentivises overnight demand, while charging the grid fees as a function of peak demand results in a flat import from the grid across the day.

In this particular combination of costs (grid fees vs. hourly price from wholesale and electricity tax), the signal from the capacity-based tariff dominates as can be seen in the flat import in the last scenario presented.

Figure 4-9 – Hour 24 demand patterns – winter months, 2040



Source: Pöyry

4.1.3 Impact on demand and supply of flexibility

The flexibility provided by heating varies significantly with the retail scenario. It varies in terms of amount of flexible heat solution deployment, and in terms of usage. The flexibility in this context is defined as the potential re-scheduling of heat boilers in real time. It can be expressed as such ('up' and 'down' are generation-centred):

Figure 4-10 – Up- and down-regulation provision from household water boilers

$$Down\ regulation\ potential\ (h) = Boiler\ capacity - Boiler\ consumption\ (h)$$

Down regulation provided by increasing the boiler consumption

$$Up\ regulation\ potential\ (h) = Boiler\ consumption\ (h)$$

Up regulation provided by decreasing boiler consumption

$Boiler\ capacity$ is taken at 3kW per household.

Source: Pöyry

By nature, there will be times when there is no up regulation, which is when the boilers are not in use (e.g. at peak time). On the contrary, boilers will have no down regulation when boilers are in full use.

With capacity-based tariffs, it should be noted that the measuring of peak import from the grid should ignore the provision of system services: a customer would not risk providing down regulation if it sets the grid fee paid during the year or the month.

Figure 4-11 to Figure 4-14 show the duration curves of up and down regulation in 2025 and 2030 provided by flexible heat technologies. The figures show a much more 'binary' operation of heat boilers when the hourly wholesale price signal is reinforced by the electricity tax charged proportionally to the hourly wholesale price – the boilers operate at maximum load, and at night. This makes for a more extreme potential provision of up and down regulation. On the contrary, capacity-based tariffs will tend to flatten the heat boiler operations and allow heat boilers to potentially provide (a lower amount) of up and down regulation more systematically.

Table 4-3 and Table 4-4show the impact on overall supply of flexibility when the results from this section are combined with the results in section 3.5. A similar trend can be seen from these results as well. Residential flexibility contributes only slightly to the confidence levels for up-regulation potential due to:

- In the 'kW-based grid' scenario the boiler is running at part load to minimise the grid fee.
- In the 'EnergyTax%' scenario the boilers operate at maximum load at nights which are not periods of low up-regulation potential.

The impact on down-regulation potential is clearly more significant as in our method we have assumed that the boiler can always be switched to run at full capacity.

