TAMPERE UNIVERSITY OF TECHNOLOGY

SAILA PERÄLÄ

NEW NETWORK TARIFFS: ECONOMICAL EFFECTS AND POSSIBILITIES FOR DEMAND RESPONSE

Master of Science Thesis

Examiner: Professor Pertti Järventausta
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ABSTRACT

TAMPERE UNIVERSITY OF TECHNOLOGY
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Future smart grids will bring possibilities and challenges for distribution system operators (DSO). The changing operation environment will also cause changes to the profitability of electricity distribution business unless the network tariffs are designed to correspond the requirements of smart grids. Renewable energy sources, distributed generation, micro grids and spot-pricing will cause the renovation of network tariffs. The yearly distributed energy will likely decrease because of distributed generation, but the need for power distribution capacity in the network and cost of investments will stay in around the same level as previously or increase. Therefore, it is justified to consider whether power based tariffs should also be available for domestic consumers, although power tariffs are mainly meant for industrial customers nowadays.

The aim of this thesis is to develop new network tariffs that could enable the implementation of demand response (DR) in electrically heated detached homes. New tariffs are the only means to implement DR, because without monetary reimbursement the customers do not have any interest to change their electricity consumption. So far, possibilities for DR and for different DR products have been researched mainly from retailers' perspective. Especially spot-priced retail tariffs have been piloted and researched broadly. However, there are conflicts between the interests of DSO and retailer and those have been reviewed in this thesis.

The new tariffs were designed using, for instance, AMR consumption data and elasticity model. The calculation method of peak power was enhanced, also consumption profiles were improved. The aim was to create tariffs that could decrease the peak power of customers, reduce cost of energy losses and reduce the investment needs. Six new tariffs were created. They encourage customers to change their consumption from on-peak hours to off-peak hours.

Demand response is a means of reaching European Union's target of 20 % energy efficiency by 2020, since network losses and peak power is reduced only by changing the time of use to the hours when is more capacity in the grid. Energy efficiency is a widely known term to the general public, but demand response is a lot more unknown, Therefore marketing of energy efficiency and DR should be coordinated. Customer education of smart grids is a major challenge. The increase in customers' interest and participation activity is very important, since without customer participation the benefit from smart grids decreases.

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Tulevaisuuden älykkäät sähköverkot tuovat tullessaan mahdollisuuksia, mutta myös haasteita sähköverkonhaltijoille. Muuttuva toimintaympäristö aiheuttaa muutoksia myös sähköverkkoliiketoiminnan kannattavuuteen, jollei tariffeja tulla suunnittelemaan älykkäiden sähköverkkojen vaatimalla tavalla. Uusiutuvat energiamuodot, hajautettu tuotanto, mikroverkot ja spot-hinnoittelu tulevat aiheuttamaan siirtotariffien uudistuksen. Asiakkaille siirretty vuosittainen energia tulee todennäköisesti laskemaan hajautetun tuotannon vuoksi, mutta tehotarve ja investoinnit tulevat säilymään samassa suuruusluokassa tai kasvavat. Tämän vuoksi on perusteltua ottaa harkintaan tällä hetkellä vain suurkuluttajille tarkoitettujen tehopohjaisten tariffien käyttöönotto myös pienasiakkailla.

Tämän opinnäytetyön tavoitteena on kehittää uudenlaisia sähkönsiirtotariffeja, jotka mahdollistaisivat kysyntäjouston sähkölämmitteisissä omakotitalokohteissa. Tähän mennessä mahdollisuuksia kysyntäjoustolle ja erilaisia tuotteita on tutkittu enimmäkseen vain sähkön myyntiyhtiön näkökulmasta. Erityisesti spot-hinnan mukaista ohjausta on tutkittu laajasti. Kuitenkaan sähköverkonhaltijan ja myyntiyhtiön intressit eivät aina kohtaa kysyntäjoustoasiassa, joten ristiriitoja on myös tarkasteltu tässä diplomityössä. Uudet tariffit ovat ainoa keino saada kysyntäjousto yleistymään, sillä ilman rahallista korvausta asiakkailla ei ole intressiä muuttaa tai antaa ohjattavaksi heidän sähkönkulutusta.

Uudet tariffit suunniteltiin AMR-kulutusdatan ja elastisuusmallin avulla. Myös huipputehon laskentamallia ja kuormituskäyriä parannettiin. Tavoitteena oli luoda tuotteita, jotka kulutusprofiilin muuttumisen seurauksena pienentävät asiakkaiden huipputehoa, vähentävät häviökustannuksia ja pienentävät investointitarvetta. Tuloksena saatiin kuusi uutta tariffia, jotka kannustavat asiakkaita muuttaa sähkönkulutusta siten, että kulutus vähenisi niiltä tunneilta, joilla sähköverkko on normaalia enemmän kuormitettuna.

Kysyntäjousto on yksi keino saavuttaa EU:n 20 %:n energiatehokkuustavoite vuoteen 2020 mennessä, sillä kulutuksen ajankohdan muuttaminen tunneille, jolloin verkossa on enemmän kapasiteettia, pienentää verkon häviöitä ja huipputehoa. Energiatehokkuus on suurelle yleisölle tuttu käsite, mutta kysyntäjousto on tuntemattomampi. Tämän vuoksi olisi järkevää alkaa markkinoida energiatehokkuutta ja kysyntäjoustoa saman palvelukonseptin alla. Tietoisuuden kasvattaminen älykkäistä sähköverkoista asiakkaille on yksi suuri haaste. Asiakkaiden kiinnostus ja osallistumishalukkuuden lisääminen on tärkeää, sillä ilman asiakkaiden aktiivista osallistumista hyöty älykkäistä sähköverkoista vähenee.

PREFACE

This Master of Science Thesis was carried out in Fortum Sähkönsiirto Oy as part of Smart Grids and Energy Markets (SGEM) project. The work was started in March 2011.

I would like to thank my supervisors from Fortum, Kari Koivuranta and Saara Peltonen, for giving me this interesting subject and for all the advice and support that they have given me during the work. Special thanks belong to Ville Koivuranta for excellent co-operation. Especially his IT skills were indispensable help to this work. I also want to thank my colleagues for giving me help and information related to this work. Moreover, their friendliness is the most important reason why I have enjoyed working in Fortum so much.

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I want to thank my family and grandparents for all the support that they have given me during my studies. I also want to thank my fellow students from all the memorable moments during the studies and free time, both in Tampere and in Bangkok. I want to particularly thank my dear friend Samu Kukkonen, since he has helped me in so many ways during the last six years.

Kiitos!

Espoo, Finland
November 2011

Saila Perälä

TABLE OF CONTENTS

ABBREVIATIONS AND NOTATION

AMI	Advanced Metering Infrastructure
AMM	Automatic Meter Management
AMR	Automatic Meter Reading
CC	Combined cycle
CCSP	Carbon Capture and Storage Program
CHP	Combined Heat and Power
CLEEN	Finnish Cluster for Energy and Environment
CPP	Critical peak pricing
DEA	Data Envelopment Analysis
DG	Distributed generation
DR	Demand response
DSM	Demand side management
DSO	Distribution System Operator
EDSO	The European Distribution System Operators for Smart Grids
EMV	Energy Market Authority
ESD	Fortum Electricity Solutions and Distribution division
EU	European Union
EV	Electric vehicle
FCEP	Future Combustion Engine Power Plants
FED	Fortum Espoo Distribution Oy
FSS	Fortum Sähkönsiirto Oy
HAN	Home Area Network
HV	High voltage
ISO	Independent System Operators
IVO	Imatran Voima
LM	Load management
LV	Low voltage
MMEA	Measurement, Monitoring and Environmental Efficiency Assessment
MV	Medium voltage
PLC	Power Line Communications
PCT	Programmable communicating thermostat
RTO	Regional Transmission Organization
RTP	Real-time pricing
SCR	Selective catalytic reduction
SFA	Stochastic Frontier Analysis
SGEM	Smart Grids and Energy Markets
StoNED	Stochastic Non-smooth Envelopment of Data
TOU	Time-of-Use

TSO	Transmission System Operator
WACC	Weighted Average Cost of Capital
VAT	Value added tax
VPP	Virtual Power Plant
$\boldsymbol{C}$	Estimated cost function
$\boldsymbol{C_E}$	Cost of equity
$\boldsymbol{C_i}$	System price of the hour i
$\boldsymbol{C_{old}}$	Price of hour *i* with old tariffs
$\boldsymbol{C_{old,average}}$	Average price of the inspection period
$\boldsymbol{C_{old,p}}$	Proportional price of hour *i* with old tariffs
$\boldsymbol{C_{new}}$	Price of hour *i* with new tariffs
$\boldsymbol{C_{new,average}}$	Average price of the inspection period
$\boldsymbol{C_{new,p}}$	Proportional price of hour *i* with new tariffs
$\boldsymbol{D}$	Market value of debt (net of cash)
$\boldsymbol{E}$	Market value of equity
$\boldsymbol{e}$	Price demand elasticity of a customer group, p.u.
$\boldsymbol{I}$	Current
$\boldsymbol{k}$, $\boldsymbol{l}$ **and** $\boldsymbol{m}$	Constants
$\boldsymbol{KAH_{i,t}}$	Realized calculatory disadvantage for the customers of DSO *i* caused by outages in electricity supply in year *t*
$\boldsymbol{k_{i2t}}$	Two-week index for customer *i* during hour *t*
$\boldsymbol{k_{it}}$	Hour index of customer *i* during hour *t*
$\boldsymbol{KOPEX_{i,t}}$	Controllable operational costs of DSO *i* in year t
$\boldsymbol{LP}$	Iliquidity premium
$\boldsymbol{N(x)}$	Price during hour x
$\boldsymbol{n}$	Number of customers
$\boldsymbol{P_{average}}$	Average power of the inspection period
$\boldsymbol{P_{FI}(x)}$	Power in Finland during hour x.
$\boldsymbol{P_{FI(max)}}$	Year's maximum power in Finland.
$\boldsymbol{P_{Finland,i}}$	Finland's power during hour *i*
$\boldsymbol{P_h}$	Active power losses
$\boldsymbol{P_i}$	Customer's hourly power
$\boldsymbol{P_{it}}$	Customer *i*'s power during hour x
$\boldsymbol{P_{limit}}$	Predetermined power limit that is set to software fuse
$\boldsymbol{P_{new}}$	Power during hour *i* with new tariffs
$\boldsymbol{P_{new,i}}$	Customer's power during hour *i* with new tariff
$\boldsymbol{P_{new,p}}$	Proportional power of hour *i* with new tariffs
$\boldsymbol{P_n(x)}$	Mean power of a customer during hour x
$\boldsymbol{P_{old}}$	Power during hour *i* with old tariffs

$\boldsymbol{P_{old,i}}$	Customer's power during hour *i* with old tariff
$\boldsymbol{P_{old,p}}$	Proportional power during hour *i* with old tariffs
$\boldsymbol{P_{Sec\ substation}(x)}$	Power of an average Finnish secondary substation network during hour x
$\boldsymbol{P_{Sec\ substation(max)}}$	Year's maximum power of an average Finnish secondary substation network.
$\boldsymbol{P_{Substation}\ (x)}$	Power of an average Finnish primary substation network during hour x.
$\boldsymbol{P_{Substation(max)}}$	Year's maximum power of an average Finnish substation network.
$\boldsymbol{P_{sum}(x)}$	Sum of customers' mean powers during hour x
$\boldsymbol{Q_h}$	Reactive power losses
$\boldsymbol{R}$	Resistance
$\boldsymbol{r_D}$	Debt cost of capital
$\boldsymbol{r_E}$	Equity cost of capital
$\boldsymbol{R_m}$	Average market returns
$\boldsymbol{R_r}$	Risk-free rate
$\boldsymbol{T}$	Temperature
$\boldsymbol{T_i}$	Temperature of hour *i*
$\boldsymbol{TL_i}$	With StoNED method estimated DSO-specific efficiency term TL of DSO *i*
$\boldsymbol{TOTEX_{i,t}}$	Actual efficiency costs of DSO *i* in year *t*
$\boldsymbol{u_i}$	The average inefficiency term of DSO *i*
$\boldsymbol{v_i}$	Random error term
$\boldsymbol{w}$	Constant
$\boldsymbol{W_i}$	Year energy of customer *i*
$\boldsymbol{X}$	Reactance
$\boldsymbol{X_i}$	DSO-specific efficiency improvement target of DSO *i*
$\boldsymbol{\overline{y}_i}$	The average output vector of DSO *i*
$\boldsymbol{z_a}$	Exceeding probability of variable *a* from standard deviation
$\boldsymbol{\overline{z}_i}$	The average underground cabling rate of DSO *i*
$\boldsymbol{\alpha}$	Proportional HV network losses and investment savings of peak power reduction.
$\boldsymbol{\beta}$	Proportional MV network losses and investment savings of peak power reduction.
$\boldsymbol{\beta_{asset}}$	Beta coefficient
$\boldsymbol{\gamma}$	Proportional LV network losses and investment savings of peak power reduction.
$\boldsymbol{\delta}$	The average cost effect of medium voltage network's (1-70 kV) underground cabling rate
$\boldsymbol{\varepsilon_i}$	Combined error term of inefficiency and random factors

$\boldsymbol{\sigma}$	Dispersion
$\boldsymbol{\sigma_n(x)}$	Nth customer's consumption's dispersion during hour x
$\boldsymbol{\sigma_{sum}(x)}$	Square root of quadratic sum of customers' consumption's dispersion during hour x
$\boldsymbol{\tau_c}$	Marginal corporate tax rate

1 INTRODUCTION

1.1 Fortum Oyj

Fortum Corporation was founded in 1998. It was created from the state owned Imatran Voima (IVO) and the listed company Neste Oyj. The Finnish State owned 50,76 % of the company's shares at the end of 2010. Fortum Corporation is divided into four divisions: Power, Heat, Russia and Electricity Solutions and Distribution, as depicted in figure 1.1. The Electricity Solutions and Distribution (ESD) division is divided into three business areas, Distribution, Electricity Sales & Marketing and New Business. Fortum ESD has operations in Sweden, Finland, Norway and Estonia. Fortum has heat production capacity in above-mentioned countries and in Poland, Great Britain, Russia and Latvia. Moreover, Fortum has power generation in Finland, Sweden, Russia and Great Britain. (Fortum Oyj 2011)

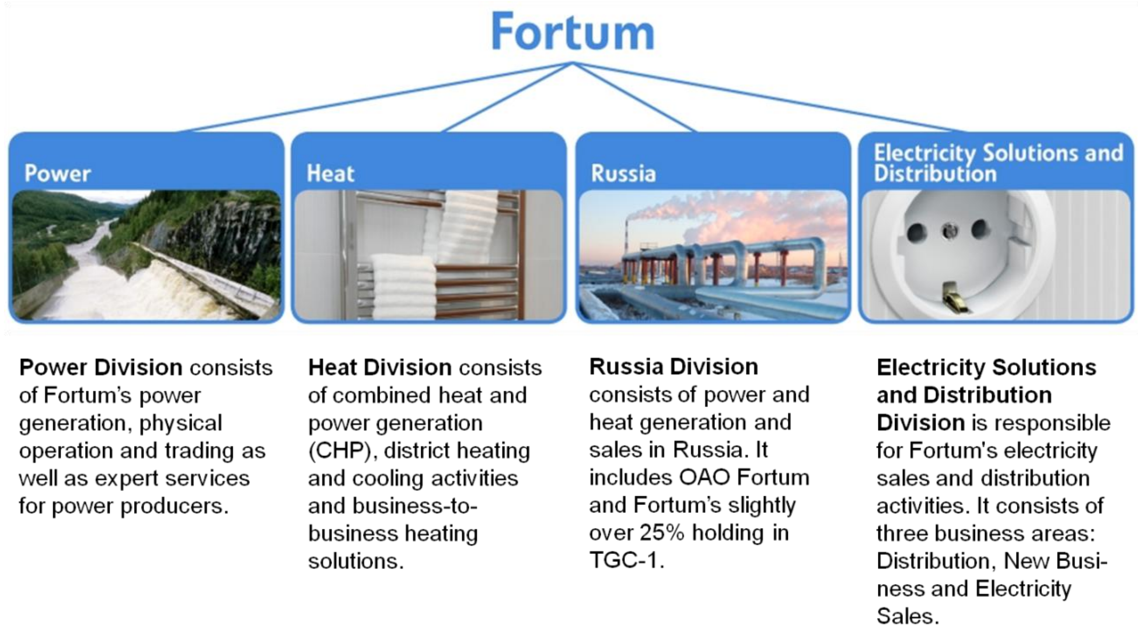

Figure 1.1. *Different divisions of Fortum and their business areas (Fortum Oyj 2011).*

Fortum ESD is the largest distribution company and the second largest electricity retailer in the Nordic countries, where Fortum ESD has 1,6 million electricity distribution customers and 1,2 million retail customers, as seen from figure 1.2. The distribution areas of Fortum in Finland are described in *appendix 1*. Fortum ESD owns and operates distribution and regional networks (0,4 kV – 220 kV). In addition, Fortum ESD is a leading seller of eco-labeled and CO2-free electricity. In 2010, the CO_2 emissions of electricity production were 84 g/kWh in Fortum's power plants in Europe, and in the whole of Fortum, including production in Russia, 189 g/kWh.

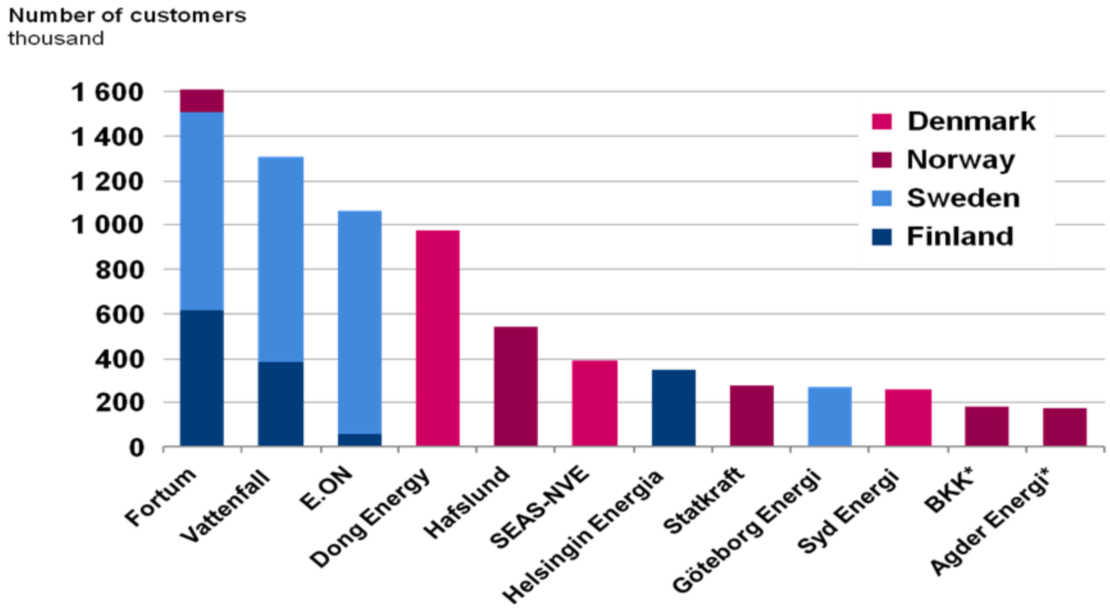

Figure 1.2. *The number of customers of Nordic distribution system operators in 2009. Statkraft's stake in BKK is 49,9 % and in Agder Energi 45,5 % (Fortum Oyj 2011).*

The operations of Fortum ESD Distribution have been divided into two distribution companies in Finland. The reason for two separate distribution price areas for Fortum's customers is because in 2006 Fortum acquired 99,8 % of the shares of E.ON Finland Oyj. Other business areas of E.ON Finland Oyj, except the distribution business were absorbed into Fortum Corporation in accordance with the business structure at that time. E.ON Finland Oyj administered the electricity network in Espoo and Joensuu regions. The distribution business of E.ON Finland Oyj was moved into a separate limited company, which is nowadays Fortum Espoo Distribution Oy. The reason for a separate distribution company was that the pricing in Espoo region was desired to be kept in similar pricing model as in E.ON Finland Oy. It was only possible by founding a separate company, because Fortum Sähkönsiirto Oy emphasized the basic charge and conversely, E.ON Finland Oy emphasized the variable distribution charge. (Haverinen 2011) The network regions of Fortum in Finland are presented in *appendix 1*. It is stated in Electricity Market Act that in geographically separate areas separate network tariffs have to be used. If the cost level and pricing principles of the parts of the distribution system holder's area of responsibility do not differ remarkably from each other, the electricity market authority may grant an exception for application of separate prices for distribution services.

1.2 The objectives and the scope of the thesis

The aim of this thesis is to design new distribution network tariffs, which would enable the implementation of demand response. The potential of tariff mechanism is researched and the consumption behavior of customers is analyzed with automatic meter reading (AMR) data. The AMR data consisted of one year period and the active power readings were measured once an hour. Data was collected from 270 consumption points. Most of them were detached houses with electrical heating. The customer group for which the new tariffs are designed is delimited to detached houses with electric heating. The reason is that they have much potential for demand response (DR) in Finland. The industrial customers are already responding to electricity market price or they have reserved for emergency control purposes (Jussila 2010). The impact of demand response is calculated with network calculation program. The impact of DR on losses and investment costs is calculated as a case study.

One key research question is how demand response can be utilized through network tariffs in order to influence energy efficiency drivers. Demand response is a cost effective and energy saving alternative to controllable power generation. Customers will not change their consumption behavior without proper incentives or reimbursement. Therefore, new tariffs are the only means to make demand response possible. One of the drivers for Smart Grids and demand response is EU's 2020 roadmap targets. The European Union member states are committed to reduce greenhouse gas emissions by 20 %, increase the share of renewable energy sources of EU's energy mix to 20 %, and to achieve the 20 % energy efficiency target by 2020. Moreover, another objective of Member States is to reduce greenhouse gas emissions by 80-95 % compared to the level of 1990 by 2050. (European Commission 2011)

Demand response and customer participation is one of the most important research areas in Smart Grids. Figure 1.3 describes some Smart Grid research themes that are going on in EDSO (The European Distribution System Operators for Smart Grids). EDSO is an international non-profit association committed to the development of Smart Grids in Europe.

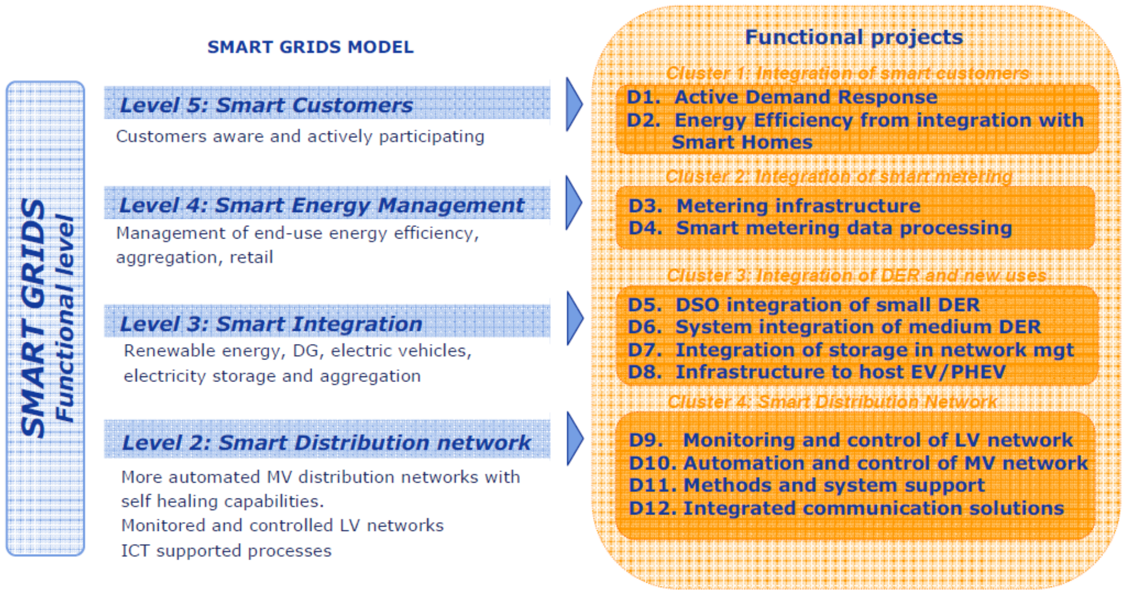

Figure 1.3. *EDSO's research projects for Smart Grids (EEGI 2010).*

1.3 Smart Grids and Energy Markets research program

The Finnish Cluster for Energy and Environment (CLEEN) manages four on-going research programs: Carbon Capture and Storage Program (CCSP), Future Combustion Engine Power Plants (FCEP), Measurement, Monitoring and Environmental Efficiency Assessment (MMEA) and Smart Grids and Energy Markets (SGEM). Fortum is participating in the SGEM research program, which started in September 2009 and will last until 2014. CLEEN Ltd's operation as the energy and environment strategic centre for science, technology and innovation is based on the common vision and strategic research agenda defined by the centre's owners, i.e. companies and research institutes. (CLEEN 2011)The research themes of SGEM in second funding period are:

- Drivers and scenarios
- Future infrastructure: low voltage (LV), medium voltage (MV) and high voltage (HV)
- Active resources: customer gateway and distributed resources
- Intelligent management and operation
- Energy markets and business models

This thesis is part of second funding period's Work Package 4: Active customer, customer interface and ICT. The task is 4.1 Customer behavior, trust, and privacy. The deliverable number of this thesis is 4.1.8. Role of demand response through new features of AMI (advanced metering infrastructure) interfaces and development of capacity based tariffs.