Figure 4-11 – Up-regulation potential provided by flexible heating in 2025

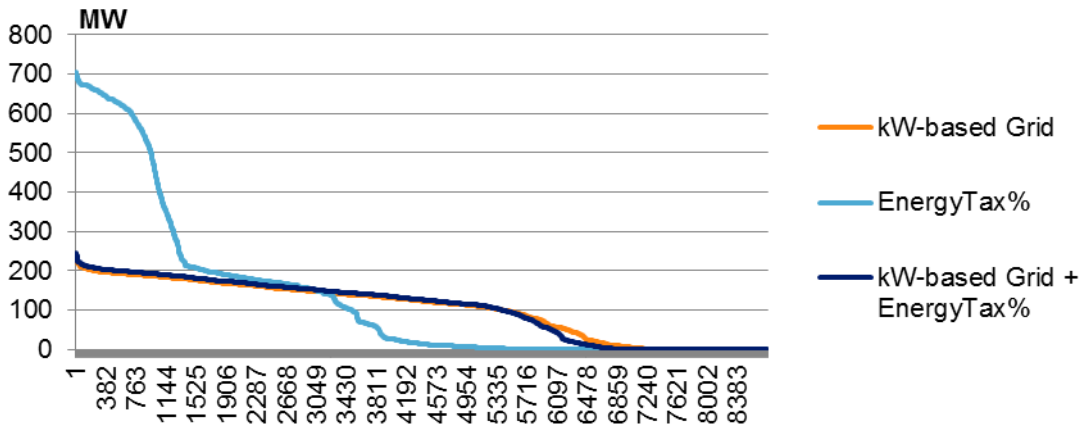


Figure 4-12 – Down-regulation potential provided by flexible heating in 2025

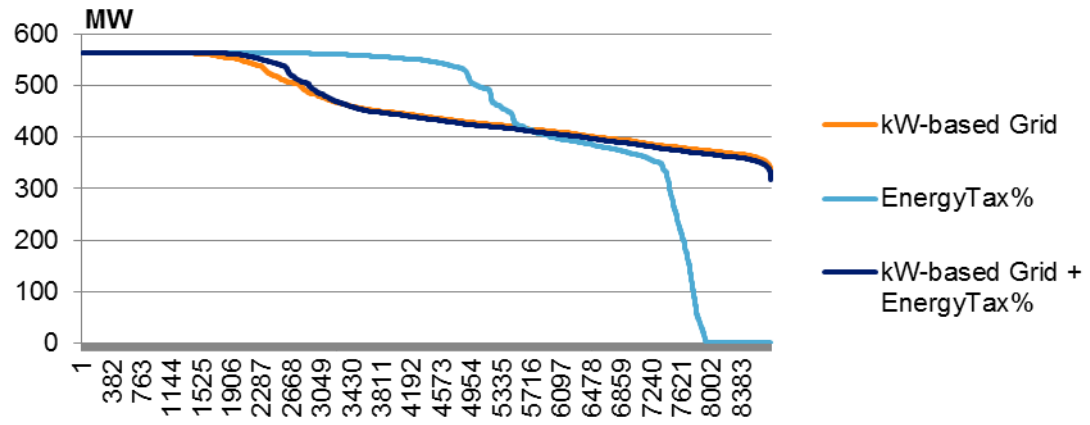


Figure 4-13 – Up-regulation potential provided by flexible heating in 2030

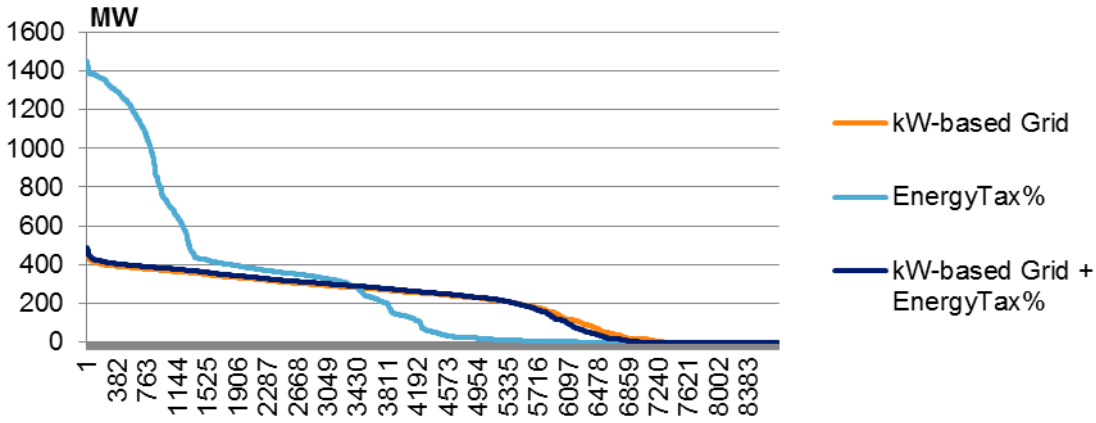


Figure 4-14 – Down-regulation potential provided by flexible heating in 2030

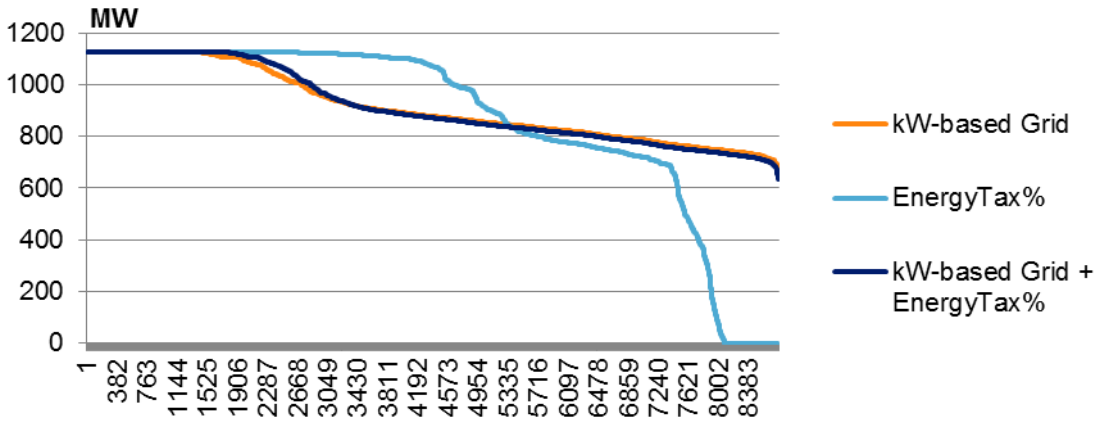


Table 4-3 – Confidence levels for up-regulation potential, GW

	2025			2030		
Confidence level, %	Base scenario	kW-based grid	EnergyTax%	Base scenario	kW-based grid	EnergyTax%
95	1.6	1.7	1.6	2.2	2.4	2.3
99.7	0.8	0.9	0.9	1.5	1.6	1.6
99.99	0.6	0.6	0.6	1.0	1.1	1.0

Source: Pöyry

Table 4-4 – Confidence levels for down-regulation potential, GW

	2025			2030		
Confidence level, %	Base scenario	kW-based grid	EnergyTax%	Base scenario	kW-based grid	EnergyTax%
95	2.3	2.8	2.7	2.2	3.1	2.6
99.7	2.1	2.5	2.3	2.0	2.9	2.0
99.99	1.4	1.8	1.6	1.2	2.1	1.7

Source: Pöyry

The actual up- and down-regulation is not as reliable as conventional methods, i.e. flexibility generation, interconnection and demand-side already on the market, for the reason stated above (boiler sometimes used at maximum level or not at all). These results however do not take into account the fact that boilers could be operated in order to provide this type of services – for example operating at maximum at peak time to be able to provide up regulation. In this case, it should be noted that these services should provide remuneration higher than the extra cost of running the boiler at peak time.

4.1.4 Conclusions

The summary of the main messages from the analysis are as follows:

- Exposing households to hourly prices unlocks the value of residential flexibility and reduces the annual electricity bill.
- Charging the grid fees based on peak demand has the potential to flatten residential demand profile.
- Capacity based tariffs or increased wholesale price volatility are incentives to install flexible heating solutions.
- Flexible heating only brings benefits to households with no other forms of flexibility (EV or battery). However, it is unclear how much the EV storage capacity would be used to optimise household retail bills or whether EV charging is optimised separately.
- If customers react to wholesale prices, they will have a lot of up-regulation potential during short periods of time, but mostly during the night. Optimising against capacity-based grid tariffs provides a smoother flexibility potential profile.

4.2 Impact of removing time-based control by distribution network companies

The Smart Grid Working Group has proposed in its interim report[30] that the time-based control and compulsory time-of-use pricing by distribution network companies should be eliminated in a controlled manner once a sufficient amount of cost-effective automated consumption control services are available for the customers.

This section investigates the impact this would have on the demand profile in the Finnish power system. The time-based control turns on electric heating between 22:00 and 23:00 which can be seen as an increase in the Finnish demand. Table 4-5 shows the average and maximum changes in demand between hours starting at 21 and 22 in January-February, when impact of increased electric heating demand is the highest. The average demand increase in years 2016-2018 was 50-120 MWh and the maximum increase was 320 MWh.

To separate the change in demand due to the activated electric heating load, we have evaluated what the demand would have been without any activation based on the demand changes between hours starting at 20 and 21, and hours starting at 23 and midnight. Table 4-6 shows the estimated change in demand due to the activation the heating loads. The average estimated demand increase was 380-460 MWh and the maximum increase was 600 MWh.

Table 4-5 – Change in demand between hours starting at 21 and 22, January-February

Year	Average, MWh	Maximum, MWh
2016	46	247
2017	111	272
2018	118	316

Table 4-6 – Estimated change in demand due to time-based control, January-February

Year	Average, MWh	Maximum, MWh
2016	376	555
2017	460	489
2018	462	598

Based on the typical profile*[31] of a customer with time-based control, the overall demand from electric heating during the night is estimated to be 4.4 times the demand during the hour of activation (starting at 22). This gives us a total demand of 1.7-2.0 GWh on average during the night. Table 4-7 shows the estimated increase in demand during peak hours if time-based control is removed. This has been calculated by assuming that the demand during the night would be evenly distributed throughout the day. The results show that the average increase is 70-85 MWh and the maximum increase is estimated to be 110 MWh.