1.4 Smart Grids

The European Technology Platform (2010) defines the concept of Smart Grids as an electricity network that can intelligently integrate the actions of all users connected to it – generators, consumers and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies. The vision of Smart Grids is to

- Provide a user-centric approach and allow new services to enter into the market
- Establish innovation as an economical driver for the electricity networks renewal
- Maintain security of supply, ensure integration and interoperability
- Provide accessibility to a liberalized market and foster competition
- Enable distributed generation and utilization of renewable energy sources
- Ensure best use of central generation
- Consider approximately the impact of environmental limitations
- Enable demand side participation (demand side response, demand side management)
- Inform the political and regulatory aspects
- Consider the societal aspects

The need for Smart Grids comes from the EU target to reduce carbon dioxide emissions, increase the utilization of renewable energy and increase energy efficiency. The integration of low carbon technologies is not possible without network upgrade. Distribution networks will have to be capable of integrating large-scale distributed generation (DG), including residential micro generation. Smart Grids are going to face many challenges, for example, the communication system will have high requirements and the demand side must play a more active role in the operation of the system. In addition, the electricity networks have to have enough transmission capacity, and to be able to integrate intermittent generation and to be able to operate harmoniously with smaller scale generation. Some of the most important Smart Grid solutions are presented in table 1.1. and in figure 1.4. Moreover, the electric vehicles (EV) are going to cause a major challenge for the future electricity networks. (European Technology Platform 2010)

Table 1.1. *Comparison of traditional distribution network and Smart Grid (European Commission 2006, Heino 2009).*

Traditional distribution network	Smart Grid
Non or one-way communication	Two-way communication
Centralized generation	DG (renewable) + centralized generation
Blackouts and failures	Adaptive and islanding
Electromechanical	Digital
Few sensors	Monitors and sensors throughout
Blind	Self-monitoring
Manual restoration	Semi-automated restoration and self-healing
Check equipment manually	Monitor equipment remotely
One-way power flow	Two-way power flow

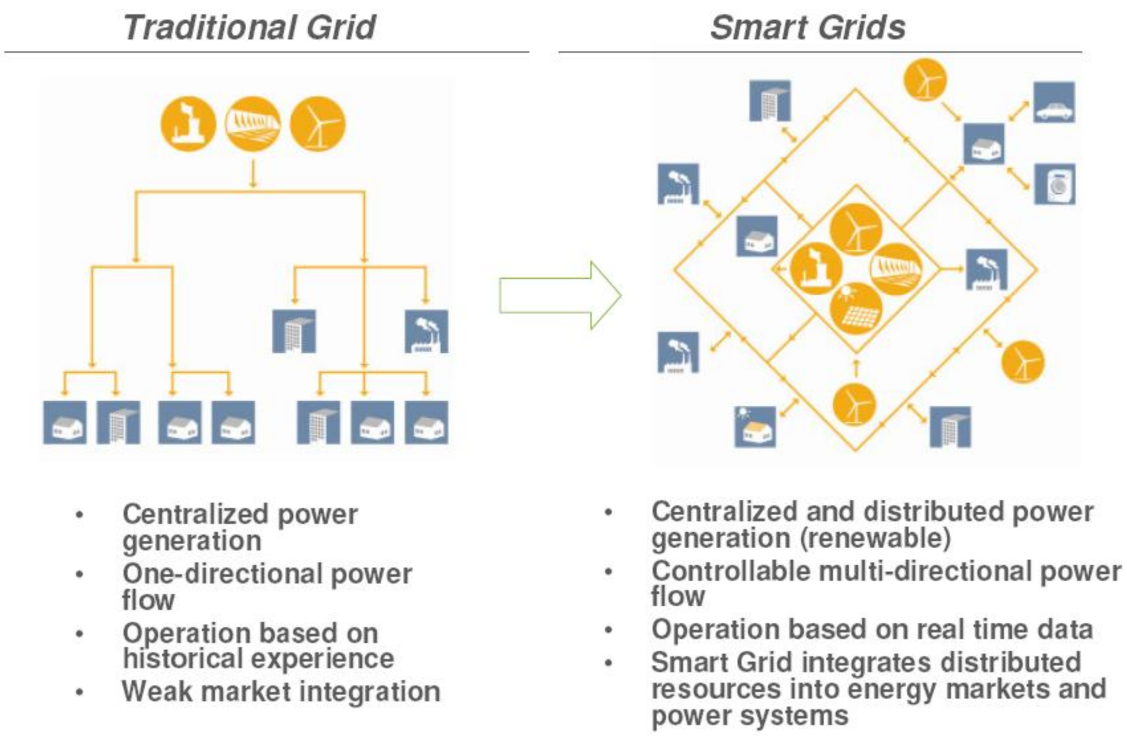

Figure 1.4. *SGEM vision of Smart Grids (Kroman 2009).*

The network's ageing will be a problem in Finnish rural area during next few decades. In addition, the climate change is going to cause difficulties, especially for the overhead lines in the forests. At the same time, higher reliability of networks is needed within reasonable cost, remembering that the population in rural areas is predicted to decrease. In June and July 2010, strong storms caused power outages for tens of thousands of customers in Finland. Then over 8,1 million cubic meters of growing timber was destroyed. The storms increased the average time of outage per customer last year. One reason is that it took longer than normal to remove the trees that were fallen on the overhead lines was because the storm devastation was very vast. The vision to respond to future challenges is depicted in figure 1.5. It contains several technical solutions. For example the underground cable rate is going to grow, communication and network automation is going to enhance, network islanding will be introduced and new network solutions based on power electronics are going to improve power quality and profitability.

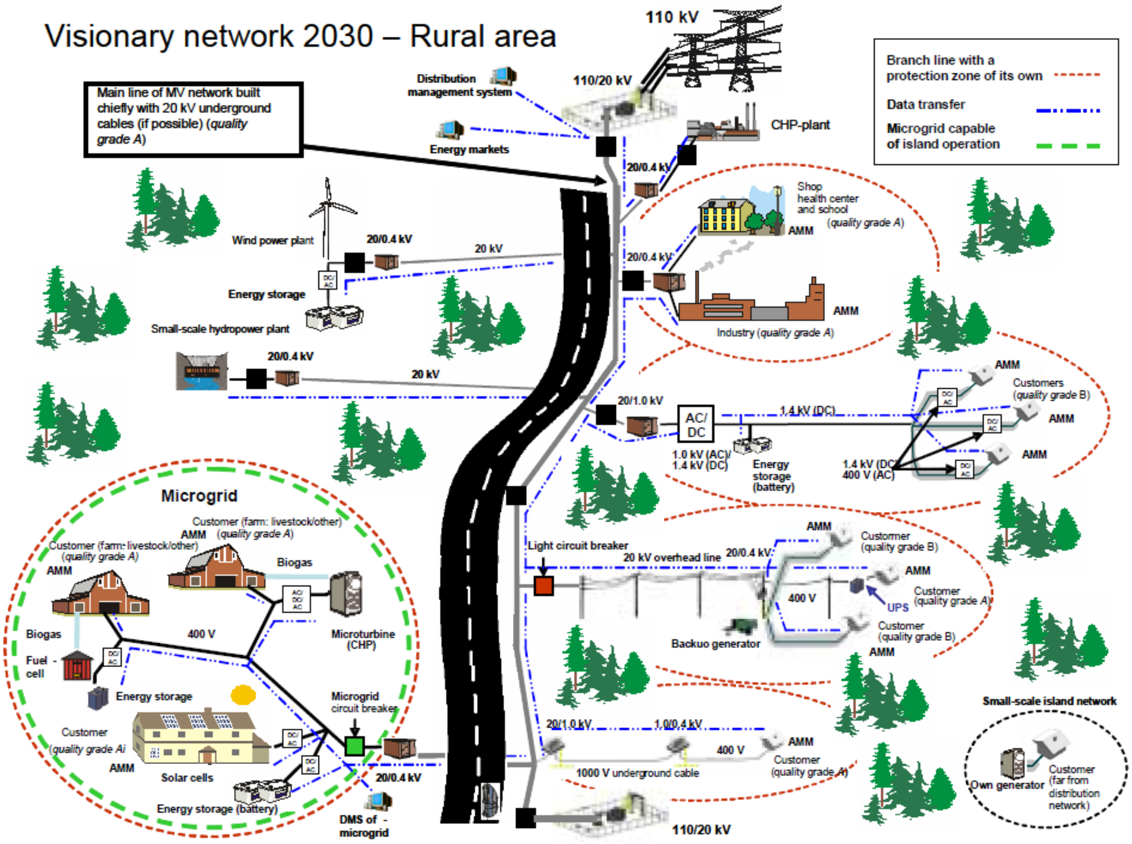

Figure 1.5. Rural area's visionary network in 2030 (Kumpulainen et al. 2006).

Energy storages are an essential part of Smart Grids, since electricity storages will be involved in enabling the use of microgrids. Moreover, electricity storages will allow a larger share of uncontrollable energy sources. Smart Grids will combine the functions of DG, electricity storages, AMI and distribution automation, so that the benefit is higher than in separate usage. The building of Smart Grids will take several decades, because the life cycle of networks is very long. (Jussila 2010) It should also be remembered that Smart Grids are not "Super Grids" or smart metering, and there will not be any rollout of Smart Grids, because the rollout is continuously occurring. (Peltonen 2011)

2 NETWORK TARIFFS

2.1 Electrical network business

Electrical network business has various expectations from different interest groups. The customers expect reasonable and non-discriminative prices and good quality electricity. In addition, the level of customer service has to be good. Society expects that customers are treated equally and that distribution system operators (DSOs) construct and maintain adequate infrastructure. The shareholders want that competitiveness improves, expected yield realizes and that the economic value of business increases. (Partanen et al. 2010) Smart grids, increasing energy efficiency and aging network infrastructure causes economical challenges for DSOs. Regulation model has to ensure stable business environment, because electrical network business is a very capital-intensive sector. For example, the payback period of investments is very long, so the allowed rate of return has to be reasonable. The regulation model should not only stress the interests of society and customers, but also the interests of DSOs so that the future network investments can be done.

2.1.1 Regulation of electricity distribution business in Finland

Electricity network business is licensed monopoly business, therefore the companies do not have incentives from free market competition to operate cost effectively and have reasonable prices. Regulation ensures that the customers are treated fairly and charged reasonably, and that the operation is cost effective. Energy Market Authority (EMV) determines the principles of regulation. From 1995 until 2004 the regulation of network business was inspected afterwards. The first regulation period was 2005 – 2007 and the second 2008 – 2011. The length of a regulation period is four years. The third regulation period will begin on January 1, 2012 and will end on December 31, 2015.

During the regulation periods, EMV calculates and informs yearly the realized and the amount of allowed reasonable return. After the ending of regulation periods EMV informs all DSOs separately how much the accumulated return exceeds or is below the allowed rate of return. If the accumulated return is bigger than the allowed return, DSO is obliged to lower the network tariff in the following regulation period. (Pantti 2010) After the third regulation period, EMV will make the regulation decision before the end of 2016. It confirms the DSO's actual adjusted return after corporation tax reduction, accrued during the regulation period, and the sum how much the return has exceeded or fallen below the allowed reasonable return on DSO's network operations during the third regulation period. In the calculation, EMV will add the actual returns accrued during each year of the regulation period after imputed corporation tax and deduct from the total sum of reasonable return on the DSO's network operations after imputed corporation tax in the corresponding years.

The windfall profit or loss from the second regulation period is taken into account in the regulation decision, whereas the windfall profit or loss from the first regulation period is not taken into account anymore in the third regulation period, although the windfall loss would not have been equalized during the second regulation period. Table 2.1 shows the simple version of principles of determining the allowed reasonable return on the DSO's network operations.

Table 2.1. *The regulation principles of DSO's reasonable network business pricing in the third regulation period* (EMV 2011b)

+ The sum of actual adjusted return after corporation tax reduction from the third regulatory period (2012-2015) – The sum of allowed reasonable return after corporation tax reduction from the third regulatory period (2012-2015) + The accumulated surplus (+) or deficit (–) after corporation tax reduction from the second regulatory period (2008-2011).
= The accumulated surplus (+) or deficit (–) from the third regulatory period (2012-2015)

2.1.2 Determination of allowed rate of return

EMV uses the Weighted Average Cost of Capital (WACC) model in determination of reasonable return on capital for adjusted invested capital of network operation in the third regulatory period.

$$WACC_{after-tax} = \frac{E}{E+D} r_E + \frac{D}{E+D} r_D (1 - \tau_c) \qquad (1)$$

In this formula,
E = market value of equity
D = interest bearing debts
τ_c = marginal corporate tax rate
r_E = equity cost of capital
r_D = debt cost of capital

The cost of equity is estimated by using Capital Asset Pricing Model (CAPM). It describes the dependency between the returns requirement on a share involving risk and the risk itself. Cost of equity is determined as follows:

$$C_E = R_r + \beta_{asset} * (R_m - R_r) + LP \quad (2)$$

Where

C_E = Cost of equity
R_r = Risk-free rate
β_{asset} = Beta coefficient
R_m = Average market returns
$R_m - R_r$ = Market risk premium
LP = Illiquidity premium

The parameters for calculating reasonable rate of return have been changed for the third regulatory period and are shown in table 2.2. The principles how the allowed reasonable return and adjusted actual return are calculated is shown in figure 2.1.

Table 2.2. *The calculation parameters for reasonable rate of return in the third regulatory period (EMV 2011b).*

Parameter	**Applied value (subject to corporate tax)**	**Applied value (others)**
Risk-free rate	The interest on a ten-year Finnish government bond completed in May of the previous year, deducted with inflation component	The interest on a ten-year Finnish government bond completed in May of the previous year, deducted with inflation component
Beta asset	0,4	0,4
Beta equity	0,527	0,571
Market risk premium	5 %	5 %
Inflation component	1 %	1 %
Illiquidity premium	0,5 %	0,5 %
Fixed capital structure (ratio of interest-bearing debts to equity)	30/70	30/70
Tax rate	26 %	0%
Cost of interest-bearing debts	risk-free rate + the risk premium of debts 1 %	risk-free rate + the risk premium of debts 1 %

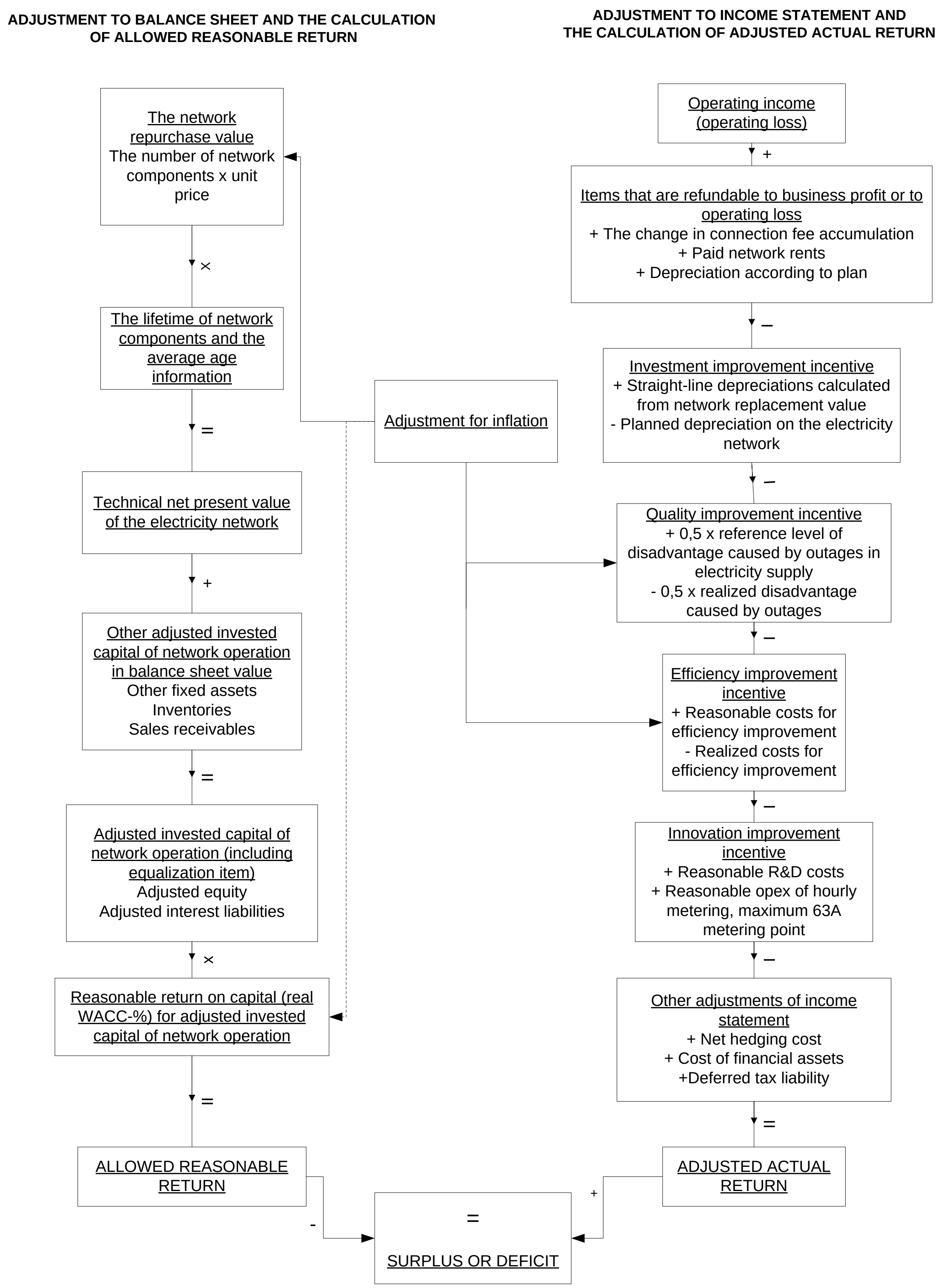

Figure 2.1. *The central methods and principles of the third regulation period 2012–2015. Adjusted from (EMV 2011b).*

The quality improvement incentive has more significance in the new regulation model than in the previous period. It encourages DSOs to plan their network so that the number and duration of outages would decrease. A target of regulation model is to make DSO's operations more efficient. The efficiency improvement target consists of a common efficiency target, a company-specific efficiency improvement target and DSO-specific efficiency term. A common efficiency target determines the growth possibility of electricity network industry. DSO's common efficiency target is 2,06 % in a year. The aim of common efficiency target is to encourage all DSOs to make their operations more efficient according to common productivity development. The aim of company-specific efficiency target is to encourage the DSOs that have not succeeded in efficiency measurements to reach the level of efficient operations. The DSO specific efficiency improvement target contains both the common efficiency target and the company-specific efficiency target. EMV ordered Sigma-Hat Economics Oy to design an efficiency measurement model. Sigma-Hat Economics Oy created a Stochastic Non-smooth Envelopment of Data (StoNED) method, which is used in the new regulation model to measure efficiency and to determine the efficiency improvement target. In previous inspection period in the determination of operation's efficiency figure was used the average of two figures, which were calculated with Data Envelopment Analysis (DEA) method and Stochastic Frontier Analysis (SFA) method. The principles of StoNED method are determined shortly below. More specific information can be found from EMV's decision (EMV 2011b).

Company-specific efficiency improvement target is determined as follows.

$$\overline{TOTEX_i} = C(\overline{y}_i) * e^{(\delta \overline{z}_i + \varepsilon_i)} = C(\overline{y}_i) * e^{(\delta \overline{z}_i + u_i + v_i)} \qquad (3)$$

Where

$\overline{TOTEX_i}$ = the average efficiency improvement cost of DSO *i* in 2005-2010

C = estimated cost function

$\overline{y}_i$ = the average output vector of DSO *i* in 2005-2010. The output variables are the amount of transmitted energy and the production for own use $\overline{y}_1$, the total length of the electricity network $\overline{y}_2$, the number of customers $\overline{y}_3$.

δ = parameter describing the average cost effect of medium voltage network's (1–70 kV) underground cabling rate

$\overline{z}_i$ = the average underground cabling rate of DSO *i* in 2005-2010

$\varepsilon_i = u_i + v_i$ = combined error term of inefficiency and random factors

u_i = the average inefficiency term of DSO *i* in 2005-2010

v_i = a random error term

DSO-specific efficiency term

$$X_i = 1 - \sqrt[8]{TL_i} * (1 - 2{,}06\,\%) \qquad (4)$$

Where

X_i= the DSO-specific efficiency improvement target of DSO i

TL_i = with StoNED method estimated DSO-specific efficiency term TL of DSO *i*

$(1 - 2{,}06\,\%)$ = describes the cost efficiency need in eight-year transition period, which is in accordance with common efficiency target.

The 8th root used in formula (4) becomes from the length of used transition period

Actual efficiency costs

$$TOTEX_{i,t} = KOPEX_{i,t} + 0{,}5 * KAH_{i,t} \quad (5)$$

Where

$TOTEX_{i,t}$= the actual efficiency costs of DSO *i* in year *t*, euros

$KOPEX_{i,t}$ = the controllable operational costs of DSO *i* in year t, euros

$KAH_{i,t}$ = the realized calculatory disadvantage for the customers of DSO *i* caused by outages in electricity supply in year *t*, euros

2.1.3 Principles and requirements for tariff design

Electricity Market Act determines the principles and obligations for network business and network tariff design in Finland. Companies that operate in electricity market business shall provide electricity supply services and contribute to efficient electricity usage and energy saving in their operations and as well in those of their customers. Electrical network business can be carried on only if the Energy Market Authority has given a license for operation (electricity system license). The DSO's geographical area of responsibility is determined in the license given by EMV. The DSO must maintain, operate and develop their network and connections to other networks in accordance with its customers' moderate needs. In addition, the DSO must provide high-standard electricity to its customers. The DSO has to offer distribution services with moderate compensation within the limits of transmission capacity for customers who need it in the DSO's distribution region. Moreover, the DSO has to provide the measurement of delivered electricity appropriately. A customer has to pay the DSO moderate measurement costs that they have caused. (Electricity Market Act 17.3.1995/386)

The DSO must publish the prices and the sales terms of network service, and their criteria. They must be equitable and non-discriminative to all network users. Pricing of network services must be reasonable. Furthermore, the DSO must publish economic ratios that depict the efficiency, quality and profitability of system operation. The DSO shall not collect a fee for registration, balance settlement or other performances that are related to changing the electricity retailer. The DSO shall not either collect a fee for meter reading when the customer changes the electricity retailer, if the electricity retailer was changed at least one year ago previous time. (Electricity Market Act 17.3.1995/386)

Nodal pricing defines that the DSO shall provide prerequisites permitting the customer to have rights, in return for appropriate payment, to use the whole country's electricity system from its connection point, excluding foreign connections. The distribution price shall not be dependent on the geographical location of the customer within the system operator's area of responsibility.(Electricity Market Act 17.3.1995/386) The purpose of nodal pricing is that the pricing is equitable and cost correlative. On the other hand, if the pricing was cost correlative, the customers who cause more expenses would have to pay higher tariffs. Then each customer would have individual network tariffs and it is in contradiction with principle of equality.

2.2 Principles of tariff structure

Distribution network tariffs consist of basic charge, energy-based charge and power charge. Normally, the network tariff of household customer consists of basic charge and energy distribution. The basic charge is fixed or dependent on the main fuse size. The energy-based part of distribution charge may vary between the time of day and between the seasons. Power distribution tariffs also contain active power charge and reactive power charge. It is essential in tariff design to determine the proportion of basic charge to energy-based charges. The fixed costs of rural networks are high, because the length of network per customer is high. Therefore, it is likely that the pricing is stressed on basic charge if there is great number of rural distribution network in the distribution region of a DSO. In that way, the cost correlation of pricing is higher and more non-discriminative. (Pantti 2010) It is not possible for the customers to put distribution price out to tender, whereas it is possible to tender the energy retail price.

The cost components of electricity price are network costs, wholesale costs, retail costs, electricity tax and value added tax (VAT). The focus is on network tariffs in this thesis. The operation of the DSO and retailer are unbundled in Finland by the Electricity Market Law (Electricity Market Act 17.3.1995/386). In Finland, EMV regulates the monopoly business of DSOs. The reason for monopoly business is that the construction and operating of parallel networks is not reasonable economically. The wholesale price of electrical energy forms in Nord Pool Spot electrical energy market. Figure 2.2 is a sketch of present energy and money flow in electricity business. This traditional flow of money and electrical energy is going to be changed when consumers will have possibility to be more active market players by feeding their production into the grid. Electricity is mainly generated in big power plants nowadays, from where it is transmitted through transmission network and distribution network to a customer. Then consumers pay for their DSO and retailer. The retailer accounts for producers and to the power exchange. Moreover, Transmission system operator (TSO) charges the DSO of grid usage.

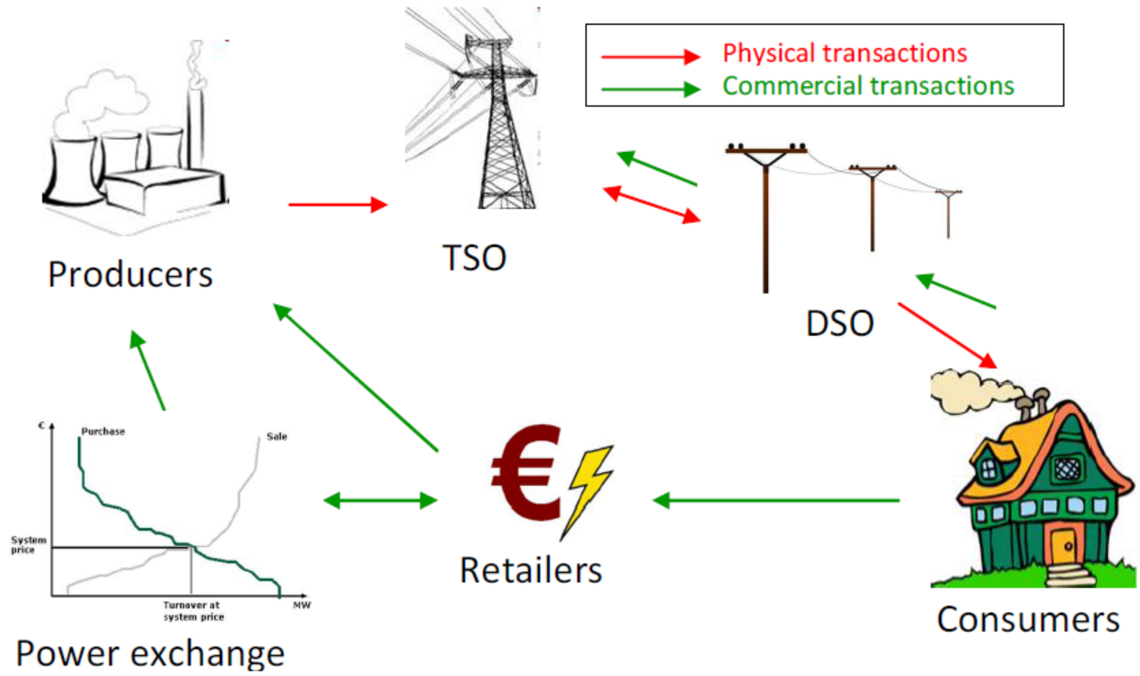

Figure 2.2. *Actors in the electricity business. Modified from (Back et al. 2011).*

The taxation of electrical energy consists of VAT and electricity tax. VAT is also charged of electricity tax. There are two electricity tax classes in Finland. Since January 1, 2011, the tax class 1 is 2,0947 c/kWh and in class 2 it is 0,8647 c/kWh, including VAT. Domestic customers, public sector, agricultural entrepreneurs and service sector customers belong to tax class 1. Companies that are industrial manufacturers and professional greenhouse cultivation customers are eligible to lower tax class 2. The classification of suitable manufacturing is determined in law. If a customer is eligible for the lower tax class, they have to send an assurance in writing to the DSO. The electricity tax is energy-based, therefore it will cause more expenses to customers who consume electricity much. It explains why the proportion of electricity tax of overall electricity price is higher for household customers with electric heating than for household customers without electric heating. The difference between the formation of electricity price of household customers and household customers with electricity heating can be seen by comparing figure 2.3 and figure 2.4.