[30] Source: TEM. Matkalla kohti joustavaa ja asiakaskeskeistä sähköjärjestelmää. 2017. Available at: http://julkaisut.valtioneuvosto.fi/bitstream/handle/10024/80792/TEMrap_38_2017_verkkojulkaisu.pdf

[31] Source: https://tinyurl.com/ya596w6f. Liite 1 - Aikamääreohje ja tyyppikäyrä (xls).

Table 4-7 – Estimated increase in demand during peak hours if time-based control is removed

Year	Average, MWh	Maximum, MWh
2016	69	102
2017	84	90
2018	85	110

Impact on demand and supply of flexibility

Removing the time-based control could potentially lead to more temperature-dependent load contributing to morning ramps if there are no alternative load control mechanisms in place, thus impacting on the demand for flexibility. However, if the nightly demand of these customers is spread more or less evenly, the impact can be seen only on absolute demand levels and not changes in demand from between hours.

The bigger impact from the removal is through increased incentives for customers to participate in demand response with retail contracts based on hourly wholesale prices. In addition to optimising against day/night network tariffs, the time-based control enables the customers to access a large share of the benefits for optimising hourly energy prices, because the automatic activation by DSOs happens in the evening. While optimally the activation would happen later during the night when the prices are the lowest on average, there are little incentives for these customers for services with more refined hour-to-hour load control schedules. Once more active control capabilities would be in place, there is also more potential to offer other flexibility services in addition to reacting to wholesale prices. The results in this section indicate a technical potential of 380-460 MW on average and up to 500-600 MW of controllable heating load during winter months.

4.3 -50% CHP production

Pöyry has evaluated the impact on supply of flexibility of removing 50% of the CHP production from the simulated hourly production profiles. It should be noted that this is a sensitivity analysis of the reduced production all else being equal, i.e. we have not re-modelled the hourly production profiles and considered that especially hydro capacity would re-optimise its dispatch.

Figure 4-15 represents the up-regulation duration curve for -50% CHP in 2025. Figure 4-16 represents the down-regulation duration curve for -50 % CHP in 2025. The sensitivity analysis indicates that the up-regulation potential is reduced significantly and down-regulation potential is increased. This is due to CHP production being replaced by hydro production from Finland and Sweden; increasing hydro production leaves less room for up-regulation potential and vice versa for down-regulation.

Figure 4-15 – Up-regulation potential (MW) duration curve with -50% CHP, 2025

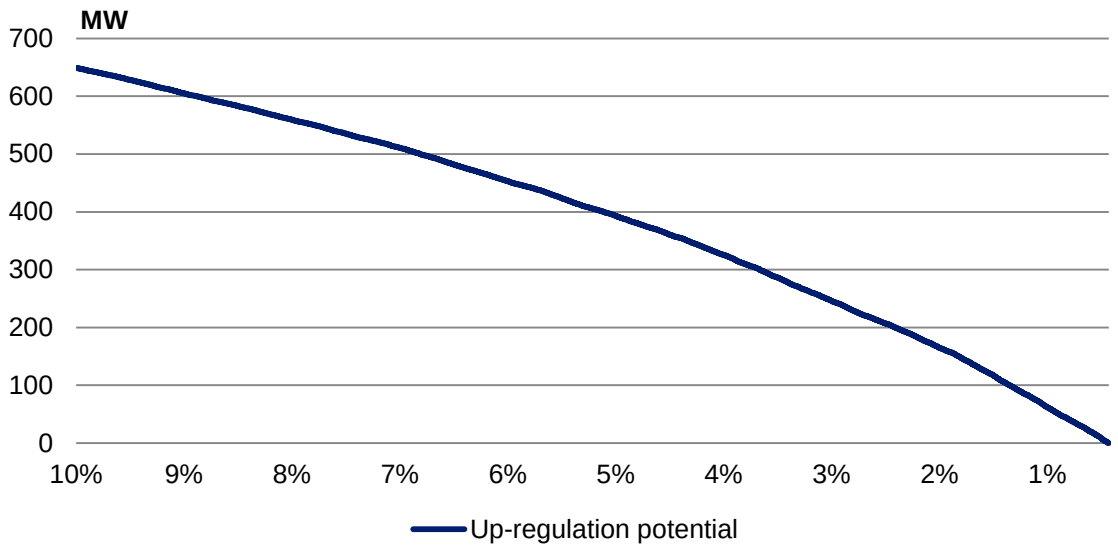
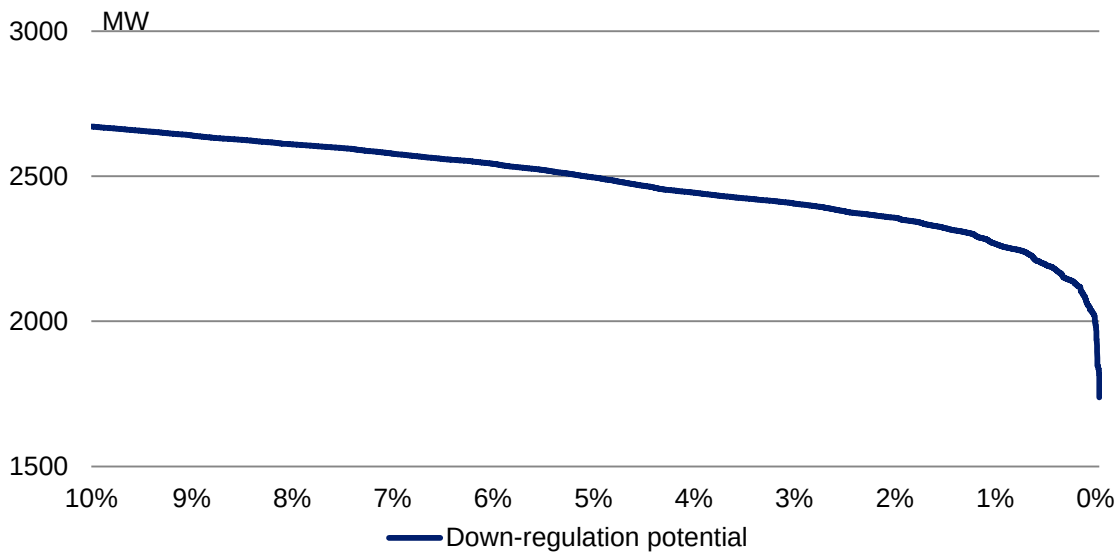


Figure 4-16 – Down-regulation potential (MW) duration curve with -50 CHP, 2025



Combining the up-regulation potential in this sensitivity case with demand for flexibility in 2025, yields the results presented in Table 4-8. The comparison is done in a similar fashion as in Section 3.6: supply of flexibility is approximated as a normal distribution. Comparing the results to those presented in the earlier section shows that -50% CHP has a large impact on probability of demand exceeding the supply of flexibility.

Table 4-8 – Combining supply and demand of flexibility, 2025, -50% CHP sensitivity

Supply – demand difference	Probability as number of hours per 10 years
0 MW	1.0
100 MW	2.5
200 MW	6.0
300 MW	13.5
400 MW	29.0
500 MW	59.0

Source: Pöyry analysis

5. CONCLUSIONS

Summary of the results

Under the assumed scenario, Pöyry's analysis indicates that insufficient availability of short-term flexibility is unlikely to occur when not accounting for power plant or interconnector outages. This analysis focused on the technical aspect of flexibility (MW) and did not look at the value of flexibility or cost of provision.

Demand for flexibility through changes in demand and wind production is expected to increase moderately by 2030.

- The increase in wind forecast error due to growth in wind power capacity is compensated by increased forecast accuracy.
- Increase in total forecast error - defined as the combination of wind and demand forecast errors - is compensated by negative correlation between the two errors.
- Demand remains the main contributor for hourly swings in net demand.
- The analysis does not include outages – a recent Nordic TSO study on capacity adequacy for 2025 estimated that shortages can occur in Finland on cold, non-windy days with power plant or interconnector outages.

The likelihood of supply of flexibility of being less than the demand for flexibility was found to be very low. The margin between supply and demand is less than 500 MW only 0.3 h/a in 2024 when the situation is the tightest.

- Supply of flexibility remains fairly stable until 2025 and increases between 2025 and 2030 with additional interconnector and nuclear capacity which releases interconnector capacity for balancing.
- Up-regulation potential is driven by available interconnector capacity for additional imports to Finland and Finnish hydro and CHP availability as well as industrial demand-side flexibility.
- Periods of low down-regulation potential are likely to occur during hours of high wind production and low hydro production. This is based on a conservative scenario where wind power is not providing down-regulation.
- This finding is based on one scenario of the future system development, other scenarios are possible.