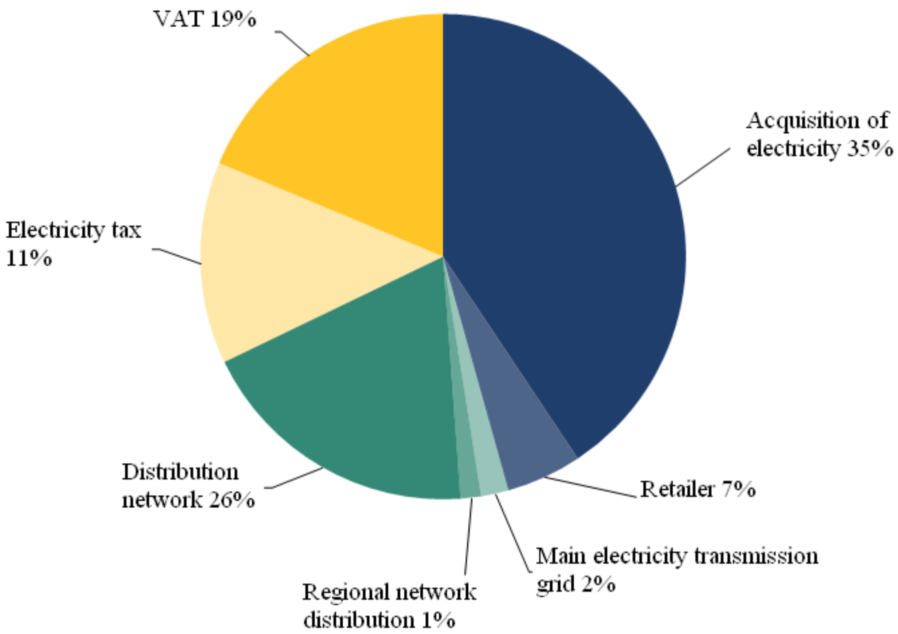

Figure 2.3. *The formation of the electricity price of household consumers. The average sum is 15,23 c/kWh on March 1, 2011. Modified from (EMV 2011a).*

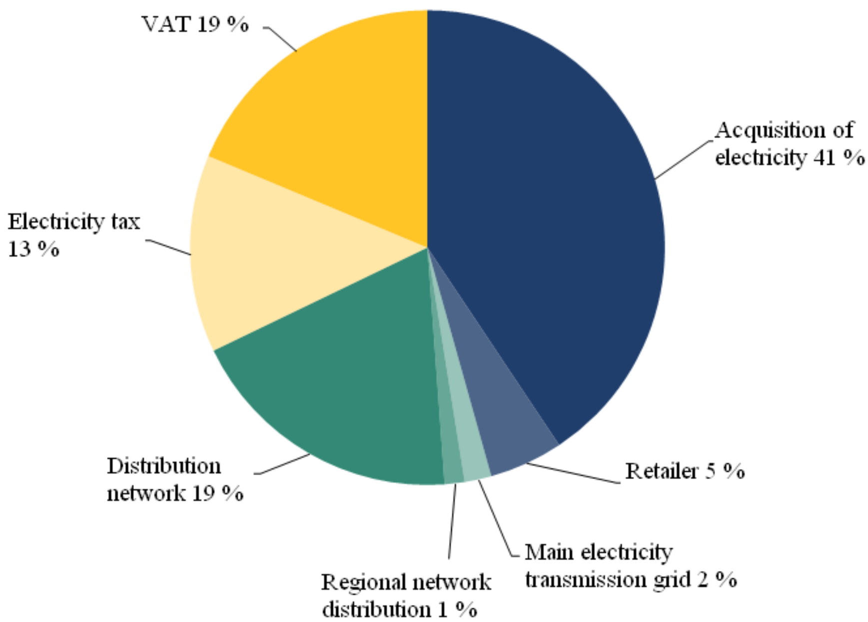

Figure 2.4. *The formation of the electricity price of household consumers with electric heating. The average sum is 12,66 c/kWh on March 1, 2011. Modified from (EMV 2011a).*

2.2.1 Basic charge

The basic charge is a fixed monthly payment. The basic charge can be based on the main fuse size of a connection point or it can be the same for all customers who have same network tariff. When the basic charge is well determined, the matching principle realizes in the best possible way. For example, the grid investment is notably more expensive for 200 A interfaces than for 25 A interfaces. The higher the main fuse size is, the bigger the basic charge, and therefore it prods customers into choosing smaller fuse size. For this reason, the network will be rated for smaller capacity and it will possibly result in reduced investment costs. Nowadays the main fuse size is often overrated, because some customers might have high peak powers although their total energy consumption in a year can be small, or they estimate their peak loads to be too high. The AMR devices will help choosing the best fuse size for customers, since hourly measurement data will help in choosing the real need of power and fuse size. Basic charge is good for distribution companies, because it means predictable income and balances seasonal billing.

The drawback of high basic charge is that it does not motivate customers to save energy, because the network fee is almost in a similar level regardless the consumption amount per month. The basic charge covers the expenses of administration, part of investment costs, customer service and invoicing. Some Finnish network companies charge for metering separately, whereas the metering cost is included in basic charge in Fortum's tariffs.

2.2.2 Distribution charge

Distribution charge is an energy-based fee, which unit is €/kWh. The costs of energy usage are allocated to distribution charge. The distribution charge can be considered as transfer of income from large customers to small customers within a similar tariff class, because without energy-based charge the basic charge would be very high for small customers. The amount of distribution charge can vary depending on time of use. The purpose of time-of-use tariffs is to prod customers into using electricity when the total consumption is lower. (Pantti 2010) The distribution charge covers the expenses of invested capital, maintenance and part of investment costs.

2.2.3 Power charge

Power charge is meant for the customers who consume electricity significantly. Active power usage has so far mostly been measured from customers who have power distribution tariff. The active power usage of customers except power tariff customers was previously only estimated by fuse size and consumption profiles. The automatic meter readers enable the exact power measurement also from small customers. Power charge is advantageous, because it in some level reduces the risk of grid overloading and the need to reinforce the grid.

2.2.4 Reactive power charge

The transmission of reactive power reserves transfer capacity and increases active and reactive power losses. The customers who have the power distribution tariff are measured and charged of reactive power consumption. Almost all customers consume reactive power, but it is only economical to measure of Power Distribution tariff customers. The reactive power charge encourages customers to compensate their reactive power in the cases it is economical. For Fortum's customers with Power Distribution tariff the free proportion of reactive power is 20 % of the charged peak active power.

2.3 Network tariffs in FSS and FED

A key question is which percentage of costs is allocated to basic charge and how much is allocated to energy-based fee. If it is considered purely electrotechnically, most of the costs are fixed (metering, invoicing, administration, operational expenses and financing costs). So they are not depending on the amount of distributed energy. Therefore, they should be allocated to fixed basic charge. Only the costs of losses and transmission network fees are dependent on the amount of distributed energy. The cost pools and cost allocation is depicted in figure 2.5.

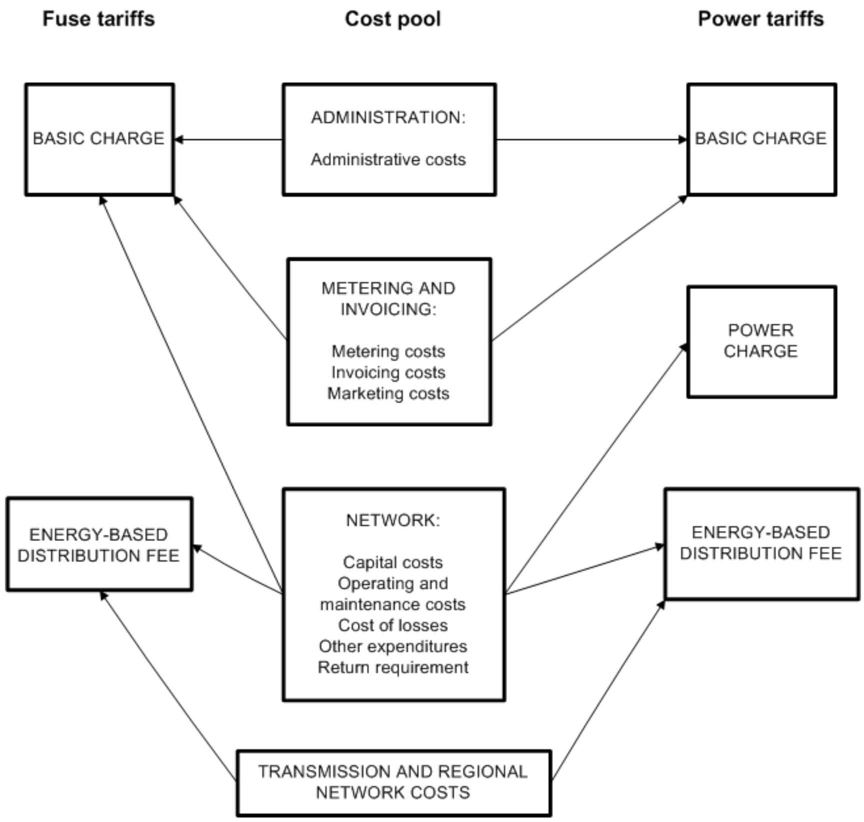

Figure 2.5. *The cost pools of electricity distribution and the principles of cost allocation to payment components in Fortum. Modified from (Partanen et al. 2010).*

The impact of single customer on investment costs is clearly verifiable in low voltage network, so its caused expenses are allocated to basic charge. The investment needs for regional network caused by a certain customer are difficult to verify. Therefore, the costs are allocated to energy-based distribution fee. Half of the network costs were allocated to distribution fee and another half to basic charge in Fortum's tariffs in 1990s. After 1990s, there have been many company acquisitions, so the ratio has been changed a bit due to different price system in acquired companies. The acquisition of E.ON Finland in 2006 caused that Fortum has had two separate price areas from that on. FSS allocates more network costs to basic charge than to distribution fee, whereas FED allocates more network costs to distribution fee than to basic charge. The Fortum's tariff names in the following chapters are not official translations. All the present tariffs are in *appendix 2* and *3*.

2.3.1 Fortum General Distribution tariff

Fortum General Distribution tariff is suitable for electricity customers, who consume most of their energy in daytime and their total energy consumption is not much higher than 10 000 kWh in a year. The basic charge in Fortum Espoo Distribution Oy region is the same for all customers in Fortum General Distribution tariff, whereas in Fortum Sähkönsiirto Oy region the basic charge is depending on the main fuse size.

There is also temporary connection contract available for customers who need temporary distribution. The contract is automatically done for two years period, but the length can be negotiated. It can be purchased, for instance, to construction sites. The tariff is Fortum General Distribution and the basic charge is debited double the amount. Customers who purchase temporary connection contract are exempt from connection fees.

2.3.2 Fortum Nighttime Distribution tariff

The Nighttime Distribution tariff is economical and reasonable for medium-size customers that can consume significant amount of their electric loads at nighttime and their yearly consumption is over 10 000 kWh. A hot-water tank is a good example of load that can be used at nighttime. The purpose of having lower tariff at nighttime is to prod customers into consuming electricity when the overall loading in the system is the smallest, hence it will reduce power peaks at daytime. A more even consumption profile will reduce network losses, the network is used more efficiently and investment costs are reduced. Drawback of Nighttime Distribution tariff is that there exists a notable power peak in the network when all controllable loads are switched on at the same time at 10 pm. The loads are mostly hot-water tanks. Automatic meter management (AMM) will enable the staggering to become easier in future. In FSS region, the electricity heating loads of household customers will be turned on in stages between 10 and 12 pm and in FED between 09 and 12pm. All the remotely controlled loads are switched off at 7 am. The load control time is chosen randomly and it will be in use instantly after AMR meter installation. In Espoo area, staggering has been used for all household customers who have Nighttime Distribution tariff already for several years.

The distribution price is higher from Monday to Saturday between 7 am and 9 pm in FED. In FSS the equivalent times are from Monday to Sunday between 7 am and 10 pm. An exception is that if there is no AMR, the day tariff is from 8 am to 11 pm in summer time. The basic charge is the same for all FED customers but in FSS it depends on the main fuse size.

2.3.3 Fortum Season Distribution tariff

Fortum Season Distribution is suitable for customers who have controllable loads and they can use alternative form of heating at daytime from November to March. The distribution charge is higher between 1.11.–31.3. In FED the time is 7 am – 9 pm and in FSS 7 am – 10 pm. The purpose of seasonal tariff is to guide customers to reduce their consumption during winter days when the network is most loaded and the most expensive forms of electricity generation are used.

2.3.4 Fortum Power Distribution tariff

Fortum Power Distribution is meant for large-scale electricity consumers. The Power Distribution tariff consists of basic charge, power charge, reactive power charge and distribution charge. The measuring and charging of reactive power is compulsory for Power Distribution customers. The distribution charge is higher during 1.11.–31.3. at 7 am – 10 pm. It is possible to have either low-voltage power distribution (0,4 kV) or medium-voltage power distribution (20 kV). Customers who have medium-voltage distribution have to own and operate their transformer by themselves and be responsible for its installations.

The measuring period of power charge is one hour. In FED, the power charge invoiced is the highest hourly demand of the month. In FSS, the power charge is determined by the average of the two highest monthly peak powers measured during the last five winter months. As winter months are considered November – March. The basis of power charge invoiced is at least 60 kW in FSS low-voltage power distribution and at least 200 kW in medium-voltage power distribution. The free proportion of reactive power is 20 % of the invoiced peak active power. There is one low-voltage power distribution tariff available for the customers of FED and two tariffs for the customers of FSS. Similarly, there is one tariff for medium-voltage connection to the customers of FED and two for the customers of FSS. The official tariffs are in *appendix 2* and *appendix 3* in Finnish. The distribution charge is cheaper for the customers connected to medium-voltage network, because the expenses of low-voltage network and distribution transformers are not allocated to those.

3 DEMAND RESPONSE

The traditional way to manage power supply has been to supply all demands whenever they occur, but nowadays the ideal way of operating the power system is to keep the power fluctuation as small as possible. The power balance is not easy to achieve, since the load level can fluctuate rapidly and there can be unexpected outages in the network. The power system has to keep the demand-supply perfectly in balance in real time. Demand response (DR) is one affordable solution to control the power balance in the network. Demand response means that electricity demand responses to high wholesale electricity prices or to requested power fluctuations. Moreover, demand response helps to handle emergency situations and prevent blackouts. The primary motivation of DR is to avoid peak prices and to even out consumption variation. Demand response can be achieved through reducing demand by load shedding or by shifting consumption to a less expensive period. (Abaravicius 2007) DR can be divided into incentive-based and price-based types.

Fingrid Oyj is in charge of the maintenance of frequency in Finland. The nominal value of frequency is 50 Hz. If the electricity production is greater than consumption, the frequency is above the nominal value, and vice versa, the network frequency is below the nominal value when consumption is greater than production. The balance between production and consumption is kept by frequency-controlled reserves and by manual regulations carried out in the balancing power market. Table 3.1 describes the different reserves in Finland at present. (Fingrid Oyj 2011) The fifth Finnish nuclear power plant, Olkiluoto 3, is expected to start energy production at the end of 2013. The need for fast disturbance reserve will increase, because more big power plants (Olkiluoto 3 among others) are going to be connected to the grid in the near future. Fingrid has started to build a 300 MW reserve power plant in Forssa, which will cover a significant amount of needed extra disturbance reserve.

Table 3.1. *The disturbance reserves in Finland in 2011 (Fingrid Oyj 2011).*

Reserve	Available capacity	Need
Frequency controlled normal operation reserve (50,1-49,9 Hz)	- Annually contracted, power plants 71 MW - Hourly market, power plants 50 MW - Vyborg DC-link 100 MW - Estonia DC-link 50 MW	139 MW
Frequency controlled disturbance reserve (49,9-49,5 Hz)	- Annually contracted, power plants 244 MW - Hourly market, power plants 298 MW - Disconnectable loads 40 MW	220-240 MW
Fast disturbance reserve (manually activated)	- Fingrid's own gas turbines 615 MW - Contracted capacity, gas turbines 203 MW - Disconnectable loads 425 MW	880 MW

Incentive-based (network-based) DR means an aggregator-initiated action, in which a load control occurs on a non-voluntary basis, although the customer may override the reduction signal. (Belonogova et al. 2010) The aggregator is a service provider, which manages the energy consumption of a set of clients. The aggregator collects loads of small and medium-size customers and then offers the load capacity to be sold on the market as a part of demand response. Aggregators currently only exist on a large scale in the USA. So that the aggregator business model would be possible in Finland's electricity markets, traditional electricity infrastructure requires technological change and tariff models need reforming. Two main types of aggregators can be defined:

- Load aggregators
- Generation aggregators

Load aggregators collect controllable loads, such as air-conditioning and space heating, from different types of customers and offer the aggregated loads to different market players. Generation aggregators collect and utilize dispersed generators and offer that to the market. The more common name for generation aggregators is Virtual Power Plant (VPP). A combination of these two aggregators is also possible to exist. Figure 3.1 shows how the aggregator business is managed.

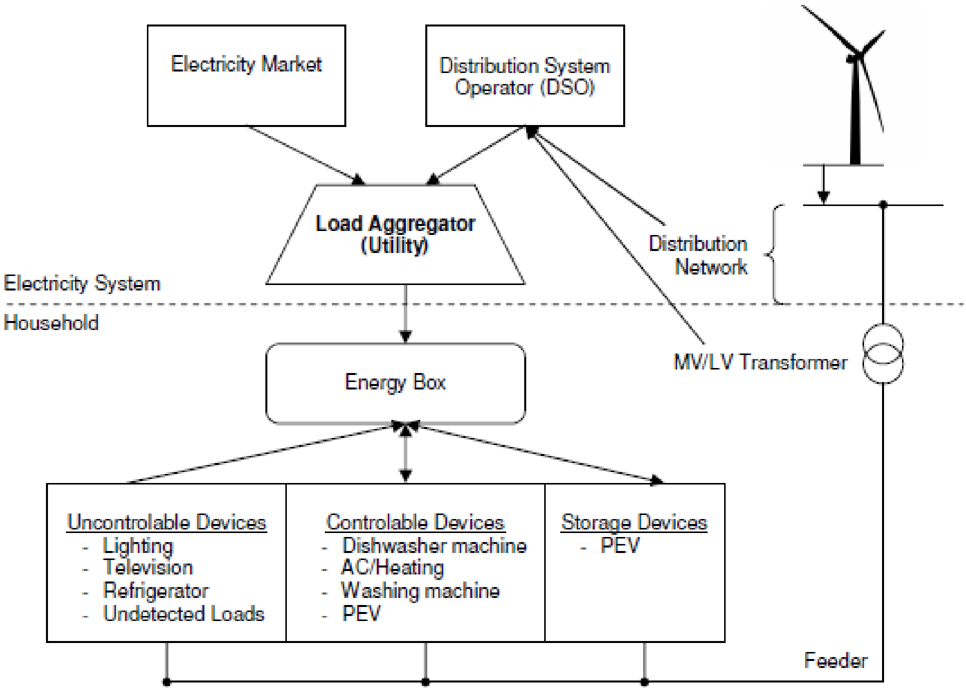

Figure 3.1. *Sketch of a Smart Grid System representing flow of information and electricity (de Sisternes 2010).*

Price-based (market-based) demand response is voluntary and the customers themselves take the responsibility of their load control. The signal for changing electricity consumption is the market price and the customers will get the information of hourly prices on the previous day. Possible retail pricing models for price-based demand response are real time pricing (RTP), time-of-use (TOU) and critical peak pricing (CPP). The simplified classification of demand response programs and how the remuneration could happen is shown in figure 3.2.

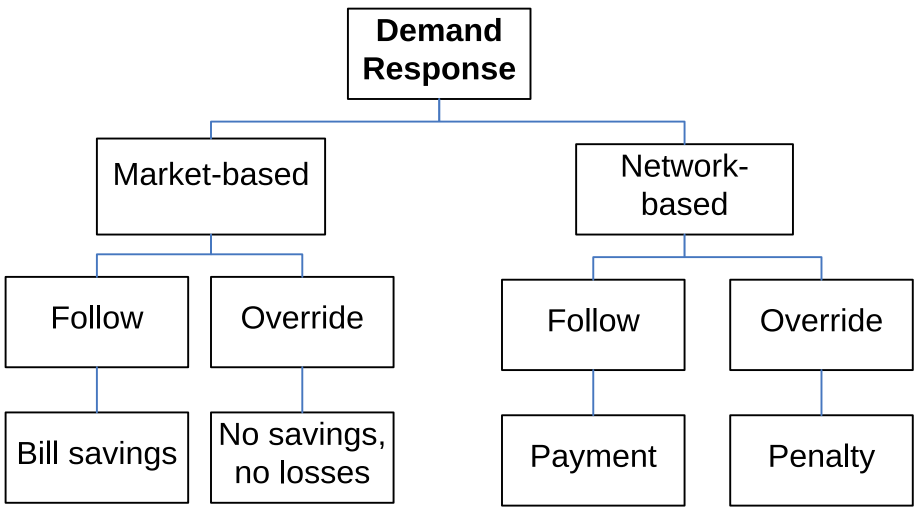

Figure 3.2. *Remuneration scheme of demand response (Belonogova et al. 2010).*

According to Abaravicius (2007) there are three types of demand response automation: manual, semi-automated and fully-automated demand response. Manual DR requires customers to manually switch off equipment. In semi-automated DR the building's energy management control system does the load shedding, in which a pre-programmed load shedding strategy is initiated by facilities staff. Fully automated DR means that the pre-programmed load shedding strategy is automatically controlled. Demand response requires peak prices to be profitable to implement. On the other hand, the increasing DR diminishes price fluctuation.

Most of the studies concerning demand response are written from retailer's point of view and the objective has mainly been to increase price elasticity in demand. Price elasticity is a part of demand response, meaning that consumption responds to the price of electricity. Whereas AMR makes possible that dynamic pricing is also implemented in distribution network tariffs. Dynamic pricing means both real-time pricing that changes every hour and critical peak pricing that allows for the retailer or DSO to occasionally declare an unusually high price for a limited number of hours. Dynamic pricing gives better opportunities for demand response and for peak shaving measures taken by consumers. Automatic meter readers are an essential part of Smart Grids. AMRs should be capable of measuring hourly energy consumption so that the elasticity of demand would be as high as possible.

3.1 Load reduction strategies

3.1.1 DR versus energy efficiency and energy saving

Energy efficiency, energy saving and demand response are all aiming at reducing energy consumption. Energy efficiency and energy saving reduce consumption more evenly than DR. Roughly saying, when discussed about energy saving the unit is MWh and when discussed about demand response the unit is MW. Abaravicius (2007) describes the difference between energy efficiency and the three demand response strategies as follows, "Energy efficiency is lower energy use to provide the same level of service. Demand limiting refers to shedding loads when pre-determined peak demand limits are about to exceed. Loads are restored when the demand is sufficiently reduced. This is typically done to flatten the load shape when the pre-determined peak is the monthly peak demand. Demand shifting is shifting the loads from peak times to off-peak periods. Demand shedding is dynamic temporary reduction of peak load when dispatched." The load shapes of three different demand response strategies are described in figure 3.3.

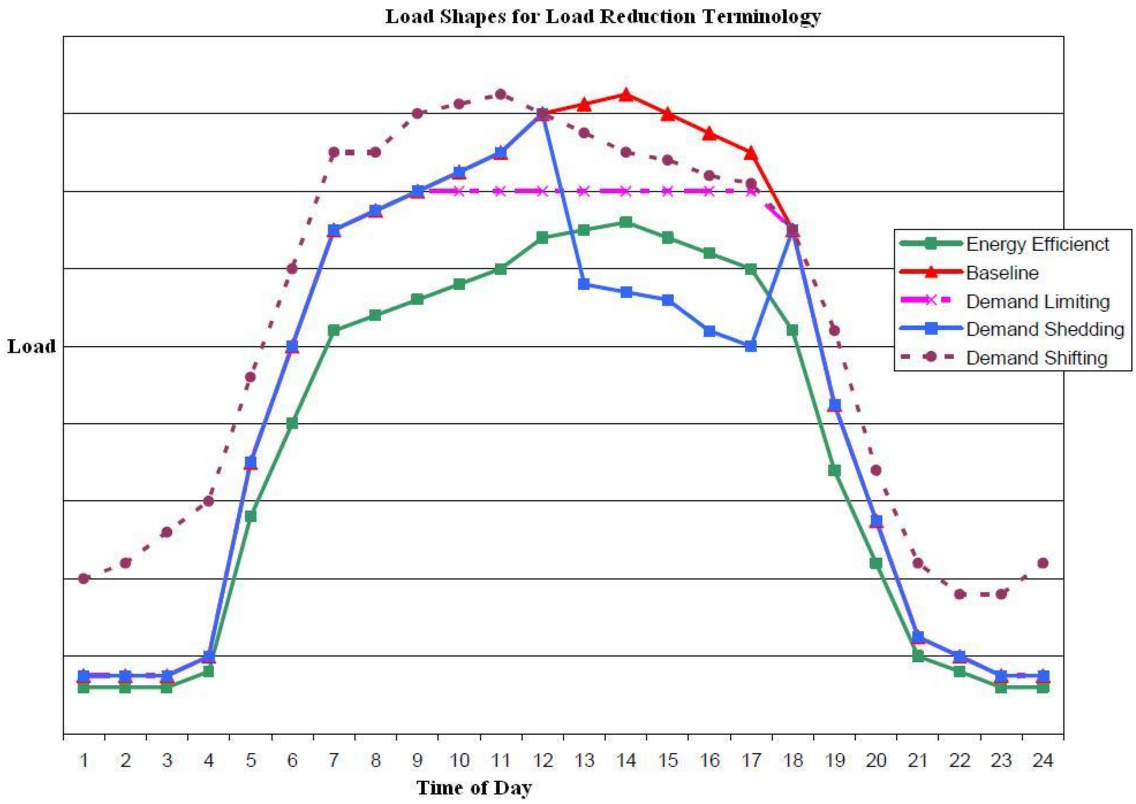

Figure 3.3. *Different load shapes that are results of different load reduction strategies (Kiliccotte & Piette 2005).*

As can be seen from figure 3.3 the energy efficiency program decreases the overall consumption evenly, demand limiting decreases consumption during peak hours evenly, demand shedding reduces consumption notably during crucial hours and demand shifting shifts consumption from significant hours to less significant hours.

3.1.2 Load management

The target of load management (LM) is to reduce or shift demand from on-peak to off-peak times. The strategies and methods of load management and demand response are very similar, but the time scale is different. LM responds to events on daily, weekly, seasonal or annual scale, whereas DR responds to hourly events in the system. (Abaravicius 2007) On the other hand, not all loads can be shifted to later time. Shiftable loads can be consumed any time and the total energy consumption is not dependent on the time when it is consumed. Shiftable loads make possible to reduce peak load periods. Examples of shiftable loads are water heating, space heating and cooling. Curtailable loads can only be used at certain time. For example, lighting cannot be shifted to another period without sacrificing user's comfort. Theoretically almost all electricity consumption is flexible if the price is enough high. Therefore, the potential for demand response is theoretically huge. (Jussila 2010)

3.1.3 Demand side management

Demand side management (DSM) comprises demand response, load management, energy efficiency and energy saving. In other words, demand side management is a common concept for electricity demand-supply balance management. Another definition of DSM is the actions of distribution system operator, retailer or government, which aim at influencing to the electricity consumption of consumers. One classification of DSM is depicted in figure 3.4. Energy efficiency and energy saving is considered as similar concept in the graph. Demand side management is becoming more and more important in distribution business. Implementation of Smart Grids causes increasing need for demand side management. Distributed generation requires remarkably more controllable loads than large-scale-based generation, since the output of most of the renewable generation techniques varies with weather conditions. Balancing electricity demand and supply will be challenging in a distributed supply system, which contains a great number of renewable generation, such as CHP (Combined Heat and Power) and intermittent generation (wind and solar power). It is likely that demand is going to be required to take more significant role in matching electricity generation. (Strbac 2008)

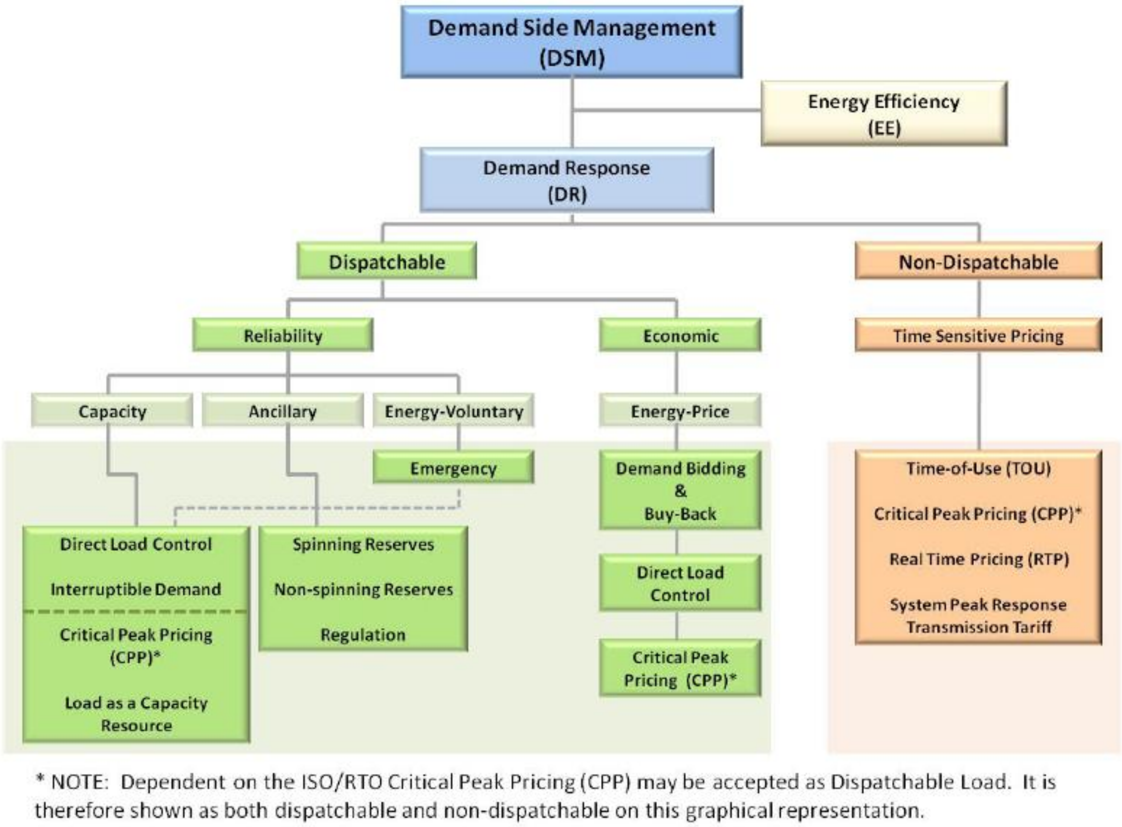

Figure 3.4. *The classification of DSM and DR programs. (Bartholomew et al. 2009).*

3.2 Benefits and possibilities of load management and demand response

DR and LM can provide many technical, economic, environmental and social benefits, even though customers' comfort may suffer from DR and LM in some scale. DR and LM help to benefit following issues (Kiliccotte & Piette 2005; Abaravicius 2007; Albadi & El-Saadany 2008):

- *Economic efficiency*: The change of electricity usage behavior and reducing or shifting on-peak usage and costs to off-peak periods results in more efficient use of the electric system.

- *Market performance and risk management:* Price volatility mitigation in the spot market is an important market improvement. DR reduces the risk of suppliers and customers in the market. One reason is that the DR reduces the ability of main market players to exercise power in the market. Even a small reduction in demand can lead to a remarkable price reduction. It is so because the cost of power generation increases remarkably near the maximum generation capacity. For example, it has been estimated that 5 % decrease in demand could have caused a 50 % reduction in wholesale price spikes in California during the electricity crisis in 2000 – 2001.

- *Reliability of the system:* Operators will have more options and resources to maintain the system reliability during emergency conditions, therefore the amount of forced outages reduce.

- *Reduction of costs:* Demand response is an economical resource to operate systems, since the electricity system infrastructure is highly capital intensive. Decrease in the investment level will cause remarkable savings.

- *Consumer service:* DR gives more choices for consumers, e.g. they can manage their consumption with market-based programs and dynamic pricing programs.

- *Environmental impact:* If the infrastructure investment level is reduced, there are a number of benefits for the environment. Need for land utilization will diminish because of avoided or deferred generation unit and transmission/distribution line investments. Air quality will improve because of efficient use of resources. For example, carbon dioxide emissions will reduce if, for instance, gas turbine power plant usage can be avoided when there is no need for peak power generation. As can be seen in figure 3.5, the most polluting electricity generation techniques are generally used during the highest demand. The greenhouse gas emissions in carbon dioxide equivalents of different electricity production methods are shown in figure 3.5. Even a small reduction in power consumption will effect positively on climate pollution. In Finland, the electricity production technologies that are being used mainly only during the highest power need are coal condensing power, oil condensing power and gas turbines. For example, the emissions of coil condensing power are 800 – 1000 g/kWh.

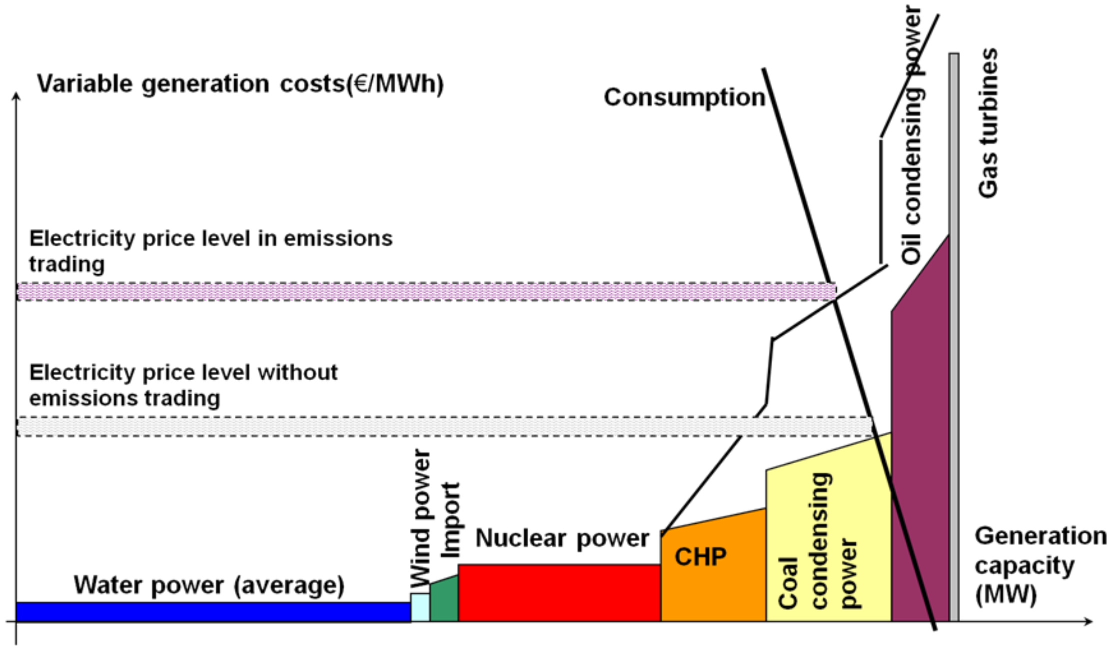

Figure 3.5. *The wholesale price of electricity and the effect of CO2 emissions trading on price formation. Adjusted from (Partanen et al. 2010).*

Figure 3.6 shows the emissions of different power plants. Power plants were surveyed from several parts of the world. In the figure 3.6, low means the lowest researched emissions and high means the highest emissions of the power source. In addition, FGD means flue gas desulphurization, CC means combined cycle, SCR stands for selective catalytic reduction and IGCC means integrated gasification combined cycle.

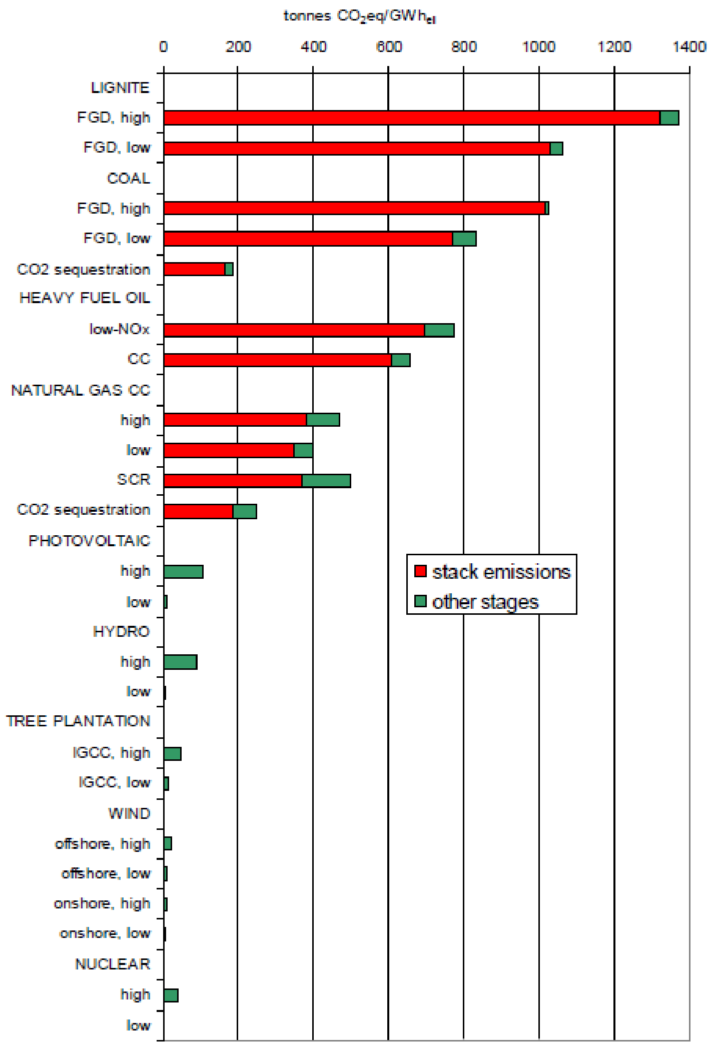

Figure 3.6. *The greenhouse gas emissions of fossil, renewable and nuclear energy systems (WEC 2004).*

3.3 Impact of demand response on energy efficiency and energy saving

Energy efficiency means using less energy to provide the same or improved level of service to the consumer in an economically efficient way, in other words, energy efficiency does not reduce comfort. Energy saving is considered as reduction in energy use by, for example, lowering thermostats during the heating season and switching off unnecessary lightning. Energy saving is often occurred through behavioral changes that are short-term, whereas energy efficiency actions are done by installing long-lasting technologies. Furthermore, the target of demand response programs is to curtail or shift loads for short periods.

Fortum Sähkönsiirto Oy and Fortum Espoo Distribution Oy have committed to a voluntary energy efficiency skeletal agreement, which was agreed between Ministry of Trade and Industry, branch unions and Confederation of Finnish Industries on 4 December 2007. DSO's are required to follow the energy saving target, which aims at reducing network losses. FSS and FED have committed to make their own energy usage more effective. The target is to reduce 5 % of network losses during 2008 – 2016 compared to the level of 2005. The companies that are committed to the agreement have to frame a plan for energy efficiency efforts and they shall update it as the need arises. The incentive for this agreement is Directive 2006/32/EC, which determines that EU Member States are required to save 9 % of the final energy consumption by 2017 compared to the level of 2005. Demand response is one method to achieve these energy efficiency targets.

Smart grids and especially intermittent generation might cause need for negative price signals. If in micro grids, and in areas where exist transmission bottlenecks, happen overproduction of renewable energy, demand side should respond to it by consuming more electricity. Customers that participate in demand response programs should get some monetary discount in those times when electricity is produced too much, in case that there are bottlenecks at that time. Since electricity cannot be stored in reasonable way for many years, demand side should participate more to sustain system security. Not only energy saving is useful for the grid, sometimes extra consumption is required to maintain the balance between production and consumption.

When customers get proper energy use feedback and participate in demand response programs with TOU and dynamic pricing it is likely that customer's total energy use and cost also reduce. Coordination of DR and energy efficiency would be very beneficial, because it could increase cost efficiency and increase more rational allocation of resources for both program providers and customers. Coordination of DR and energy efficiency would help customers, since most customers might not understand and care about the difference between energy efficiency and DR. Higher customer willingness could also increase DR market penetration and then customers could get better results from energy saving and bill-reduction opportunities that might otherwise be lost.

Coordination of energy efficiency and demand response could be done at least in following ways: combining program offerings, coordinating program marketing and education, offering market-driven coordinated services, and changing building codes and appliance standards. Nowadays the customers are normally offered separate programs, but they should be presented with both energy efficiency and DR opportunities so that contradictions were minimized. The marketing and promoting of DR and energy efficiency should be done in a closely coordinated or unified way, because these topics can be very complicated. The both topics should be unified under broad energy management theme. Moreover, fewer customers are familiar with demand response compared to energy efficiency. DR and energy efficiency require sophisticated customer effort and action, therefore program marketing should include good educational material.

The initiative for coordination does not have to arise from DSO or retailer, whereas private companies that find a market among customers, which are interested in reducing their energy costs, could start to promote it and create new business. The updating of building codes and appliance standards would also be a good way to promote energy efficiency and demand response. Energy efficiency and demand response features could be incorporated directly into building design and infrastructure and appliance designs through codes and standards. In this way, customers could get notable reductions in costs of integrating energy efficiency and DR strategies and measures.

3.4 Challenges and costs for DR and LM

Large-scale industry is already taking part of market-based demand response in notable scale in Finland (Työ- ja elinkeinoministeriö 2008). Whereas the household customers have a limited possibility to take part of demand response in Finland. Most Finnish DSOs provide night tariff possibility for their customers. Nighttime tariff was introduced as early as 1960s in Finland, so Finnish utilities have been real forerunners of demand response.

Obstacles to DR are, for instance, the inelasticity of demand and low level of participation due to lack of knowledge. The potential of DR varies between different European countries, since the household consumption profiles vary significantly. AMR roll-out timetable and potential of manageable industrial loads are also different. (Torriti et al. 2010) Either there is no clarity for aggregator business concept or it is still undetermined who is going to take response of it.

Both parties, customers and DSOs, will face expenses. The costs are divided into initial and running costs. Initial costs for customers are for example costs of installing enabling technologies and the establishment of a response strategy. Running costs for the customers are inconvenience, lost business, rescheduling and backup onsite generation. Inconvenience may occur for instance when customers will have to switch off heating or air-conditioning for a while. Initial costs for program owners include installation of metering and communication appliances and systems, as well as customer education and upgrading of the billing system. The outcome of demand response is highly dependent on customer education, since the customers need to choose the best DR program for themselves and understand the benefit of it. Running costs of demand response are administrative, marketing and incentive payments. (Albadi & El-Saadany 2008)

3.4.1 Conflict between DSO and retailer

One major problem is the conflict between distribution system operator and retailer, because both may have different perspectives on load control. They both have the same object, to maximize their business profit, but their way to reach it is different. The retailer is interested in minimizing energy acquisition costs, whereas DSO's interest is to keep the consumption profile as even as possible by avoiding demand peaks. Thereby DSO will accumulate savings by avoiding long-term investment expenses and savings from loss reduction.

A retailer maximizes their profit by selling energy with as high price as possible and buying with as low price as possible (Belonogova et al. 2011):

$$max \int_0^T profit(t)dt = max \int_0^T (E_{sell}(t) - E_{buy}(t))dt \tag{6}$$

The retailer's target is to purchase energy from Nord Pool Spot at low prices as much as possible and at high prices as little as possible. The spot prices in the Power Exchange do not necessarily follow the state of the local distribution network. DSO aims at minimizing investment, operational costs, loss and maintenance costs in long-term:

$$C_{tot} = min \int_0^T \left(C_{invest}(t) + C_{loss}(t) + C_{outage}(t) + C_{maintenance}(t)\right) dt \tag{7}$$

Consistent load control can reduce peak power of the network in long-term, but it may also increase it if retailer takes all load control power at his own disposal. There is a peak every evening at 10 pm caused by electric heating loads. At the system level, most of the public, commercial and industrial customers have already stopped working by that time; therefore, the spot price does not follow this rise in consumption, which is only caused by residential customers. This is illustrated in figure 3.7. Real time pricing does not smooth the feeder's second evening peak since the price curve often counteracts the power profile after nine or 10 pm. Hence, direct load control activities in addition to real-time pricing are required to smooth the peak power caused by electric heating loads.

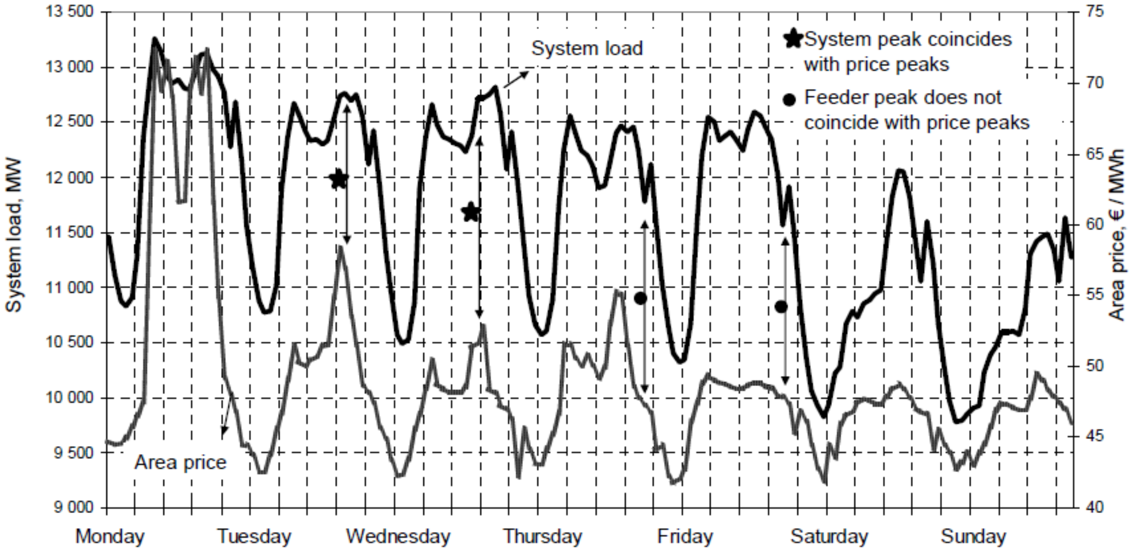

Figure 3.7. *Hourly spot prices and powers during a week (Belonogova et al. 2010).*

In (Belonogova et al. 2011) three different scenarios have been analyzed in which compromises were realized between the retailer and DSO by tariff design. Three different tariff models were designed for a family living in a detached house with direct electric heating load:

1. Energy-based component is variable, power-based component is fixed.
2. Power-based component is variable, energy-based component is fixed.
3. Both energy- and power-based components are variable when the power limit is exceeded.

The results were case specific and depending on the input data. A research finding of the paper was that the dynamic network tariff has to satisfy both the interest of customers and DSO. Increasing of energy-based component exposes DSO to the risk of high investment costs and increasing power-based component exposes customer to the risk of high electricity bill. Furthermore, it is difficult to invent an attractive dynamic tariff with both spot price-based and dynamic network tariff, since customer's comfort should not be strongly disturbed and at the same time, it should bring financial benefits to them.

Spot price does not give the best possibilities for domestic consumers to shift their loads, because the prices vary every day, so it requires fully automatic system that demand response could result. It might decrease customer participation if they have to purchase some expensive load control devices or automation systems. Spot-pricing includes a risk for the customer, because the retailers want to transfer the risk from themselves to the customers. Whereas the new network tariffs that are presented in this thesis contain only a small risk for the customer, because the tariffs are designed so that the yearly payment will be about the same if they do not change their consumption, but it will be smaller in case they change their consumption to the more affordable hours. In figure 3.8 is shown the Elspot prices of 2009.

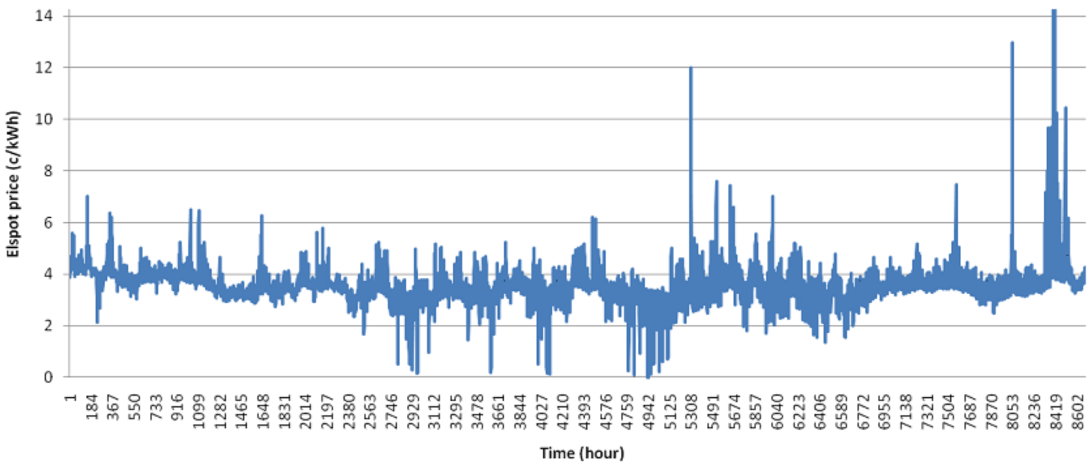

Figure 3.8. *Elspot price in Finland in 2009, the highest peak (around 140 c/kWh) is cropped from the figure (Nord Pool Spot 2011).*

3.5 Preconditions for DR

The most important precondition for DR is AMR system that collects hourly consumption data. The data should be possible to be transferred in two-ways. So that DR would be practicable, control signal needs to be transmitted from DSO to customer. The updates of meters also need two-way data transmission. Demand response requires as well that the meters are capable of load control, in other words, the meters have to contain a relay for load control in Finland. (Työ- ja elinkeinoministeriö 2008).

Demand response has high requirements for data transmission system. Measurement data and load control signal has to be transferred quickly enough and reliably. Not all DSO's know what the data transmission capacity in the existent networks is, and that information is important to find out. Minimum requirements for control signal's transit time should be set. Although meter reading works in the network, there can be problems in two-way data transfer between software and devices produced by different manufacturers. In the worst case, the transit time of load control signal can be several hours, so the delay is too long in power shortage situation. If the load management potential is wanted to be raised, the capability of building's control system has to be enough high. (Työ- ja elinkeinoministeriö 2008).

Legislation of Finland requires that the hourly interval metering equipment of delivery site have to be read at least once in a day. Customers have a right to get access to their consumption data without any extra payment. Hourly metering data must be accessible for the DSO and consumer simultaneously. Without customer's permission, DSO can only give the consumption data to retailer. (Työ- ja elinkeinoministeriö 2009)

When consumption data is transmitted between different parties, such as DSO and aggregator, and saved in different locations it is very important that data privacy will be taken into consideration. The consumption data of individual customers has to be protected from external parties so that data abuse is prevented. Some customers might be afraid of data security, because they do not want that criminals could get access to their consumption data.

3.5.1 Drivers of demand response adoption

A part of EU's Europe 2020 strategy concerns climate and energy. The member states are committed to reduce greenhouse gas emissions by 20 %, increase the share of renewable energy sources of EU's energy mix to 20 %, and to achieve the 20 % energy efficiency target by 2020. The former targets are on their way to be achieved, but the latter needs further actions. The EU published a Roadmap for moving to a competitive low carbon economy in 2050. The objective of Member States is to reduce greenhouse gas emissions by 80 – 95 % by 2050 compared to the level of 1990. (European Commission 2011)

The increasing amount of renewable energy sources will cause challenges to electrical networks, because the power generation does not always follow the consumption. For example, the wind power generation is very variable because of wind speed fluctuations. Wind power requires control power so that the generation would be equal to consumption. Demand response can bring reductions to generation capacity investments and therefore reductions to the amount of greenhouse gas emissions. DR is a very climate friendly alternative to power control and the EU's climate policy supports it. DSO's will have to identify cost-effective solutions to integrate decentralized generation into the market without sacrificing system reliability. (Smith, Hledik 2011)

Smart meters will make the demand response adoption possible. On the other hand, demand response will bring additional value to the meter owners, because the technology will be used more effectively. Smart meters enable innovative tariff designs and technologies that will produce demand that is more responsive.