The economic case for adopting flexible heating (and impact on demand profiles) by residential customers is heavily driven by the retail tariff structure: investment in flexible heat enablers (control systems) becomes economically feasible for the majority of customers by 2030 in the modelled scenarios for power-based tariffs and higher wholesale price volatility.

- Exposing households to hourly prices unlocks the value of residential flexibility and reduces the annual electricity bill.
- Charging the grid fees based on peak demand has the potential to flatten residential demand profile.
- Capacity based tariffs or increased wholesale price volatility are incentives to install flexible heating solutions.
- Flexible space and water heating brings benefits to households if no other forms of flexibility are applied (EV or battery). However, it is unclear how much the EV storage capacity would be used to optimise household retail bills or whether EV charging is optimised separately.
- If customers react to wholesale prices, they will have a lot of up-regulation potential during short periods of time, but mostly during the night. Optimising against capacity-based grid tariffs provides a smoother flexibility potential profile.

Implications for policy

Due to the uncertain nature of power system development, new sources of flexibility should be developed – the impact will be a more robust Finnish power system and potentially lower costs for consumers.

There are several possible future configurations of supply and demand of flexibility – it is prudent to ensure all flexibility measures are available, even though the scenario underlying this analysis shows little urgent need.

- Demand for flexibility will increase with more variable renewable generation entering the system and the rate of deployment is uncertain.
- Supply of flexibility comes from a variety of sources but the realisation is not certain e.g. CHP is replaced with heat-only boilers, new nuclear is delayed beyond 2030 etc.
- The role of the end-customers is still very much open: development of service offerings and cost of demand-side response technologies can have a large impact on the take-up rate and bring a lot of new residential flexibility to the market.

Supporting innovation and incorporating new technologies has the potential to bring down the cost of flexibility.

- European markets for flexibility - intraday and balancing - which are introduced in the coming years allows trading between market participants and provides TSOs access to balancing resources across Europe, but the net effect can bring up prices through increased competition for flexible Nordic resources.
- Demand side has significant unused potential, both on the industrial side and residential flexibility, according to interviews and analysis reported in this study.

Having a market design in place which allows for all sources of flexibility to compete in the market on equal terms provides a robust framework for different future scenarios. An efficient and competitive market incentivises investment and innovation where needed and minimises the need for short-term solutions that can lead to unwanted and potentially costly long-term consequences.

Table 5-1 lists the key market design changes for the coming years and their potential impact on demand and supply for flexibility. As a package, these changes aim to incentivise market participants to better balance their portfolios, thus reducing the demand for flexibility in the operational timeframe, and increase the supply of flexibility with the help of new products, larger markets and more accurate prices.

Table 5-1 – Key market design changes and their potential impact on demand and supply for flexibility in Finland

Market design change	Demand	Supply	Comments
Single price model for production and consumption	-	↑	▪ Also production imbalances that help the system imbalance are rewarded fully incentivising balancing actions outside the balancing markets
15-minute imbalance settlement period	↓	↑	▪ Market participants are incentivised to balance their portfolios within 15-min periods leading to potentially smaller system imbalances in the balancing timeframe ▪ Enables trading of 15-min products which could increase supply from e.g. demand-side
New Nordic balancing model based on ACE (Area Control Error)	↓	-	▪ Costs of imbalance are fully allocated to market participants who cause them, incentivising actors to trade themselves into balance leading to potentially smaller system imbalances in the balancing timeframe
Nordic aFRR (automatic frequency restoration reserve) capacity and energy market	-	↑	▪ aFRR procurement hours and volume will increase significantly thus providing additional value potential for flexible resources
Nordic mFRR (manual frequency restoration reserve) capacity market	-	↑	▪ Additional value for flexible resources from capacity payments
Introduction of pan-European market places (intraday and balancing)	-	↓↑	▪ Allows trading between market participants and provides TSOs access to balancing resources across Europe (increase supply of flexibility) ▪ Increased competition for flexible Nordic hydro resources to balance wind and solar variation in Central Europe (decrease supply of flexibility)

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Pöyry Management Consulting Oy
Jaakonkatu 3
01621 Vantaa
Finland

www.poyry.com