Electric vehicles

In future, the electric vehicles (EV) would increase the system power without well-designed tariff models. For example, the peak power might exist when people return from work in the evening. Well-designed tariffs encourage charging during the off-peak hours. Electric vehicles could also be part of directly controllable loads in future.

In case study conducted by Peltonen et al. (2010) was found that, the need for intelligent control of charging of EV's increases exponentially as EV penetration level passes 25 %. When the penetration level stays under 25 % there is no remarkable significance for intelligent charging. The worst starting time for EV charging is at the same time as storing hot-water tanks are switched on. It is better not to control the charging than to start the charging with storing hot-water tanks. The intelligent control of charging of EVs will result in avoided unnecessary reinforcement investments and the need for distribution tariff increase becomes less. If the charging of EVs is not controlled intelligently, the load growth can vary from 20 % to 50 % in the case study feeders. In some inspected feeders the optimal time for charging would be in the day time. It would not be possible without energy storages, because the cars are not there then. (Peltonen et al. 2010) The batteries of electric vehicles can be used as energy storages if there is a need for flatten out power peaks. A hindrance is that people might not want that electricity could be discharged from their car's batteries without proper reimbursement. The power level of discharging is also unsure. Fault current protection also has to be updated if batteries are discharged to the network. The discharging of batteries would be very useful in micro grids, because output power of renewable energy sources is volatile.

3.6 Demand response programs

The following programs are in use or pilots in USA. The potential of different program category for each U.S. state is presented in *appendix 4*. (U.S. Department of Energy 2006)

Price-based DR tariff options

- *Time-of-use (TOU):* is a rate with different unit prices for usage during different blocks of time, usually defined for a 24-hour day. TOU rates reflect the average cost of generating and delivering power during those time periods. The rates often vary by time of day and by season. TOU tariffs require meters that register cumulative usage during the different time blocks. In Finland, a typical TOU tariff is nighttime and seasonal tariff.
- *Real-time pricing (RTP):* The price of electricity fluctuates hourly reflecting changes in the wholesale price. RTP prices are typically known to customers on a day-ahead or hour-ahead basis. Participants are assigned a baseline load shape.

If the customer uses more energy in an hour than their baseline for that hour, the customer will be charged for energy at that hour's market price. The converse is also applied, the customer will get credit for energy, which is not used. Other market based rates may also be applied.

- *Critical peak pricing (CPP):* CPP rates include a pre-specific high rate for usage designated by the utility to be a critical peak period. CPP rates may be superimposed on either a TOU or time-invariant rate and are called on relatively short notice for a limited number of days and/or hours per year.

Incentive-based programs

- *Direct load control:* Utility or system operator remotely shuts or cycles a customer's electrical equipment on short notice to address system or local reliability contingencies. Customers often receive a reimbursement from participation, usually in the form of an electricity bill credit. A few programs provide customers an option to override or opt-out of the control action. On the other hand, overriding the control reduce customer's incentive payments. Direct load control programs are primarily offered to residential and small commercial customers in USA.
- *Interruptible/curtailable:* Customers will get a rate discount or bill credit for agreeing to reduce load during system contingencies. Customers who do not reduce their load will pay very high electricity prices that come into effect during contingency events, may be removed from the program.
- *Demand bidding/buyback program:* programs that either (1) encourage large customers to bid into a wholesale electricity market and encourage to offer to provide load reductions at a price at which they are willing to be curtailed, or (2) encourage customers to identify how much load they are willing to curtail at the price determined by the utility. Customers whose load reduction offers are accepted, must either reduce load as contracted or face a penalty. Customers may have the option of obtaining enabling devices, such as smart switches or thermostats or in-home displays, to help them save during critical events.
- *Emergency demand response programs:* customers are offered incentive payments for measured load reductions during reliability-triggered events. If customer does not respond to load reduction demand, they may or may not face penalties.
- *Capacity Market Programs:* Customers provide pre-specified load reductions when system contingencies arise. Customers typically receive day-of notice of events. Customers that do not respond when called typically receive significant penalties.
- *Ancillary Services Market Programs:* Customers bid load curtailments in ISO/RTO markets (Independent System Operators/Regional Transmission Organization) as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby.

The peak reduction potential per different program type and the number of demand response programs in the USA is shown in figure 3.9. One major difference between U.S. electricity market and the Nordic electricity market is that nodal pricing is in use in transmission network in the USA and zonal pricing in the Nordic countries. The nodal pricing model is in practice in the USA, because there is scarcity of transmission capacity. In the nodal pricing, TSO is responsible for the operation of transmission grid and the electricity price calculation. (Wight et al. 2011)

	During Calendar Year 2010		During Calendar Years 2011 and 2012		During Calendar Years 2013 through 2015	
Program Type	Number of Programs	Potential Peak Reduction (MW)	Number of Programs	Potential Peak Reduction (MW)	Number of Programs	Potential Peak Reduction (MW)
Direct Load Control	253	3497	324	4980	563	6301
Interruptible Load	122	7557	119	7771	121	8328
Critical Peak Pricing with Controls	13	234	19	395	22	813
Load as Capacity Resource	36	1393	22	1386	22	915
Spinning Reserves	10	1639	11	1419	10	1390
Non-Spinning Reserves	5	316	8	92	11	232
Emergency Demand Response	53	2027	46	1968	33	3196
Regulation Service	3	105	5	85	6	155
Demand Bidding and Buyback	4	240	6	227	5	425
Time-of-Use Pricing	219	1283	205	1388	193	1489
Critical Peak Pricing	42	354	62	624	66	910
Real-Time Pricing	24	1259	30	1269	29	1271
Peak Time Rebate	13	9	27	643	27	1165
System Peak Response Transmission Tariff	3	36	4	111	3	311
Other	35	2444	27	2436	25	2722

Figure 3.9. *The plans for different demand response programs in the USA. (Wight et al. 2011).*

The timescale how different DR programs are incorporated into system planning varies is demonstrated in figure 3.10. TOU programs and capacity services are planned months before delivery. RTP and demand bidding is scheduled one day ahead. CPP, emergency programs, interruptible programs and direct load control are called on during the same day as load reduction delivery.

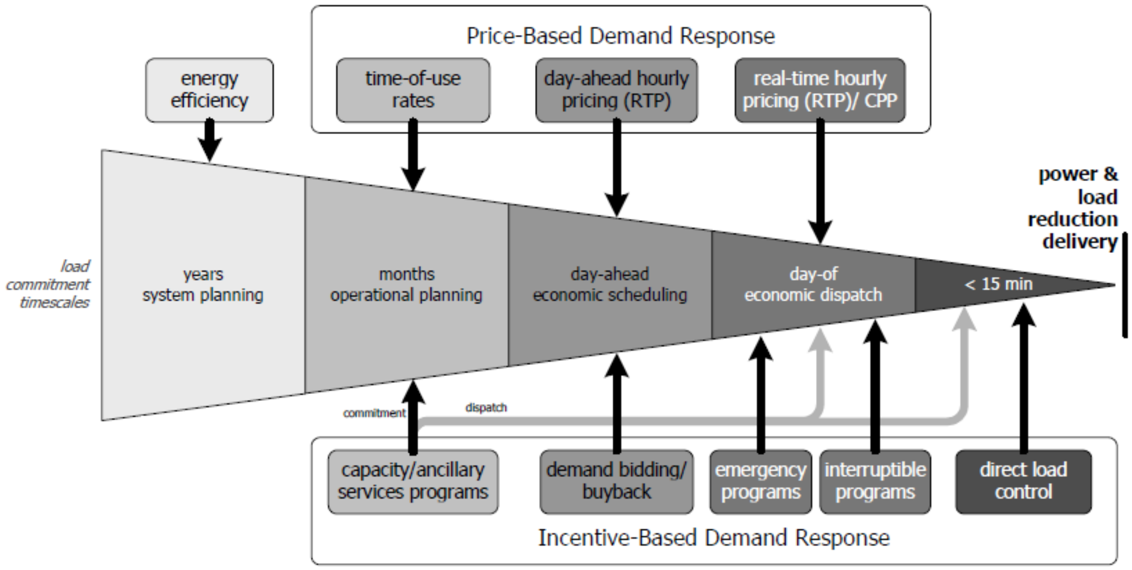

Figure 3.10. *Role of demand response in electric system planning and operations (U.S. Department of Energy 2006).*

Types of Customer Load Response

Customers who participate in demand response options may respond to high prices or program events in three ways (U.S. Department of Energy 2006):

- *Foregoing:* Customers reduce energy usage at times of high prices or demand response program events without making it up later. In both cases, loss of comfort results.
- *Shifting:* Customers reschedule usage away from times of high prices or demand response program events to other times. The lost amenity or service is made up either prior to or at a subsequent time.
- *Onsite generation:* some customers may respond by turning on an onsite or backup emergency generation to supply some or all of their electricity needs.

4 AUTOMATIC METER MANAGEMENT AND CONSUMPTION PROFILES

4.1 Automatic Meter Management

Finnish legislation requires that all the consumption points with maximum 3x63 A main fuse have to have hourly metering equipment and the DSO's information system has to fulfill the operational requirements of law by December 31, 2013. The consumption points with over 3x63 Ampere main fuses and small scale production units had to be in hourly meter reading by December 31, 2010. The rollout of AMR meters to Fortum's customer's maximum 3x63 A main fuse consumption points started in April 2011. The minimum operational requirements for AMR equipment and meter infrastructure are following (Työ- ja elinkeinoministeriö 2009):

1. The hourly metering device has to be read at least once a day
2. The data registered by measurement device has to be capable to be read from memory via communication network
3. The metering equipment has to register the starting and ending time of the over three minute power cuts
4. The metering equipment shall be capable of receive and implement the load control commands coming from communication network
5. The metered data and data concerning de-energized time period shall be saved to DSO's information system, where the hourly metered data shall be stored at least six years and the information concerning de-energized period at least two years
6. The metering equipment's and DSO's information system's data privacy shall be secured appropriately
7. DSO has to provide hourly metering equipment with standardized interface for real-time electricity consumption monitoring if the customer orders it separately.

Advanced metering infrastructure brings many improvements and reform to network operations. AMI enables two-way real time data transfer. The devices and data transfer are coded comprehensively. AMI brings several benefits, such as possibility to dynamic pricing, hourly consumption data, sales receivables turnover shortens, information about quality of electricity, real time monitoring and demand response features. AMI also supports energy saving, remote programming and detects power outages and offers possibility to new functions. Figure 4.1 shows the upper level description of AMM functions and systems.

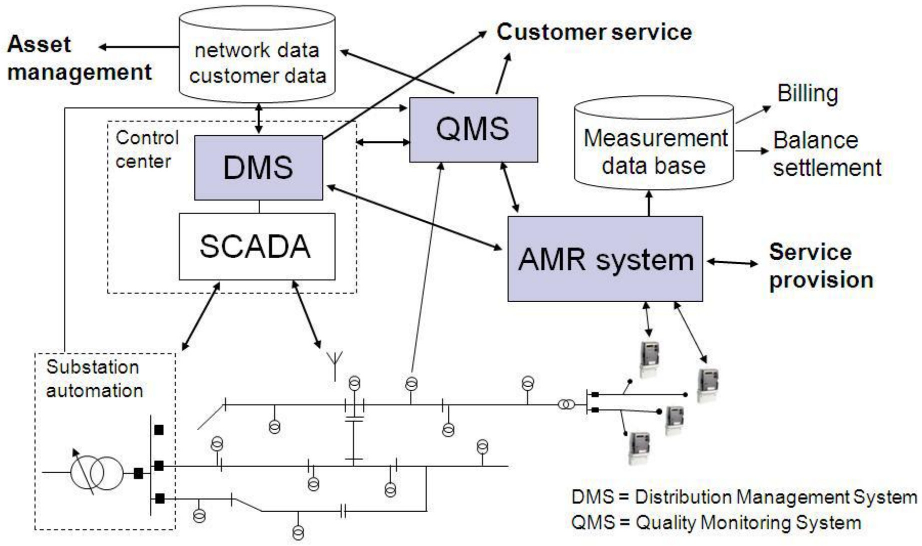

Figure 4.1. *AMM system's linkages (Verho 2008).*

In Fortum's metering infrastructure, there are data concentrators that detect the AMR meters in the neighborhood, collects their consumption data and sends it to the utility via 3G or 2G network. Moreover, the load control commands and other data transmission are transmitted to the meters through the data concentrators. The data concentrators communicate with the meters in all three phases, take care of time synchronization and detect the line and device faults. Data concentrators use PLC (Power Line Communications) technique to communicate with meters. They also collect the invoicing data, collect the meters daily consumption and determine if some other data concentrator has a better data line to some meter. Data concentrator is an active network control unit, whereas meters are passive. The AMM system is shown in figure 4.2.

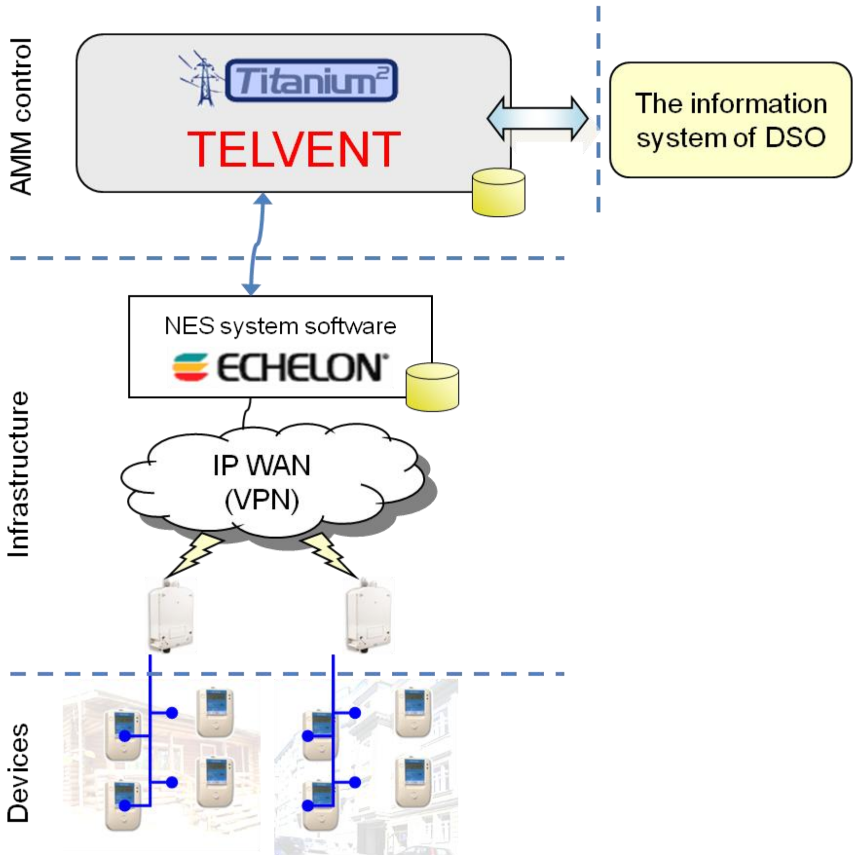

Figure 4.2. *AMM system that is used in Fortum's network in Finland (Hauta-aho 2011).*

4.1.1 Software fuse

The new AMR meters that are being installed to Fortum's consumption points have software fuse functionality. The software fuse is designed to detect the consumption which is over a reference limit. It is not designed to detect and record over-current surges. The load disconnect contactor does not have thermal overload or over-current protection. Therefore, the system needs to have external fuses or circuit breakers for protection. The power is cut off if the software fuse limit is constantly exceeded. The threshold of the maximum active power value and the time duration is utility configurable. It can be defined whether the whole power from the connection point is cut off or only the loads behind a relay. In future, software fuses can also be a tool to define the real size of connection, based on the software fuse limit.

The software fuse makes possible to provide new types of network tariffs in future. There is a reference current determined to the meter, it is the meter's maximum current by default, unless configured otherwise. The meter measures the consumption to a different tariff register if the current is exceeded percentage X over the reference current time Δt. How an event is determined is presented in figure 4.3. The meter sends an indication to Fortum when the software fuse limit is exceeded. In that case, it will also send an on/off command to a Zigbee based device, although it is possible after some product development in future.

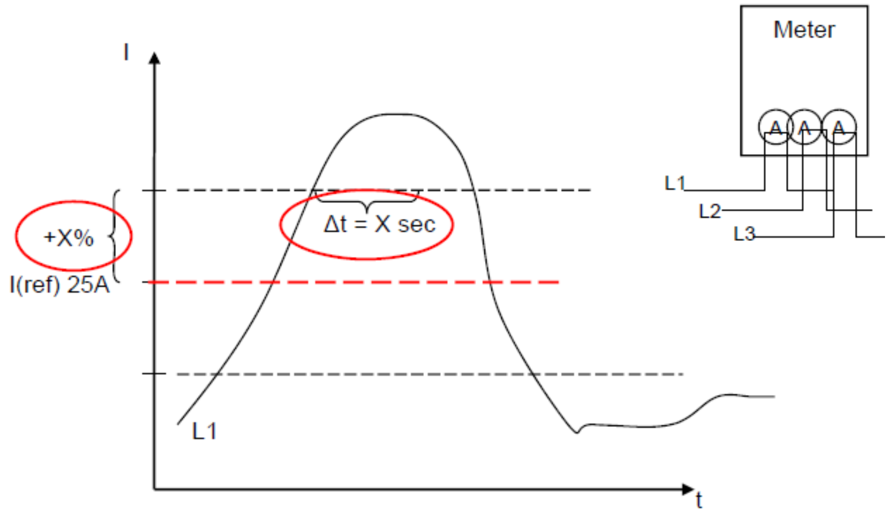

Figure 4.3. *Sketch of software fuse reference levels (Hauta-aho 2011).*

Software fuse technology enables tariffs that have more affordable rates under the reference current and more expensive when the threshold is exceeded. It is configurable, which is the trip point of load disconnection. If the load is disconnected, the customer can reset it manually. That function can be enabled or disabled. For example, software fuse could enable tariffs, which give customers a certain Ampere-based "bandwidth", which would be lower or same sized as the main fuse.

In addition, there exist also other smart devices to help participating in demand response programs. These are shown in figure 4.4. HAN in the picture means Home Area Network.

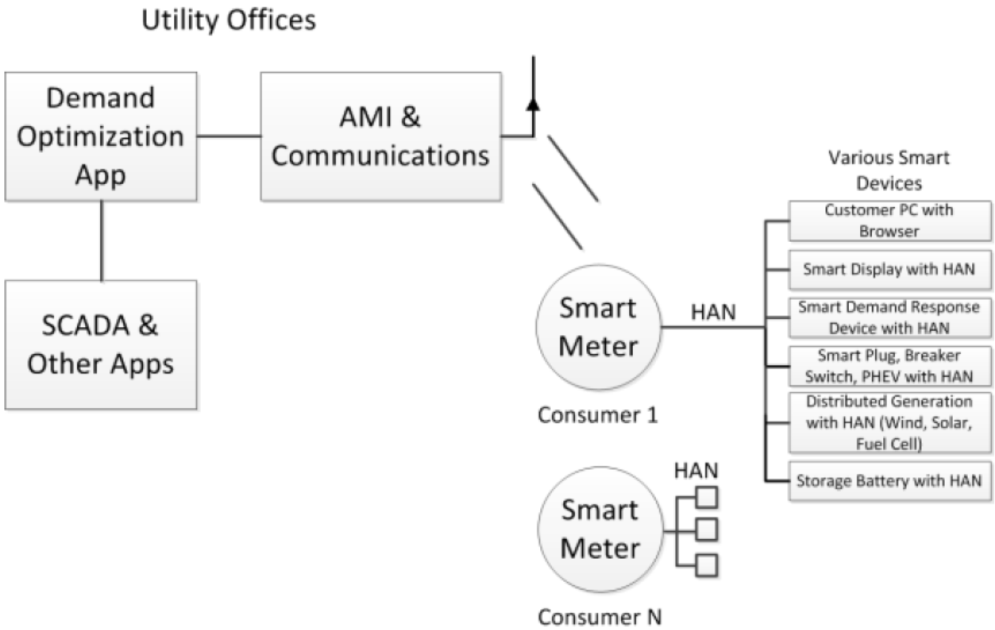

Figure 4.4. *The different devices that make demand response possible (Gulich 2010).*

4.1.2 In-home displays

In-home display is a device, which is installed inside an apartment and shows information about customer's total energy consumption visually clearly. Customers are not willing to follow their AMR meter's reading daily, because the information is not diverse and the meter is not usually easily reachable, especially if the meter is located outside of the building. That is why in-home displays are developed. The Zigbee radio signals do not carry if the meter is outside, but purpose is to offer the service in future. Nowadays the Zigbee radio signals carry 50 m in open space. In-home display technology is quite new. That is a reason why it has been tested in several pilots. Fortum had a pilot going on in Sweden and in Finland with in-home displays and the pilot projects had been a success. The Fortum in-home display was released in September 2011 and it is being marketed to household customers. The display model that is being sold in Finland is shown in figure 4.5. It has been estimated that the in-home displays would bring even 10 % annual energy saving, grounding on the fact that people would then know how much they exactly consume energy and how using of some device affects on their bill. The consumption data updates every 8 – 10 second. Currently the in-home displays enable following things for example:

- Inspection of household's instantaneous electricity consumption
- Inspection of energy consumption costs in a longer period
- Detection of individual device's energy consumption by unplugging the device
- Receiving and acceptation of messages that come from service provider
- Advice to save energy and information if the customer's or the whole country's energy usage is high
- Setting of target levels and comparison between previous week
- Inspection of consumption history data from computer

Figure 4.5. *GEO in-home display (Fortum Oyj 2011).*

Several kinds of development proposals of in-home displays for their vendors have arisen. One theme relates to changing price signals. Currently the meters are not capable of receiving hourly price information without upgrade to meters. Hourly values would need at least 25 slots in the meter to store the values.

If the customers have their own micro production, in-home displays are not capable of showing the amount of production currently. Microgrid production would require a separate metering point and meter from where it could be sent to the in-home display. Without any development, meters would only show the net consumption, so the micro production and household's consumption could not be shown separately.

After some development, customers could get information to their displays about demand response request and load control actions and then they could choose whether they want to participate or not and at what time. The response would be sent via the display. Then the DSO would get important advance information of how many are willing to participate. Moreover, if Zibgee 1.0 technology was developed, utility could be able to control some wall sockets or devices.

4.2 Consumption profiles

Consumption profiles have been created to give DSOs better estimation of their customer's load usage. Currently consumption profiles represent the time dependency of power of an average customer in a certain group. At the moment, the principle that consumption profiles represent certain consumption group is changing towards AMR based group selection in Fortum ESD's systems. AMM will make possible that consumption profiles could be created for higher interval than one hour, for example half an hour. On the other hand, the electricity markets provide only hourly products, so the benefit would be small from it. More information about currently used consumption profiles can be studied from (Jalonen et al. 2003).

More accurate consumption profiles will reduce the amount of needed balance power and the forecasting of consumption is always more precise with consumption profiles than forecasting that is based on raw historic data. If the consumption profiles are improved, it will result in narrowing the gap between the actual and estimated consumption. The benefit from more precise consumption profiles for a DSO is that in network planning, the calculation results are closer to actuality. Hence, the electricity network will be designed more properly to correspond the actual consumption level.

The design of new consumption profiles was started by creating a model for temperature dependency of load consumption. Hourly consumption data was collected from Tuusula pilot area and it contains one-year data. A great number of the houses were electrically heated detached houses. The hourly temperature readings were taken from Helsinki-Vantaa airport, where the closest meteorological station is situated. Temperatures were measured three times in an hour and they were averaged to one temperature figure of the hour. The temperature dependency model was created by using the same assumption as in current index-model. The principles of creation of temperature dependency modeling are described in (Koivuranta 2011). The new model improves load forecast. In equation (8) is described how change in temperature affects on change in power.

$$\Delta P = \Delta T * P_i * (a\, ln(T_i) + bT_i + c) \qquad (8)$$

Where
ΔP = Change in power
ΔT = Change in temperature
P_i = Customer's hourly power
a, b, c = Correction coefficients that were calculated with a program that was created for the purpose of calculating them.
T_i = Temperature of hour i (Kelvin degrees)

Generally, the peak power of several similar consumer types is calculated with equation (9). The fault in the calculation is that in this method it is assumed that the peak hour will happen during the hour when the probable power is the highest. In fact, the actual peak hour can happen in any hour of the year. It is just less likely to happen during the hours when the probable power is lower. Every hour of the year has the possibility to be the actual peak hour. Therefore, the assumption to ignore all the other hours but the hour when the probable power is the highest is incorrect. Moreover, it is not right to combine dispersion this way, because they are not dependent on each other in real life. There is an inner conflict in the calculation, because it assumes that variation factor is constant and deviation is linearly dependent on yearly consumption. When the different customers' powers in a certain group are summed together, it is assumed that their deviations are equal, which is impossible if the consumptions are different. The deviations are only slightly dependent on each other and when peak powers are calculated, it is crucial to assume that deviations are not dependent on each other.

$$P_{max} = n \times \overline{P} + z_a \times \sqrt{n} \times \sigma \tag{9}$$

Where
n is the number of customers
$\overline{P}$ is the net power of that hour
z_a is coefficient, which corresponds exceeding probability of variable a from standard deviation
σ is dispersion

The network calculation program PowerGrid does not either calculate the peak power mathematically right, so an equation (11) was formed in (Koivuranta 2011) to make the results more exact using standard deviation. Its density function is:

$$G(x) = \left(\frac{1}{\sigma(x) \times \sqrt{2\pi}} \times e^{\frac{-(A-P(x))^2}{2(\sigma(x))^2}} \right) \tag{10}$$

The peak power of a customer should be calculated from standard deviation using equation (11) (Koivuranta 2011). It is depicted in figure 4.6.

$$F(x) = \prod_{x=1}^{8760} \left(1 - \frac{1-\Phi\left(\frac{A-P(x)}{\sigma(x)}\right)}{2} \right) \tag{11}$$

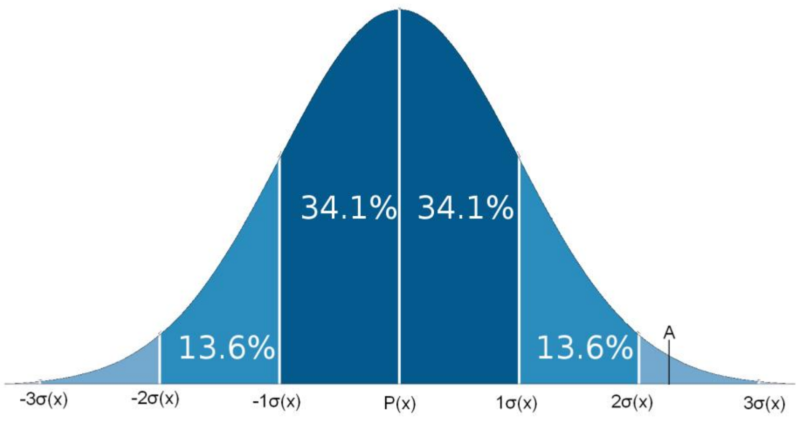

Figure 4.6. *Density function of standard deviation with limit A. Modified from (Wikipedia 2011).*

In equation (11) F(x) is the probability that a customer does not exceed the power limit A during a year. Probability that limit A is not exceeded during hour x is area from –∞ to A, it is shown in figure 4.6. When F(x) = 0,5, A is the peak power (P_{max}) of a year. It means that with 50 % probability the customer's peak power is not going to exceed limit A. In other words, it is the same as the most probable peak power value of a year. In equation (10) and (11) σ(x) is the dispersion of the hour x and P(x) is active power during hour x. Two customers' consumption should always be summed as in equations (12) and (13), although their consumption profiles differed. (Koivuranta 2011)

$$P_{sum}(x) = P_1(x) + P_2(x) + \cdots + P_n(x) \qquad (12)$$

Where

$P_{sum}(x)$ is the sum of customers' mean powers during hour x

$P_n(x)$ is the mean power of a customer during hour x

In equation (12) the values of active power of each hour are summed. The dispersion curves are summed quadratically for each hour of a year.

$$\sigma_{sum}(x) = \sqrt{[\sigma_1(x)]^2 + [\sigma_2(x)]^2 + \cdots + [\sigma_n(x)]^2} \qquad (13)$$

Where

$\sigma_{sum}(x)$ is the square root of quadratic sum of customers' consumption's dispersion during hour x

$\sigma_n(x)$ is the Nth customer's consumption's dispersion during hour x.

The combined power and dispersion curves, equations (12) and (13), are processed as if they were only one customer. A case study was performed with temperature dependency model. It was used for predicting customers' peak powers with temperature correction for office buildings in Keilaniemi area. Two years AMR data was used for the study. The peak powers estimated with the PowerGrid program using old index series differed 23,5 % from actual values, whereas the standard error of values estimated with temperature correction model was only 9,7 %. In conclusion, the standard error was 142 % smaller than with PowerGrid program. The standard error was 11,1 % when presuming that the peak powers are equal to the values corrected with temperature correction model, but it is noteworthy that this kind method's prediction accuracy is reduced when combining different customers' consumptions together. Presently, PowerGrid calculation results are in fact even more incorrect, because in this inspection, PowerGrid was allowed to use 2010's actual energy consumptions. Whereas this new method forecasted electricity consumption of every hour of the year based on temperature data and after that, the new index model method was applied in order to predict the peak powers of the year. Also PowerGrid's present results are supposed to represent the 95% exceeding probability, when in fact the results were too low even to represent 50% exceeding probability. The percentages are the same for a single customer and for bigger groups. (Koivuranta 2011)

The most important thing for a DSO in the calculation of consumption profiles is the best possible ability to predict the peak power. The network has to be designed to endure its peak power. Moreover, the losses and voltage drop is tightly connected to peak power and to the hours when power level is high. Not all hours of a year are equally significant, hence the purpose is to choose a consumption profile, which depicts best the customer's consumption, stressing the most significant hours, the ones with highest power.

4.3 Potential for demand response on detached houses with electric heating

Consumption variation is a problem, because it causes network losses and aging of transformers. In figure 4.7 is shown the hourly load variations of Finland's and Sweden's total consumption proportionally. One hour's power is proportional to the two-day average power of the country. The time period is 23. – 24.2.2010. On the horizontal axis are the hours and on the vertical are the proportional values. The area of both curves is equal, because then the different total power levels do not affect on curve shapes and then they are comparable. It can be seen that during winter days the load variation is remarkably higher in Sweden than in Finland.

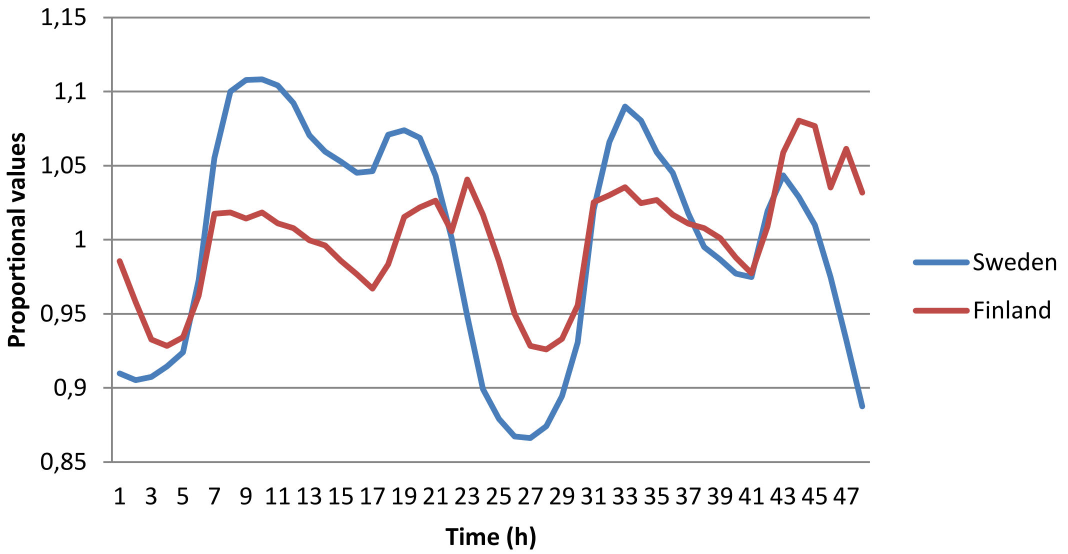

Figure 4.7. *Proportional hourly load consumptions in Finland and Sweden from a two-day period (Nord Pool Spot 2011).*

In Finland the transmission losses on the national grid were 1,5 % and in Sweden 2,6 % in 2009. The percentage of distribution losses is even higher, but the real exact amount is not known. The difference between these two countries can partly be explained by reviewing the figure 4.7. The loads are divided more evenly into different hours in Finland than in Sweden. If the consumption is more even, it will result in smaller losses. There are also other reasons for higher distribution losses in Sweden than in Finland, for example different voltage levels. In Sweden, the power level goes lower at night than in Finland, because there is not much load control for hot-water tanks. One reason for the lack of load control in Sweden is that the proportion of generation techniques is different from Finnish. The proportions of electricity generation techniques in

Nordic countries are presented in figure 4.8. In Sweden, roughly half of electricity is produced by nuclear power and another half with hydropower. The large amount of hydropower generation has diminished the need for controlling the load usage on a large scale at night, because water power generation can adjust to power variations quickly and the electricity producers will get the best profit when the spot market price is the highest. Normally it is the highest at daytime when the power consumption is the highest. There have been night tariffs available in Sweden at some scale previously, but currently the trend is to abolish the night tariffs. Not all DSOs have provided the night tariffs in Sweden so far in all areas, whereas in Finland all DSOs provide the night tariff. In Finland, the second evening peak at 10 pm and higher consumption compared to Sweden at night is explained by the fact that there is remarkable amount of electric space heating on. It will therefore reduce the daytime peaks notably compared to the Swedish values. The average acquisition cost of loss energy is about 3 c/kWh. The network losses differ highly between different Finnish DSOs, because the operating environment varies in different parts of the country.

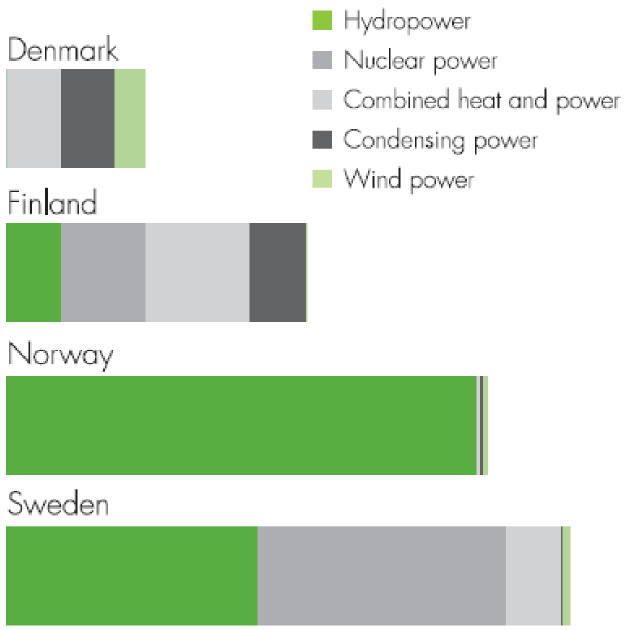

Figure 4.8. *The electricity generation techniques in Nordic countries (Svensk Energi 2010).*

In Finland 36 % of new detached homes have electric heating system. In 2009 Swedish detached homes 13,1 % used direct electric heating as only heating form. In that figure is also included air-source heat pumps. 14,2 % had immersion heater. 21,9 % of detached homes used combination of biofuels and electricity. (Statens energimyndighet 2011)

The curves in figure 4.9 depict the consumption of customers with different electric heating systems during the first 2-week period's weekday of a year. In the horizontal axis, for example, hour one represents the proportional consumption between 00:00 – 01:00. The three different consumption profiles are made from three different customers. The curves are proportional to one year's consumption, meaning that the area of each curve is 8,76×10^{7} in a year. One curve is done from one customer's consumption, because the peak load would be calculated too low if the consumption profiles of several customers were summed together. Previously done consumption profiles in Finland were made by averaging customer groups' consumption. Because of this, the actual peak power is higher than the one calculated with old consumption profiles. Especially when being calculated only a few consumption points, the peak power was too low. The old consumption profiles are presented in (Jalonen et al. 2003). The customers that have fully storing electrical heating have proportionally less consumption at daytime than other customers do. The example day was a cold winter day, therefore the consumption was very high until 7:00. Normally the hot-water tanks are not on the whole night.

2-week indexes can be used to predict consumption for a certain day and hour. Average power of customer *i* during hour *t* is

$$P_{it} = \frac{W_i}{8760} \times \frac{k_{i2t}}{100} \times \frac{k_{it}}{100}$$

Where
P_{it} is customer *i* 's power during hour *t*
W_i is year energy of customer *i*
k_{i2t} is 2-week index for customer *i* during hour *t*
k_{it} is hour index of customer *i* during hour *t*

The 2-week index for one customer is calculated as follows: average of the energies of all hours from 2-week's period is calculated. Then it is divided with the average power of the year.

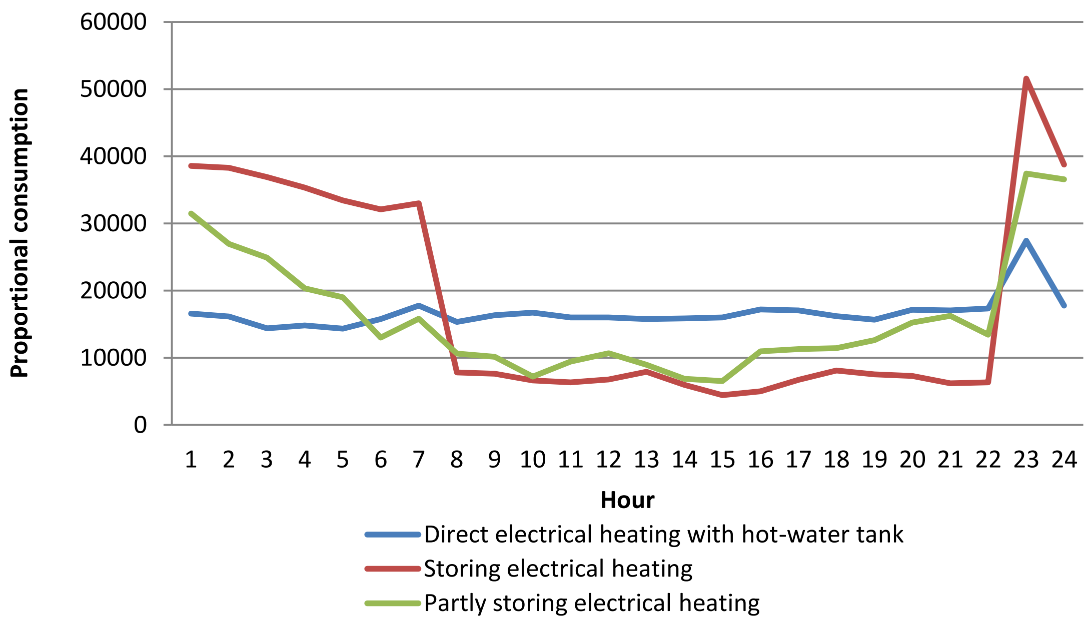

Figure 4.9. *Proportional consumption of three different customer types on a winter day*

In figure 4.10 it can be seen that there is a major power peak in the evening at 22:00 when the hot-water tanks are switched on and the need of high power level is very short in summer time.

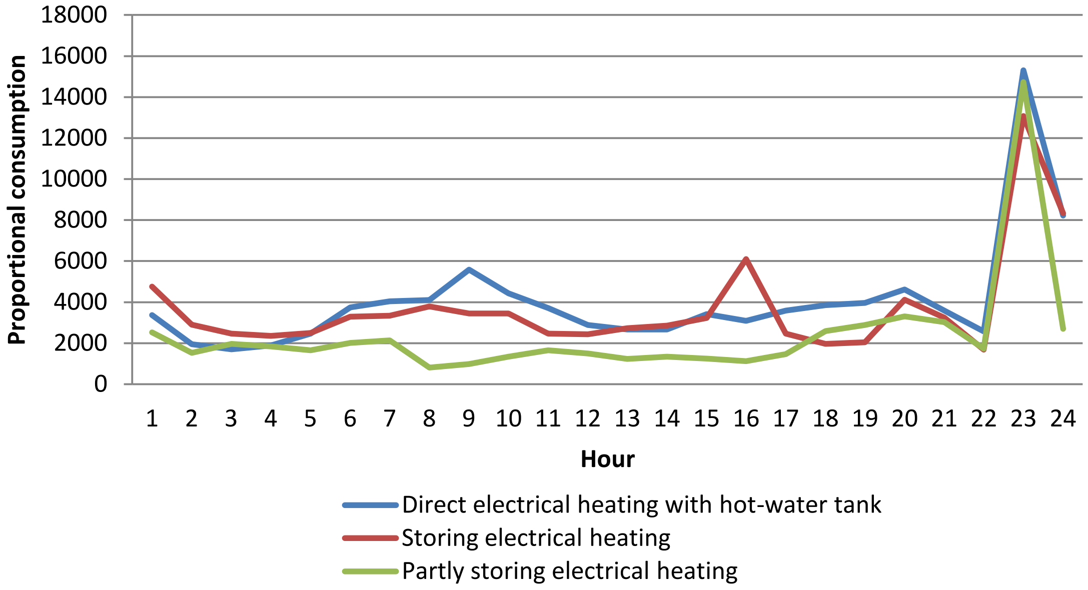

Figure 4.10. *Proportional consumption of three different customer types on a summer day*

Figure 4.11 shows how much the power level varies between different months in Finland. Temperature variation is the most important reason to fluctuation in power level. The indexes were calculated from AMR data.

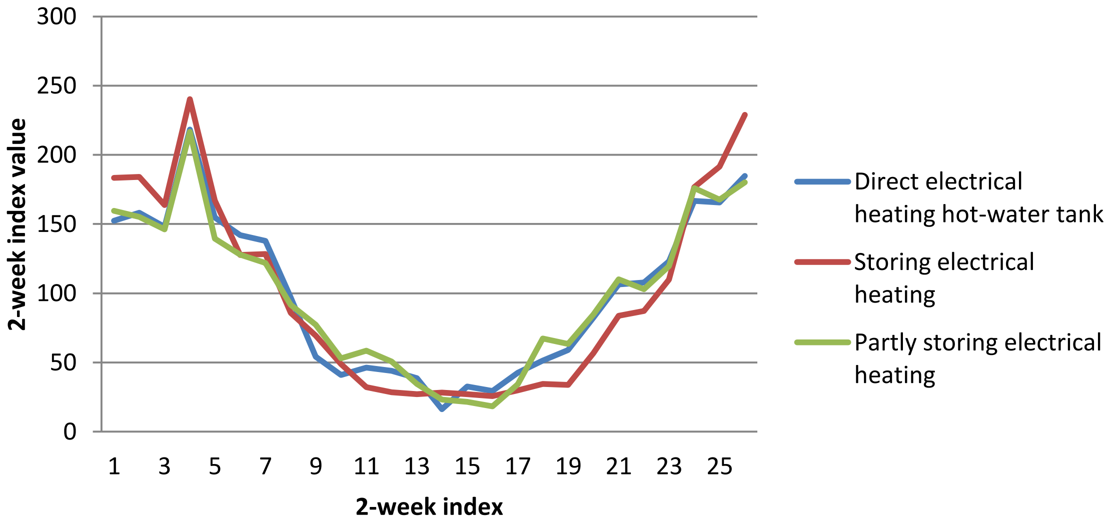

Figure 4.11. *The 2-week indexes of three different consumption profiles during a year*

There is a great deal of potential for demand response in detached houses with electrical heating. Especially the customers who have fully or partly storing electric heating have more easily controllable loads. On the other hand, the high peak demand in the evening causes much distribution losses, therefore all the hot-water tanks with nighttime tariff in Fortum's network region will be switched on in stages in future, but the load control should be done even later at night than planned. The potential of controllable loads was studied in (Jussila & Koivuranta 2010). The potential of different customers was calculated using load curves and PowerGrid program. Several feeders were studied. The potentially gained power was calculated by cutting the connection fuse with software fuse 75 %, 50 % and 25 %. Figure 4.12 shows how much power can be gained in a medium-voltage feeder if the connection fuses are cut with different percentages from detached houses with electric heating. In wintertime, the potential is naturally much higher, circa 1 MW potential in January with 75 % cutting as seen from figure 4.13. The potential is only circa 0,3 MW in July. If the main fuses are cut only 25 %, there is only minor reduction in loads, meaning that the main fuses of detached houses are commonly oversized. The cutting potential of different customer types and more research results about controllable loads can be studied from (Jussila & Koivuranta 2010).

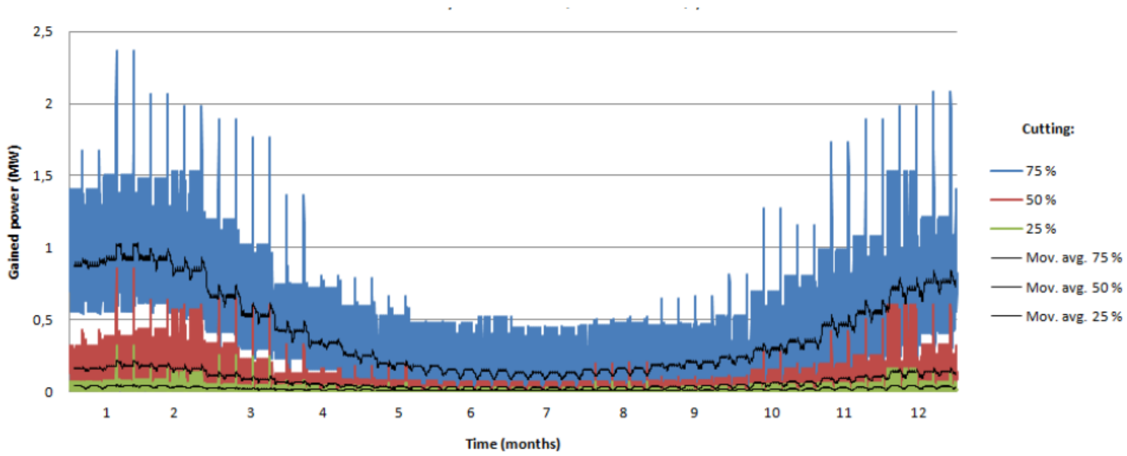

Figure 4.12. *The potential of a feeder, where the connection fuses of detached houses with electric heating was cut (Jussila & Koivuranta 2010).*

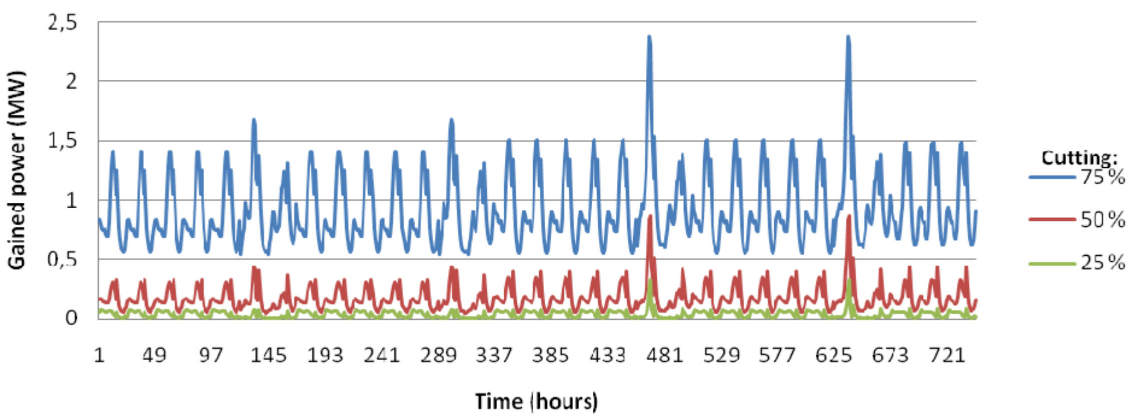

Figure 4.13. *The cutting potential of detached houses on a feeder in January (Jussila & Koivuranta 2010).*

5 POTENTIAL NETWORK TARIFFS

The new tariffs that are presented in this chapter were designed using both the existing consumption profile of detached house with storing electric heating and actual meter reading data. The following tariffs are not in use as such in any network company at the moment. They are evaluated based on the need to modify the consumption behavior so that the grid would be used as effectively as possible. The effective usage means using power as evenly as possible. The new tariffs are designed with the principle that the yearly payment would be a bit higher than with old tariff if the customer uses electricity as previously. On the other hand, if the customer changes their consumption to more affordable hours, their electricity bill's grid fee will become smaller. On the other hand, the revenue should not be too low either. In chapter 6 the revenue comparison is presented in more detail and the principle how AMR data was used in tariff design.

The design of tariffs was started with estimating the average yearly consumption of a house with electrical heating and calculating the probable peak power. The figures were used to roughly estimate the suitable yearly payment for a customer. After that, the yearly payment was calculated more precisely using a customer's one-year AMR consumption data. If a customer's yearly electrical energy consumption is 20 MWh and they have an over 300 liters hot-water tank and the main fuse is 3×35 A, with 50 % probability the value for a year's highest peak power is 8 kW. At nighttime and in daytime the probable peak power is 6 kW and in the evening it is 8 kW as mentioned above. The figures are calculated using Gaussian distribution, active power load curves and deviation curve. The theoretical 3-phase peak power is 24,2 kW with a 3×35 A main fuse. However, it is very hard to reach that power level in reality.

Electricity tax is charged of distributed energy and it is 0,0209469 €/kWh. In the following tariff models the annual electricity consumption is presumed to be approximately the same, hence the electricity tax will stay constant. Only the time of use will differ. Electricity tax is not included in the calculation in this chapter and on chapter 6. The amount of basic charge is dependent on the main fuse size in most of the cases. Nighttime tariff that has been used in calculations in this chapter and chapter 6 is the nighttime tariff (*Yösiirto* in Finnish) in FSS price list and similarly general distribution is the same as (*Yleissiirto*). Both of them are presented in *appendix 3*.

5.1 New network tariffs

This chapter will present the tariffs that were considered potential tariffs to be used in future. In chapter 6 is analysis of the most potential tariffs, which should be revised more profoundly. In chapter 5.3 is a calculation of how individual customer's change in consumption caused by new tariffs effects on their peak power, caused losses and costs, and how it correlates with overall consumption in Finland.

Figure 5.1 shows how the tariff design procedure goes in Fortum. First, the pricing team has a mandate to change prices, after that, different analyses are done. Calculations for type customers follow after analyses. Finally, risk analysis is performed before decision making. The tariff design procedure in designing new network tariffs for this thesis focused on analysis, calculations and risk analysis. The procedure how the new tariffs that are presented in chapters 5.1.1 – 5.1.6 were designed and chosen to this thesis went as follows. First, competitor analysis was done from demand response point of view. Then different tariffs that are being used in several distribution companies were compared. After that, AMR data was analyzed. New consumption profiles were done from the new data and a consumption profile selector was designed. Consumption profile selector was designed to choose the best consumption profile for a customer based on their AMR consumption data. AMR data analysis gave information about peak hours. Electricity consumption from peak hours should be reduced, so it gave incentive to set higher prices to peak hours. The peak hours were checked from household customers data and also from the whole country level. Several different tariffs were ideated and from those the ones that could have the best steering impact and also the ones that are quite easy to understand were chosen to further development.

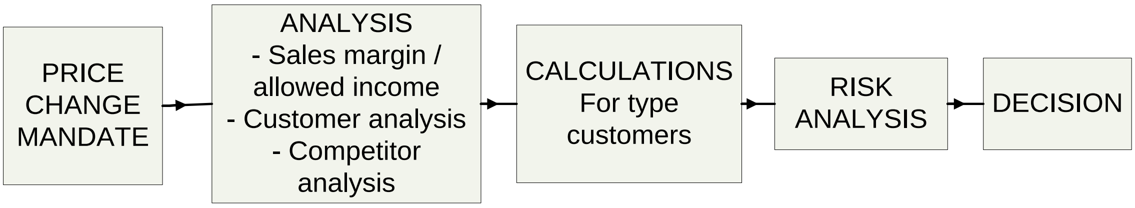

Figure 5.1 *Tariff design procedure in Fortum*

Further development consisted the analysis of how big the basic charge should be and which other components should be included. The combinations of energy based fee and power fee were analyzed. Then the new prices were changed to a type customer, from their data was analyzed the yearly payment level. If the yearly payment was too low or too high compared to original tariff, the prices were iterated until the level was suitable. Elasticity model was also used to model customer behavior. Network calculations were performed so that with elasticity modified consumption profiles were changed to customers who previously had nighttime tariff. The results from network calculations are presented in chapter 6.

5.1.1 Annual power tariff

The distribution charge is at night 0,011 €/kWh and at daytime it is 0,0279 €/kWh. The basic charge is relatively small, 120 € in a year with 3×35 A main fuse. The basic charge for other fuse sizes is presented in table 5.7. Prices are also shown in table 5.1. It was assumed that the yearly share of daytime distribution is 7 MWh and nighttime 13 MWh. The power charge is based on the maximum power in a year, meaning the highest consumed energy in an hour. The charge per every started kW would be 45 €. If the highest power were 8 kW, the power charge would be 360 € in a year. The aim of the tariff is to make people consider how much loads they use in the same time, so they are encouraged to follow their peak power. A drawback is that it is not interactive, because the inspection period is one year. This tariff is not well comparable between different tariffs. The reason is that elasticity calculation requires price for every hour of the year, whereas in annual power tariff the billing principle is the highest consumed energy during a single hour in yearly level.

Table 5.1. *Annual power tariff*

Time	Energy price (€/kWh)	Power charge (€/kW)
07:00 – 22:00	0,011	45
22:00 – 07:00	0,0279	

A modification of this tariff could be that there is a small free power portion. The free power portion could be for example 2 kW. Whereas, in this modified tariff the power increase will affect stronger to the electricity bill. For example, the price for each kW could be 60 €. Then the sum would still be the same, 360 €, if the peak power stays the same.

5.1.2 Three-time power tariff

The three-time power tariff is purely based on peak powers (€/kW). However, the electricity tax is charged based on the distributed energy (€/kWh). There are three time sections per day in which the limit for power charge differ. There are different tariffs for summer and winter period, because the electricity consumption is higher during the wintertime in Finland. Inspection periods are summer and winter (November – March). Price examples for summer period are 7 €/kW at night, 10 €/kW at daytime and in the evening. In winter period the prices would be 35 €/kW in the evening, at daytime 25 €/kW and at night 10 €/kW. The prices are listed in table 5.2. Basic charge would be 240 € per year and it is the same for all main fuse sizes. The powers are not instantaneous powers; the power is the highest average power of an hour.

Table 5.2. *Three-time power tariff*

Time of day	Power charge summer (€/kW)	Power charge winter (€/kW)
Day	10	25
Evening	10	35
Night	7	10

A drawback of this tariff is that it is not very interactive without proper information for the customer. They should know instantaneously how much they have used power every hour. A solution for this could be in-home display. An advantage is that the tariff is easy to understand and quite simple. It motivates people not to put all their devices on at the same time. Hence, the alternation of loads should be stressed more. Proper customer education is important, since they should be taught what does, for example, kW and kWh mean. Moreover, if a customer exceeds some power level, it does not matter how much the customer consumes electricity later in that time of day in the same inspection period. The good thing for the DSO is that the customer pays on the grounds that how much the network is loaded in peak periods, because the network is designed for certain load level.

5.1.3 Three-time energy and power tariff

There are three different price periods in a day in this tariff. Off-peak (night) price is 0,01 €/kWh, mid-peak (day) 0,015 €/kWh and on peak (evening) 0,03 €/kWh. There is also power charge: at nighttime 8 €/kW, 15 €/kW at daytime and 20 €/kW in the evening. The prices are also shown in table 5.3. Basic charge would be 100 € per year and it is the same for all. The loads are encouraged to be used during the time when there will be highest savings from reduced power losses. The disadvantage is that the tariff is not interactive, because the inspection period is one year.

Table 5.3. *Three-time energy and power tariff*

Time of day	Power charge (€/kW)	Energy component (€/kWh)
Day	15	0,015
Evening	20	0,03
Night	8	0,01

5.1.4 Multiple time energy-based tariff

This tariff is based on energy-based component and basic charge. The basic charge is relatively low, 140 €/year for 35 A connection point. In that case, customers will understand that the bill consists only of their energy usage. The basic charge for other fuse sizes is presented in table 5.7. There are five differently priced time sections in a day. The aim of the tariff is to equalize the load consumption from on-peak hours to off-peak hours, because in that way there will be decrease in network losses, the peak powers decrease and from that reason CO_2 emissions decrease. On the other hand, there might develop new smaller load spikes and there is no outright power limitation. Some customers might not like the idea of high electricity price in the evening time, because they are home then and they would like to use their appliances. Energy prices with multiple time energy-based tariff are shown in table 5.4.

Table 5.4. *Multiple time energy-based tariff, basic charge is excluded*

Time	Energy price (€/kWh)
00:00 – 7:00	0,0171
7:00 – 8:00	0,0388
8:00 – 16:00	0,0319
16:00 – 18:00	0,0388
18:00 – 00:00	0,0547

5.1.5 Real-time pricing (RTP) of losses tariff

Benefits of real-time pricing for DSO are that it is interactive and the prices follow the real costs caused by network losses. A challenge is that customers do not want to follow electricity prices every day, because they will not find it interesting and useful. There is the same challenge of customer participation also for retailer's spot tariffs. Home automation is one solution to RTP implementation, because then the customer would not have to take care of using electricity at right time. A challenge is to install home automation to old houses, whereas home automation is a more attractive choice for new buildings. This suggested RTP tariff is designed on the principle that the revenues cover the proportional network loss expenses caused by an average household customer. In addition, transformer aging and transformer losses are highly connected to peak power and to the hours when the electricity consumption is high. Basic charge is 300 €/year for 35 A connection point. The hourly prices of electricity of one-year period are shown in Figure 5.2. and the equation for the prices is (14). There are conflicts between the DSO's and retailer's interests concerning RTP, which are explained more profoundly in chapter 3.3.1. Firstly, retailers would want that RTP is based on spot-price, but for DSO there is no benefit from spot pricing, more like troubles caused by excessive loading if notable amount of load is put on at the same time.

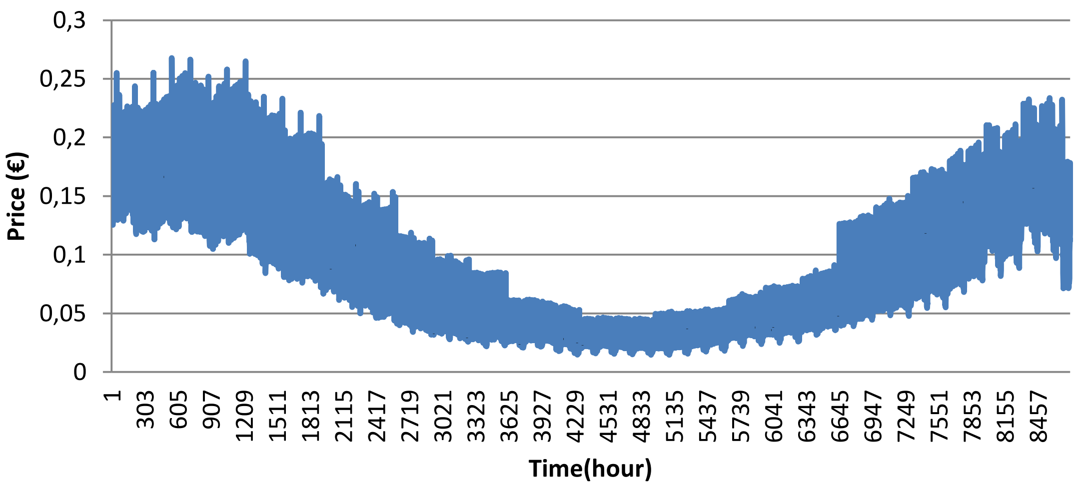

Figure 5.2. *The real time price of electricity (€/kWh) for a customer during a year when the determining factor of price is network losses*

Figure 5.3 depicts the variation in price during one example winter day. In horizontal axis hour 1 means the time between midnight and 1 am. The daily variation in price is about 0,1 € in the example day. It is relatively high, but it needs to be significant if some kind of change in consumption behavior is wanted. Although RTP loss tariff allocates the costs right, it is not the best possible tariff to direct the customer's consumption behavior as can be seen from table 5.9.

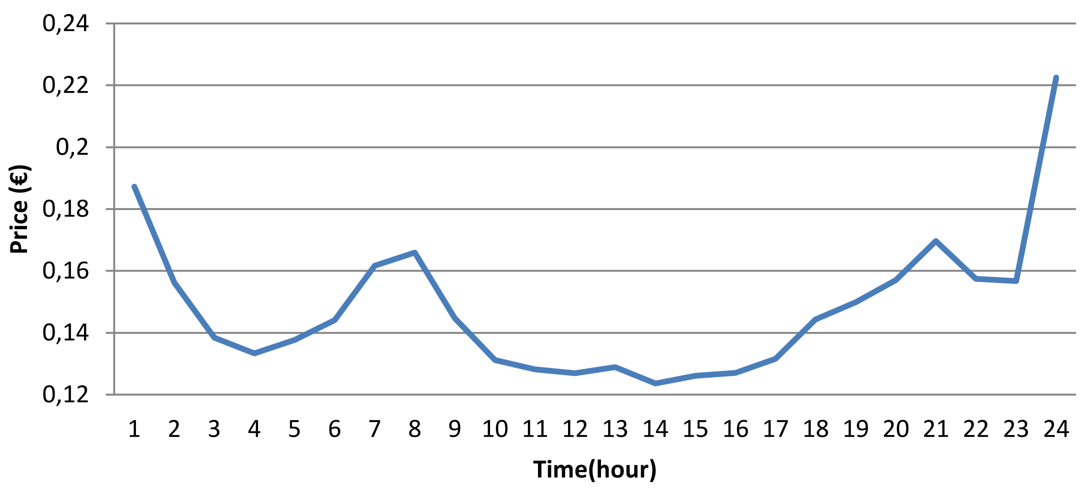

Figure 5.3. *The RTP prices during an example winter day*

The equations which were created for the purpose of calculating RTP prices are presented below.

$$N(x) = a\left(\frac{P_{FI}(x)}{P_{FI(max)}}\right)^k + b\left(\frac{P_{Substation}\ (x)}{P_{Substation(max)}}\right)^l + c\left(\frac{P_{Sec\ substation}(x)}{P_{Sec\ substation(max)}}\right)^m \qquad (14)$$

$$a\left(\frac{P_{FI}(x)}{P_{FI(max)}}\right)^k = \alpha$$

$$b\left(\frac{P_{Substation}\ (x)}{P_{Substation(max)}}\right)^l = \beta$$

$$c\left(\frac{P_{Sec\ substation}(x)}{P_{Sec\ substation(max)}}\right)^m = \gamma$$

Where

$N(x)$ is price during hour x.

a, b and c are iterated constants, which describe the proportions in which part of network energy losses are caused.

$P_{FI}(x)$ is power in Finland during hour x.

$P_{FI(max)}$ is the year's maximum power in Finland.

$P_{Substation}\ (x)$ is the power of the Finnish primary substation network that is suitable for the study, during hour x.

$P_{Substation(max)}$ is the year's maximum power of the Finnish primary substation network that is suitable for the study.

$P_{Sec\ substation}(x)$ is the power of an average Finnish secondary substation network during hour x.

$P_{Sec\ substation(max)}$ is the year's maximum power of an average Finnish secondary substation network.

k, l and m are iterated constants and all of them are approximately 2, since losses are quadratic to current.

α is the proportional HV network losses and investment savings of peak power reduction.

β is the proportional MV network losses and investment savings of peak power reduction.

γ is the proportional LV network losses and investment savings of peak power reduction. The proportions of α, β and γ are known.

If α, β and γ are divided with the same constant, as a result will be got which share of losses come from HV, MV and LV networks.

5.1.6 Software fuse tariff

This tariff uses a software fuse in determination of power levels. The functionality of the software fuse is described more profoundly in chapter 4.1. If the current exceeds the determined software fuse limit, the consumption that is over the limit is saved to another tariff register. The basic charge would be smaller than in present nighttime tariff. The basic charge, for instance, is 150 €/year for 3x35 A connection point, whereas currently it is 378,72 €/year in FSS area for nighttime tariff. The basic charge for other fuse sizes is presented in table 5.7. The software fuse limit is determined based on the main fuse size. The power limit is 5 kW for connection point with 3×35 A main fuse and 3,29 kW for 3×25 A main fuse. The power limit is calculated with equation (15). The equation (15) is created empirically for this thesis.

$$Power\ limit = \left(6 \times \left(\frac{Fuse\ size\ (A)}{35\ A}\right) - 1\right)\ kW \qquad (15)$$

If the limit is exceeded in daytime, the distribution fee is 0,0504 €/kWh higher from the exceeding part. In daytime the tariff is 0,036 €/kWh and at nighttime 0,012 €/kWh. This is also shown in table 5.5. For example, when the limit is exceeded in daytime, the price is 0,0504 € per exceeded kWh plus 0,036 €/kWh below the limit. The hot-water tanks are switched on after 00:00 in random time window during an hour. It is also possible to insert power cut off functionality, meaning that if the software fuse limit is constantly exceeded, the power will be cut off after a configurable time. It will be possible that the meter unit sends an on/off command to a Zigbee based device when the software fuse limit is exceeded. Although this functionality is possible to implement, the customers might not find it interesting, because likely they do not want any unnecessary interruptions in electricity usage. An in-home display is necessary to inform the power level for the customer. It would not be sensible that the customer gets information only in monthly bill, whereas the customer should get a notice if the power level is about to exceed. Then the customer could react and switch off some unnecessary appliances to prevent to exceed the predetermined power limit.

Table 5.5. *Software fuse tariff, basic charge is excluded*

Time of day	Energy component (€/kWh)	Extra payment after exceeding the limit (€/kWh)
Day	0,036	0,0504
Night	0,012	0

5.2 Elasticity

Each customer group reacts differently to price changes. This is characterized by the price elasticity of demand. It describes how much power is expected to change as a result of the change in price. Loads can be two types:

- *Inelastic loads* are not much affected by changes in price, elasticity is close to zero
- *Elastic loads* are very sensitive to price changes, elasticity can be very large.

Belonogova et al. (2010) determined the power peak reduction using equation (16)

$$\Delta P_{ij} = e \times \frac{\Delta C_{ij}}{C_i} \times P_i \tag{16}$$

Where
ΔP_{ij} is power change from hour i to hour j, MW.
e is price demand elasticity of a customer group, (p.u.):
change in consumed energy in percentages divided with change in price.
ΔC is price change against the reference price, €/MWh.
C_i is system price of the hour i, €/MWh.
P_i is power in the hour i, MW.

There are some reasons why equation (16) is not fully suitable for being used properly in modeling the real elasticity of electricity customers. One reason is that the total consumption of a day does not change due to elasticity. The loads are only shifted to other hours, not reduced totally. Elasticity in equations (16) and (17) is a bit different. That is why the equations (17) and (18) were created. It is different thing if the increase of electricity price decreases the total consumption. Energy saving has to be researched separately. A new tariff was created using elasticity, so that the new consumption was set fixed to all hours. It was assumed that elasticity is the same in every hour, which is not true in reality. Then for each tariff the elasticity was set to different values: 0,1; 0,2 and 0,3. As consumption was set the old consumption and as tariff was set the present tariff. Equations (18), (19), (20) and (21) are combined to equation (17). The result of it is equation (22), which calculates the power consumption of a customer.

$$P_{new,p} = \frac{C_{old,p} - C_{new,p}}{C_{old,p}} \times e \times P_{old,p} \tag{17}$$

$$P_{new} = P_{average} \times P_{new,p} \tag{18}$$

$$P_{old,p} = \frac{P_{old}}{P_{average}} \tag{19}$$

$$C_{new,p} = \frac{C_{new}}{C_{new,average}} \tag{20}$$

$$C_{old,p} = \frac{C_{old}}{C_{old,average}} \tag{21}$$

$$P_{new,hour\ i} = P_{average}\left(\frac{\frac{C_{old}}{C_{old\ average}} - \frac{C_{new}}{C_{new\ average}}}{\frac{C_{old}}{C_{old\ average}}} \times e \times \frac{P_{old}}{P_{average}} + \frac{P_{old}}{P_{average}}\right) \tag{22}$$

Where

$P_{new,p}$ is proportional power of hour *i* with new tariffs, proportional to the average of inspection period

$C_{old,p}$ is proportional price of hour *i* with old tariffs

P_{old} is power during hour *i* with old tariffs

$P_{old,p}$ is proportional power during hour *i* with old tariffs

P_{new} is power during hour *i* with new tariffs

$C_{new,p}$ is proportional price of hour *i* with new tariffs

C_{new} is price of hour *i* with new tariffs

$C_{new,average}$ is the average price of the inspection period

C_{old} is price of hour *i* with old tariffs

$C_{old,average}$ is the average price of the inspection period

$P_{average}$ is the average power of the inspection period

If software fuse tariff is in use, C_{new} is calculated as follows:

If $P_{old} > P_{limit}$, then

$$C_{new} = \frac{(3{,}6\ c/kWh \times P_{limit} + (P_{old} - P_{limit}) \times (3{,}6 + 5{,}04)\ c/kWh)}{P_{old}}$$

else

C_{new} = 3,6 c/kWh
Where
P_{limit} is predetermined power limit that is set to software fuse

The total yearly consumption does not change due to elasticity, it is just moved to another period. The inspection period is, for example, one day. If there are critical days, the length of inspection period has to be extended. Since the total consumption does not change, equation (17) has been created, which corresponds equation (16). In equation (17) the power consumption is proportional. Therefore, the prices have to be proportional too. Proportional price is the price of an hour divided by the average price of an inspection period. In equation (16) has been presumed that elasticity is the same for every hour. It is not true in reality, because elasticity is dependent on the hour of the day. Therefore, a new model was created, which is equation (22). In the new equation (22) the system price is never negative, whereas in equation (16) it goes negative if the desired power change is high enough. The customers' actual elasticity cannot be researched until there are new tariffs in use. Proposal of a pilot area arose, where elasticity could be researched. Then it would be possible to create tariffs that optimize electricity consumption. If there are enough elastic loads, theoretically the load consumption could be made fully even by using suitable tariffs.

5.3 Comparison between potential tariffs

Table 5.6 shows the existing tariffs (general distribution and nighttime) and designed tariffs without basic charge. RTP loss tariff is excluded from that table, since the price is different in each hour. At nighttime the extra payment with the software fuse tariff is 0 €, because it motivates customers to shift electricity usage from evening to later time when there is much capacity available in the network.

Table 5.6. *The present tariffs for FSS customers and designed tariffs without basic charges*

<table>
<tr><th rowspan="2"></th><th colspan="2">Present tariffs</th><th colspan="9">Designed tariffs</th></tr>
<tr><th>General distribution</th><th>Nighttime</th><th colspan="2">Annual power tariff</th><th colspan="2">3-time power</th><th colspan="2">3-time energy & power</th><th>Multiple time</th><th colspan="2">Software fuse</th></tr>
<tr><th>Time</th><th>c/kWh</th><th>c/kWh</th><th>c/kWh</th><th>€/kW</th><th>€/kW summer</th><th>€/kW winter</th><th>c/kWh</th><th>€/kW</th><th>c/kWh</th><th>c/kWh</th><th>extra c/kWh</th></tr>
<tr><td>0:00</td><td rowspan="24">2,79</td><td rowspan="7">1,82</td><td rowspan="7">1,1</td><td rowspan="24">45</td><td rowspan="7">7</td><td rowspan="7">10</td><td rowspan="7">1</td><td rowspan="7">8</td><td rowspan="7">1,71</td><td rowspan="7">1,2</td><td rowspan="7">0</td></tr>
<tr><td>1:00</td></tr>
<tr><td>2:00</td></tr>
<tr><td>3:00</td></tr>
<tr><td>4:00</td></tr>
<tr><td>5:00</td></tr>
<tr><td>6:00</td></tr>
<tr><td>7:00</td><td rowspan="15">2,79</td><td rowspan="15">2,79</td><td rowspan="11">10</td><td rowspan="11">25</td><td rowspan="10">1,5</td><td rowspan="10">15</td><td>3,88</td><td rowspan="17">3,6</td><td rowspan="17">5,04</td></tr>
<tr><td>8:00</td><td rowspan="8">3,19</td></tr>
<tr><td>9:00</td></tr>
<tr><td>10:00</td></tr>
<tr><td>11:00</td></tr>
<tr><td>12:00</td></tr>
<tr><td>13:00</td></tr>
<tr><td>14:00</td></tr>
<tr><td>15:00</td></tr>
<tr><td>16:00</td><td rowspan="2">3,88</td></tr>
<tr><td>17:00</td><td rowspan="7">3</td><td rowspan="7">20</td></tr>
<tr><td>18:00</td><td rowspan="6">10</td><td rowspan="6">35</td><td rowspan="6">5,47</td></tr>
<tr><td>19:00</td></tr>
<tr><td>20:00</td></tr>
<tr><td>21:00</td></tr>
<tr><td>22:00</td><td rowspan="2">1,82</td><td rowspan="2">1,1</td></tr>
<tr><td>23:00</td></tr>
</table>

Table 5.7 depicts the basic charges of existing tariffs and the basic charges of some of the designed tariffs. The basic charge is 100 € for three-time energy & power tariff and 240 € for three-time power tariff with all fuse sizes.

Table 5.7. *The basic charge for each tariff in different fuse sizes in a year.*

Fuse size (A)	Nighttime (€) (*Yösiirto*)	General distribution (€) (*Yleissiirto*)	Multiple time (€)	Software fuse (€)	Loss RTP (€)	Annual power tariff (€)
16	159,72	131,76	100	100	150	100
25	203,28	174,24	120	100	225	120
35	378,72	306,12	140	150	300	140
50	660,6	528,72	200	325	400	200
63	1028,4	822,72	300	400	550	300

The calculations of consumption behavior change with different tariffs were performed so that the effect on grid state would be discovered. In table 5.8 the calculations were performed from the premise that consumption was based on load curve, whereas in the calculations in table 5.9 the consumption was based on AMR data. The load curve is number 300 of SLY load curves that are presented in (Jalonen et al. 2003). The results depict how individual customer's change in consumption that is caused by new tariffs effects on their peak power, caused losses and costs, and how it correlates with overall consumption in Finland. The total consumption does not change, only the time of use varies. In table 5.8. and table 5.9, general distribution tariff is the same as *Yleissiirto* in *appendix 2* and *3*.

The software fuse tariff is not included in table 5.8 because the peak powers are lower in load curves than in reality, hence it was not reasonable to model them with old load curves. From table 5.8 can be seen that the three-time energy & power tariff lowers most peak power and losses compared to other tariffs, also it decreases costs almost as well as the RTP loss tariff. The multiple time tariff is slightly less effective than three time energy & power tariff in reducing peak power and losses. The multiple time tariff is slightly better than three-time tariff in value 5 comparison.

Table 5.8. *The differences of several tariffs compared to nighttime tariff (Yösiirto), when consumption is based on load curve. Values 1 – 5 are described in text.*

	Value1	Value2	Value3	Value4	Value5
General distribution (*Yleissiirto*)	0,1	2,39 %	0,44 %	0,58 %	0,28 %
General distribution (*Yleissiirto*)	0,2	4,78 %	0,80 %	0,74 %	0,21 %
General distribution (*Yleissiirto*)	0,3	7,18 %	1,08 %	0,90 %	0,14 %
Multiple time tariff	0,1	6,22 %	0,87 %	0,69 %	0,47 %
Multiple time tariff	0,2	12,32%	1,43 %	0,95 %	0,58 %
Multiple time tariff	0,3	13,34%	1,70 %	1,22 %	0,69 %
3 time energy & power tariff	0,1	6,45 %	1,11 %	0,78 %	0,43 %
3 time energy & power tariff	0,2	12,78%	1,89 %	1,14 %	0,50 %
3 time energy & power tariff	0,3	16,91%	2,37 %	1,50 %	0,57 %
RTP loss tariff	0,1	3,07 %	0,94 %	0,95 %	0,29 %
RTP loss tariff	0,2	6,13 %	1,68 %	1,48 %	0,23 %
RTP loss tariff	0,3	9,19 %	2,22 %	2,01 %	0,16 %

Value 1 is elasticity, which is used in equation (22). All of the values are calculated with equation (22) using new tariffs with different values of elasticity. Value 2 means how much customer's peak power is reduced with new tariff compared to nighttime tariff. Value 3 represents how much theoretically losses that are caused by customer are reduced with new tariff compared to nighttime tariff. Value 3 is calculated from the extraction of quadratic sum of hourly power values, both from consumption behavior with nighttime tariff and the other quadratic sum is from the consumption behavior with new tariffs. The calculations were done without taking into account the network impacts of other customers' consumption behavior. The calculation of real value of losses would require network calculation of each part of network separately. Value 4 is an estimation of how much DSO's network expenses would decrease with new tariff compared to nighttime tariff. It is calculated with equation (14) by multiplying it with hourly power values with new consumption behavior, summing the values and extracting them with old consumption style power values that are multiplied with equation (14). Value 5 is the sum of the extractions of the customer's consumption with new and old tariffs multiplied by the total demand of electricity in Finland in every hour of a year. It is explained in equation (23).

$$Value\ 5 = \sum_{i=1}^{8760}\left[\left(P_{old,i} - P_{new,i}\right) \times P_{Finland,i}\right] \qquad (23)$$

Where

$P_{old,i}$ is customer's power during hour i with old tariff

$P_{new,i}$ is customer's power during hour i with new tariff

$P_{Finland,i}$ is Finland's power during hour i

The used example year was 2009 and Finland's consumption data from that year is collected from (Fingrid Oyj 2011). System price correlates highly with Finland's electricity demand. For example, if value 5 is negative, then the consumption is higher with the new tariff than with nighttime tariff when the Finland's electricity demand is high.

As can be seen from table 5.9, in which the values are calculated based on actual consumption data, a software fuse tariff will bring considerable reduction in peak power (column value 2) and timing of consumption is good for retailer too (value 5 is positive). With elasticity value 0,3 the peak power is reduced almost 25 %, which is a very significant result. The negative values in value 5 in general distribution and RTP loss tariff are explained by the fact that the consumption is shifted from nighttime to daytime, when the market price is high. When the inspection scope is only one customer and compared to nighttime tariff, all the tariffs reduce peak power. Although, it is not the case when the losses are inspected in larger inspection scope. Peak power reduction results in decreased losses, as well as in reduced network expenses. In the whole country level, nighttime tariff brings significant reduction in losses, although the losses could be even smaller if the starting time was staggered. Therefore, peak power issues cannot be evaluated unambiguously. The plans for staggering Fortum's customers' nighttime electric heating are presented in chapter 2.3.2.

Table 5.9. *The differences of several tariffs compared to nighttime tariff, when consumption is based on AMR data and the yearly energy is 22,8 MWh.*

	Value 1	Value 2	Value 3	Value 4	Value 5
General distribution	0,1	2,23 %	0,48 %	0,16 %	-0,06%
General distribution	0,2	4,48 %	0,88 %	0,33 %	-0,13%
General distribution	0,3	3,81 %	1,21 %	0,49 %	-0,19%
Multiple time tariff	0,1	5,99 %	1,21 %	0,29 %	0,11 %
Multiple time tariff	0,2	11,89%	2,09 %	0,57 %	0,22 %
Multiple time tariff	0,3	17,43%	2,66 %	0,84 %	0,33 %
3 time energy & power tariff	0,1	6,24 %	1,42 %	0,38 %	0,07 %
3 time energy & power tariff	0,2	12,38%	2,51 %	0,76 %	0,15 %
3 time energy & power tariff	0,3	18,24%	3,28 %	1,13 %	0,22 %
RTP loss tariff	0,1	3,09 %	0,96 %	0,53 %	-0,05%
RTP loss tariff	0,2	6,18 %	1,73 %	1,07 %	-0,11%
RTP loss tariff	0,3	7,94 %	2,31 %	1,60 %	-0,17%
Software fuse tariff	0,1	10,25%	1,13 %	0,12 %	0,19 %
Software fuse tariff	0,2	19,98%	1,66 %	0,24 %	0,37 %
Software fuse tariff	0,3	24,92%	1,65 %	0,35 %	0,55 %

In figure 5.4 and figure 5.5 are shown how much the customer should change their consumption behavior with different elasticity value and the used tariff is software fuse.

In the figures, blue line means what was the consumption of the example customer on January's second week in 2011. The 24-hour period is from 7:00 – 06:00 so that the changes at nighttime were shown more properly. In the calculation example, part of the consumption will be shifted to the next few hours if the price is lower in the following hours, not to previous hours although in reality customers could also do that. From the figures can be seen that the peak power has become lower and consumption is shifted to later time from evening peaks, which causes positive impacts on the network. Usually the highest peak is at 22:00, but on that day the customer had used more energy a couple of hours before that.

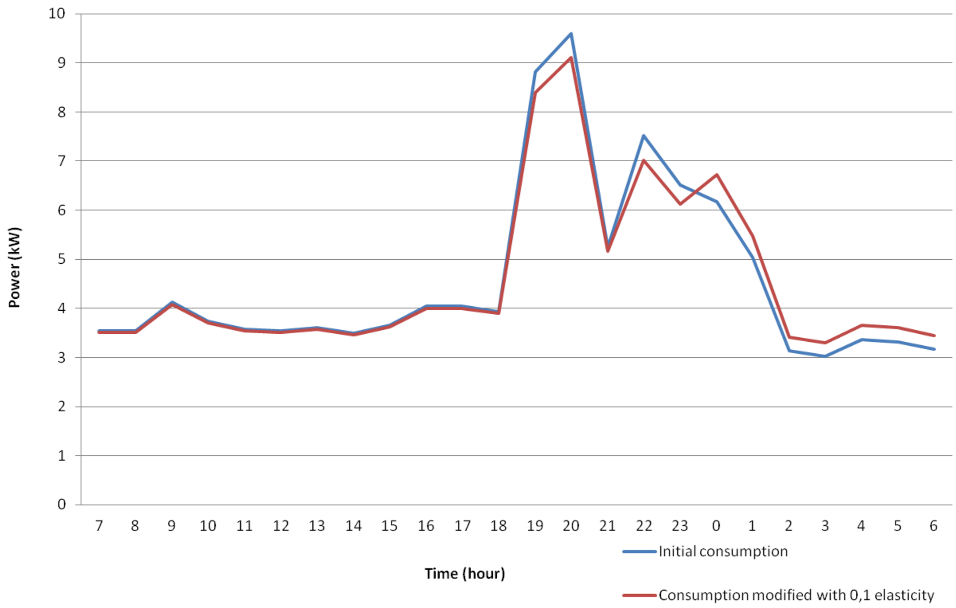

Figure 5.4. *Customer's calculated change in consumption with 0,1 elasticity value.*

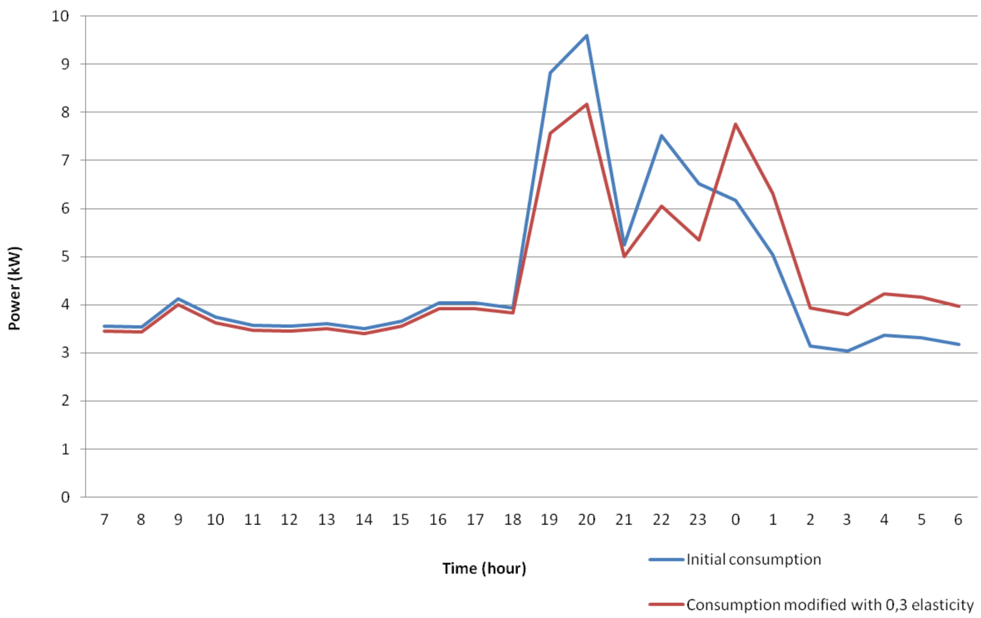

Figure 5.5. *Customer's calculated change in consumption with 0,3 elasticity value.*

6 THE ECONOMICAL EFFECTS OF NEW NETWORK TARIFFS ON DISTRIBUTION BUSINESS AND GRID INVESTMENTS

Energy saving actions, energy efficiency and distributed generation will reduce the amount of transferred energy. Therefore, the revenue of DSOs will decrease with present tariff structure. Mostly these actions will not effect on network's peak powers, therefore the expenses will not decrease. The changing operational environment drives the development of tariff structures, because the present tariffs are not capable of keeping the required income level. This is one factor why power tariffs should be available for household customers too.

6.1 Effects on grid investments and design

The main subtasks in distribution network planning are the estimation of future changes in consumption level in some particular area, optimizing the structure of MV network, the selection of transformer location and the determination of LV network structure. The follow-up calculations are done approximately once in a year for existing networks. In the calculations, the electrotechnical condition is estimated and the need for replacement investments is identified on the grounds of realized consumption level and network structure. Inspected issues are for example:

- Network losses in different sections
- Voltage drop in different sections
- The change in voltage level after different load increments
- The level of fault currents and their caused increments in hazardous and disturbance voltage
- Adequate size of fuses
- Load rate of distribution transformers

The following results in tables 6.1, 6.2 and 6.3 are based on network calculations from two different primary substations. The primary substations are situated in Salo and Espoo. In the Kisko primary substation in Salo the overall amount of connection points is 2184. The simulation was done with PowerGrid network calculation program. The network calculation was performed two times with PowerGrid program, once with the load curves that represent old consumption style and another time with load curves that represent consumption with new tariffs. The new load curves were made based on AMR data. First, the network calculation was performed so that an enhanced load curve was changed for the customers who have electric heating and electrically heated hot-water tank. The second calculation was performed similarly, except the new load curve was modified using elasticity model in equation (22) and the elasticity was 0,3 for every hour of the year. The used price signal is multiple time tariff, because elasticity model gives reliable estimations with it and multiple time tariff has good steering impact. The inspected area was the network of one primary substation. The calculated savings from losses is the difference between the initial state and the final state. The price for loss energy was assumed 0,03 €/kWh. The active power losses are determined from equation (24) and reactive losses from equation (25) (Lakervi & Partanen 2008). Savings per rural customer are around 30 € from network losses in a year. Long-term savings are 1423 €/customer from 30 years resulting from avoidance of reinvestments. The sum is high due to the rural structure of the grid.

$$P_h = 3I^2R \tag{24}$$

$$Q_h = 3I^2X \tag{25}$$

The savings per transformer are calculated by examining the load rate of transformers in certain primary substation network. First, a load rate limit, which indicates a satisfactory level, is selected. The transformers, which load rate exceeded 80 % were selected to be changed to one size bigger. The limit is 80 % instead of 100 %, because the electricity consumption increases in long run. The load rate of each transformer is compared after the network calculations. If the load rate was in its initial state higher than the selected load rate limit, and after consumption profile change it goes below the limit, there can become savings. The consumption profile was taylorized to represent the consumption with multiple time tariff. The number of transformers that changed to be under the limit after the consumption profile change are calculated. The transformers, which would have had to be changed before the tariff change were removed from the calculation. The estimated saving per transformer is calculated as follows. The price for the rest of the transformers that are needed to be changed was searched, both for the smaller and bigger size. Then the extraction of the prices was calculated and after that the average of extraction is calculated. The average is divided with the total number of transformers in that primary substation network. The used price of different sized transformers is the price that is informed in EMV's website. The implementation of demand response will effect on the transformer size requirement. One of 20 rural transformers could be one size smaller if the consumption was changed as desired. Changing the consumption profiles resulted in average reduction of 70 € in expectation value of a transformer price in areas where is relatively much detached homes with electric heating. There will be savings, because the transformers do not have to be changed or designed to be one size bigger.

Cross-sectional area of the cable is more dependent on the fault current protection requirements than on loading. The requirement for voltage level in Finland is 230 V ± 10 %, hence the phase voltage has to be over 207 V. Grounding on performed calculations, the decrease in peak powers increase voltage level. Tariffs are practically the only way to affect on customers' consumption behavior. 17 % of the customers who previously had too low voltage (under 207 V) changed to be above the required voltage level after changing modified consumption profile for them. The consumption profile was for detached homes with storing electricity heating and their hot-water tank is over 300 liters. The roughly estimated sum for reinvestment of a secondary substation's network is around 27 000 €. Reinvestment may contain the changing of overhead lines or cables to bigger size, changing of transformer to bigger size and change of protection devices. The variation of reinvestment costs is very high.

6.2 Effects on revenues

In table 6.1 it is calculated how one customer's yearly electricity bill's distribution payment change when the tariff is changed. The calculations were performed with three different elasticity values. The calculations are based on one customer's consumption data, which represents well the consumption of a house with electric heating. The reason why only one customer's consumption data is used is that if the average of many customers were used in the calculations, the probable peak powers would be lower than in reality. It is important for DSOs to predict the peak power as correctly as possible. The customer is from Tuusula pilot area, it has storing electric heating, main fuse size is 3×35A and uses electricity 22,8 MWh per year. 20 MWh is typical yearly consumption for a customer who has electrical heating. The yearly payment with nighttime distribution tariff using old consumption behavior is 913,5 € for the example customer.

Table 6.1. *Yearly payment of distibution fee with different tariffs and elasticy values.*

	Elasticity	Payment (€) with new tariff, new consumption behavior	Price difference between nighttime tariff and new tariff, new consumption behavior	Payment (€) with new tariff, old consumption behavior	Price difference between nighttime tariff and new tariff, old consumption behavior
General distribution	x	942,3	-28,73	942,3	-28,73
Multiple time tariff	0,1	908,6	4,92	920,9	-7,40
Multiple time tariff	0,2	896,5	17,04	920,9	-7,40
Multiple time tariff	0,3	884,6	28,97	920,9	-7,40
3 time energy & power tariff	0,1	888,0	25,57	918,8	-5,31
3 time energy & power tariff	0,2	881,2	32,34	918,8	-5,31
3 time energy & power tariff	0,3	850,5	63,02	918,8	-5,31
RTP loss tariff	0,1	911,9	1,62	916,0	-2,49
RTP loss tariff	0,2	907,8	5,73	916,0	-2,49
RTP loss tariff	0,3	903,7	9,83	971,0	-2,49
Software fuse tariff	0,1	899,3	14,20	915,4	-1,86
Software fuse tariff	0,2	883,8	29,72	915,4	-1,86
Software fuse tariff	0,3	868,8	44,74	915,4	-1,86

If a customer did not use nighttime tariff, they would have to pay 28,73 € more with general distribution tariff. The new presented tariffs will bring more saving for the customer. In table 6.2 is shown the network impacts caused by changing tariff for 116 of 2184 customers in the primary substation network. The initial tariff was nighttime tariff and the new was software fuse. The primary substation is situated in Salo.

Table 6.2. *Network impacts of tariff change*

	Nighttime (initial state)	Software fuse
Year's peak power of primary substation (kW)	4 282	4 263
Costs of loss energy in a primary substation (€)/a	2 693	2 689,4
Loss energy of secondary substation network (kWh)/a	294 584,7	273 361,8
Energy losses of secondary substations (kWh)/a	169 328	158 703
The reduction of secondary substations' peak power on average in the case network (%)		7,20
The average load rate of secondary substation transformers in the case network (%)	42,0	40,8
The average voltage of connection points (V)	225,9	226,2
Voltage in connection points under 207 V (of 2184 pieces)	42	28

With the nighttime tariff and with the old consumption profile the yearly revenue calculated with average consumption of 8 200 customers is 10 335 377 €. The differences between the revenues with nighttime tariff and other tariffs are shown in table 6.3. The calculations are done for 8 200 customers, because FSS has roughly 8 200 customers with nighttime tariff and 3×35 A main fuse connection point.

Table 6.3. *Reductions in revenues*

	Elasticity	Yearly revenue of 8 200 customers (€), new consumption profile	The reduction of revenues (-€)	The reduction in percentages
General distribution	x	10 662 389	-327 012	-3,07 %
Multiple time tariff	0,1	10 281 064	54 313	0,53 %
Multiple time tariff	0,2	10 144 149	191 228	1,89 %
Multiple time tariff	0,3	10 009 497	325 880	3,26 %
3 time energy & power tariff	0,1	10 047 969	287 408	2,86 %
3 time energy & power tariff	0,2	9 971 025	364 352	3,65 %
3 time energy & power tariff	0,3	9 623 646	711 731	7,40 %
RTP loss tariff	0,1	10 318 404	16 973	0,16 %
RTP loss tariff	0,2	10 272 012	63 366	0,62 %
RTP loss tariff	0,3	10 225 619	109 758	1,07 %
Software fuse tariff	0,1	10 175 832	159 545	1,57 %
Software fuse tariff	0,2	10 000 445	334 932	3,35 %
Software fuse tariff	0,3	9 830 716	504 662	5,13 %

It is not reasonable to give discount for customers unless the DSO will also gain some economical benefit. If 8 200 customers changed from nighttime tariff to multiple time tariff, the estimated saving would be roughly 410 000 € per year. It is estimated by multiplying the gained savings from network calculation results from the case network to correspond the effects of required amount of customers. The savings result from avoiding the change of some transformers to bigger size and from avoiding secondary substation network reinvestment, for example, because of too low voltage. A drawback is that the savings result in the long term, because network design and investments are done in long-term scale. The results were calculated as follows. The consumption profile was modified for 116 customers using elasticity model to correspond the consumption with multiple time tariff, and then the network calculation with PowerGrid program was performed. These customers had electricity heating and nighttime tariff in use. The inspected network is situated in Kisko primary substation in Salo. The overall amount of connection points in that area was 2184. The customers had previously nighttime tariff and their average yearly consumption was 17,8 MWh per year. The saving from losses would be around 30 € yearly per customer. Another factor that affects on the preciseness of the calculations is that the changes in a network area do not always cause similar results in some other network area, because network areas are not identical.

As in table 6.3, with three-time tariff and with 0,3 elasticity level the reduction in revenues would be 711 731 €. It is high because the three-time tariff is not dependent on fuse size, whereas in all other tariffs basic charge is based on fuse size. The fuse size is presumed to be 3×35 A, although in some connection points 3×25 A would be adequate. It means that the basic charge would be significantly lower. For example, in nighttime tariff the basic charge is 174 € lower in a year with 25 A fuse than with 35 A main fuse in FSS area. The basic charge that is based on their maximum power is good for customer, because there is not significant leap between different power levels and payment.

The tariff calculator was designed to choose the most affordable tariff to a customer. Input data is one year consumption data, main fuse size and how much the customer supposes that they can change their consumption behavior. The calculations are made for the same customer, which was used as calculation example in previous calculations in this chapter, so the original peak power was 13,86 kW (the highest hourly average power). The results are shown in table 6.4. The elasticity value was 0,3. The high payment in RTP loss tariff is explained by the fact that the example customer uses lot of energy in those times when the price of electricity is high in that tariff. It also shows that what would be their peak power if their consumption was changed with 0,3 elasticity. Spot tariff is added as a reference to show how much the customer would have had to pay from the used energy in 2009 if they had Elspot price without any extra fees.

Table 6.4. *The calculation results from tariff calculator*

Tariff type	Yearly payment (€)	Peak power (kW)
Nighttime	944,29	13,86
General distribution	942,25	14,44
3-time energy & power tariff	935,17	15,15
Multiple time	849,23	15,07
RTP loss	1023,62	15,25
Software fuse	863,78	10,90
Spot	866,04	14,55

6.3 Further research

The recommendation for further research is that at least three-time energy & power tariff, three-time power tariff, multiple time tariff and software fuse tariff should be inspected more profoundly. A possible tariff besides these presented tariffs could for example be a combination of three-time energy & power tariff and three-time power tariff. Then there would be power charge that is different in summer and wintertime, and also different level at daytime, evening and nighttime. In addition, energy based distribution charge is different at daytime and at nighttime.

Three power tariffs were presented. An annual power tariff is good otherwise, but the steering impact is not very good, because the power charge is calculated from the highest hourly average power in a year. Three-time energy & power tariff and three-time power tariff have similar steering impact. Three-time power tariff was not included to calculations in chapters 5.3 and 6, because the elasticity determination would have required price for every hour of the year. Tariff that contains only power fee is simple for the customer to understand it. Due to smart grids, basic charges will likely increase in proportion to energy based grid fee if power tariffs are not introduced for household customers too.

AMR meters also measure reactive power, so it could be possible to invoice reactive power usage also from household customers. However, there are several problematic issues in reactive power invoicing. Firstly, customers' knowledge of reactive power is commonly very low and most of household customer's loads are resistive. On the other hand, increasing amount of heat pumps will increase the reactive power consumption in Finnish households. Secondly, household customers do not have affordable means to compensate their reactive power level. On the other hand, if household customers were invoiced of reactive power, it could motivate appliance manufacturers to design their products to use less reactive power, since it could be their competitive advantage.

The RTP loss tariff was mainly an experiment of real-time pricing, which correlates the expenses caused by customers to the electricity network. Although the tariff correlates with the real expenses, its impact to motivate customers to use electricity on the right hours is not high, because in table 5.9 values 2 and 3 that describe peak power and loss reduction are notably smaller for RTP loss tariff than with other tariffs in simulation calculations. Previously real-time pricing has been ideated only from retailer's point of view, so RTP loss tariff is one of the only tariffs that have been done purely for DSO's interests. Problems of RTP loss tariff are that for customers it is quite difficult to understand and to follow the prices. In addition, it requires that the price of each hour will be set to AMR meters properly and home automation is required so that demand response is realized well.

Software fuse tariff has very good steering impact theoretically, as in table 5.9 column value 2 shows that software fuse tariff has a very positive effect on peak power reduction. In other words, software fuse tariff could make people change their consumption from on-peak hours to off-peak hours very effectively. Peak power reduction was almost 25 % in simulations and that is very notable result. Some other tariffs were better in reducing network losses, but column value 3 should not be reviewed unambiguously. For instance general distribution tariff (*yleissiirto*) seems to cause less network losses than nighttime tariff, but when bigger section of network is inspected, nighttime tariff reduces losses and daily peak power notably. Software fuse technology makes possible to create several tariff variations, but only one tariff model was presented in this thesis.

Customers will get the best benefit from the new tariffs if they purchase in-home display. Using the in-home display will give customers real-time feedback of their electricity consumption behavior and that helps them to reduce their electricity consumption to suitable level if they want to save money. Besides in-home displays, programmable communicating thermostats (PCTs) is new technology to help customers to consume electricity on cheaper hours. PCTs enable demand response also in homes where is direct electric heating. In addition, the technology is quite affordable. A weekly schedule can be programmed to the thermostats or an aggregator can control them. Home temperature can be adjusted through Internet or via home automation technology.

In conclusion, there is much potential for new tariffs. The effects depend very much on which level the elasticity is in reality. The next step would be to study the elasticity, in order to do that the tariffs have to be changed for considerable amount of customers. The tariff choice has to be grounded on customer's own choice. However, the DSO should give advice and support to choice and inform them about the benefits that the customer, environment and DSO will gain. One suggestion on how to increase customer participation is to give price insurance for one year or for shorter period, so that the customer would not have to pay more than with original tariff, but they will gain reduction if they change their consumption profile.

7 CONCLUSION

The potential to achieve demand response via network tariffs is presented in this thesis. The economical effects are also reviewed. The principles of tariff design, the drivers for tariff structure change and several new network tariffs that could enable demand response are presented in this thesis. In addition, the technical solutions and some appliances that make the new tariffs possible to implement are introduced.

Smart grids, increasing energy efficiency and the aging of network infrastructure will cause economical challenges for DSOs in future. To make sure that distribution business will stay profitable, regulation model has to ensure stable business environment, because electrical network business is very capital-intensive sector. For example, the payback period of investments is very long, so the allowed rate of return has to be reasonable. The regulation model should not only stress the interests of society and customers, but also the interests of DSOs so that the future network investments can be done. In Finland, EMV regulates the monopoly business of DSOs. The reason for monopoly business is that the construction and operating of parallel networks is not possible and economically reasonable.

Energy saving actions, energy efficiency and distributed generation will reduce the amount of distributed energy. Therefore, the revenue of DSOs will decrease with present tariff structure. The changing operational environment drives the development of tariff structures, because the present tariffs are not capable of keeping the required income level.

The target of demand response programs is to curtail or shift loads for short periods. The incentive is either to respond to high wholesale prices or to even out power fluctuations. The primary motivation of DR is to avoid peak prices and to even out consumption variation.

Energy efficiency means using less energy to provide the same or improved level of service to the consumer in an economically efficient way, in other words, energy efficiency does not reduce customer's comfort. Energy saving is often occurred through behavioral changes that are short-term, whereas energy efficiency actions are done by installing long-lasting technologies. Demand response is one solution how to increase energy efficiency, since DR reduces network losses economically. Moreover, it is easier for customers to change the timing of electricity consumption than deduce the total need.

Obstacles to DR are, for instance, the inelasticity of demand and low level of participation due to lack of knowledge. The potential of DR varies between different European countries, since the household consumption profiles vary significantly. AMR rollout timetable and potential of manageable industrial loads also vary in different European countries. Demand response has been researched and piloted very much in recent years, but the actual achievements have not been sufficient in Europe. The benefits of demand response are recognized widely, but the practical implementation has not yet been successful.

There are several benefits of demand response. Need for land utilization will diminish because of avoided or deferred line and generation unit investments. Air quality will improve because of efficient use of resources. For example, carbon dioxide emissions will be reduced, since the most polluting electricity generation techniques are generally used during the peak demand hours. Even a small reduction in power consumption will effect positively on climate pollution.

One major problem is the conflict between distribution system operator and retailer, because both may have different perspectives on demand response. Both have the same object, to maximize their business profit, but their ways to reach it is different. Retailer is interested in minimizing energy acquisition costs, by reducing consumption in high market price hours. Whereas the DSO's interest is to keep the consumption profile as even as possible by avoiding demand peaks. Conflicts may appear when the market price does not correlate with the loading level in the local distribution network. Moreover, because of unbundling, the DSOs possess the load control and AMR infrastructure. It makes more difficult for the retailers to introduce spot-priced products if the other party owns the load control infrastructure. Spot-pricing includes quite much risk for the customer, whereas the new network tariffs that are presented in this thesis contain only a small risk for the customer compared to spot-priced tariffs.

The new tariffs that are presented in this thesis were designed using both existing consumption profile of detached house with electric storage heating and actual meter reading data. The target of these new tariffs is to modify the consumption behavior so that the grid would be used as effectively as possible. The effective usage means using power as evenly as possible. The new tariffs are designed on the principle that the yearly payment would be a bit higher than with old tariff if the customer uses electricity as previously. On the other hand, if the customer changes their consumption to more affordable hours, their electricity bill's grid fee will become smaller. Several different tariffs were ideated and from those the ones that could have the best steering impact, and also the ones that are quite easy to understand, were chosen to further development. Their impact on distribution business and investment needs were also calculated.

The new tariffs that were created are annual power tariff, three-time power tariff, three-time energy & power tariff, multiple time tariff, RTP loss tariff and software fuse tariff. These tariffs are presented more profoundly in chapter 5.1. The reason why power tariffs were developed for household customers is that distributed generation will decrease the amount of distributed energy, but the need for the power distribution capacity will remain the same or increase.

Several positive impacts on the network were discovered in simulation calculations. In primary substation level the peak power of a year decreased and cost of loss energy reduced. In secondary substation level, the energy losses reduced too, the peak powers reduced in secondary substations and the load rate of transformers reduced. In addition, the number of connection points where the voltage was under allowed level was reduced in the simulations.

Most of the studies concerning demand response have been written from retailer's point of view and the objective has mainly been to increase price elasticity in demand. Price elasticity is a part of demand response, meaning that consumption responds to the price of electricity. It should be noticed too that not only retailers want to introduce demand response tariffs, but also DSOs are willing to introduce new tariffs that can enable demand response. Moreover, the implementation of the new introduced network tariffs will have no technical hindrances when AMR rollout will have concluded in a couple of years.

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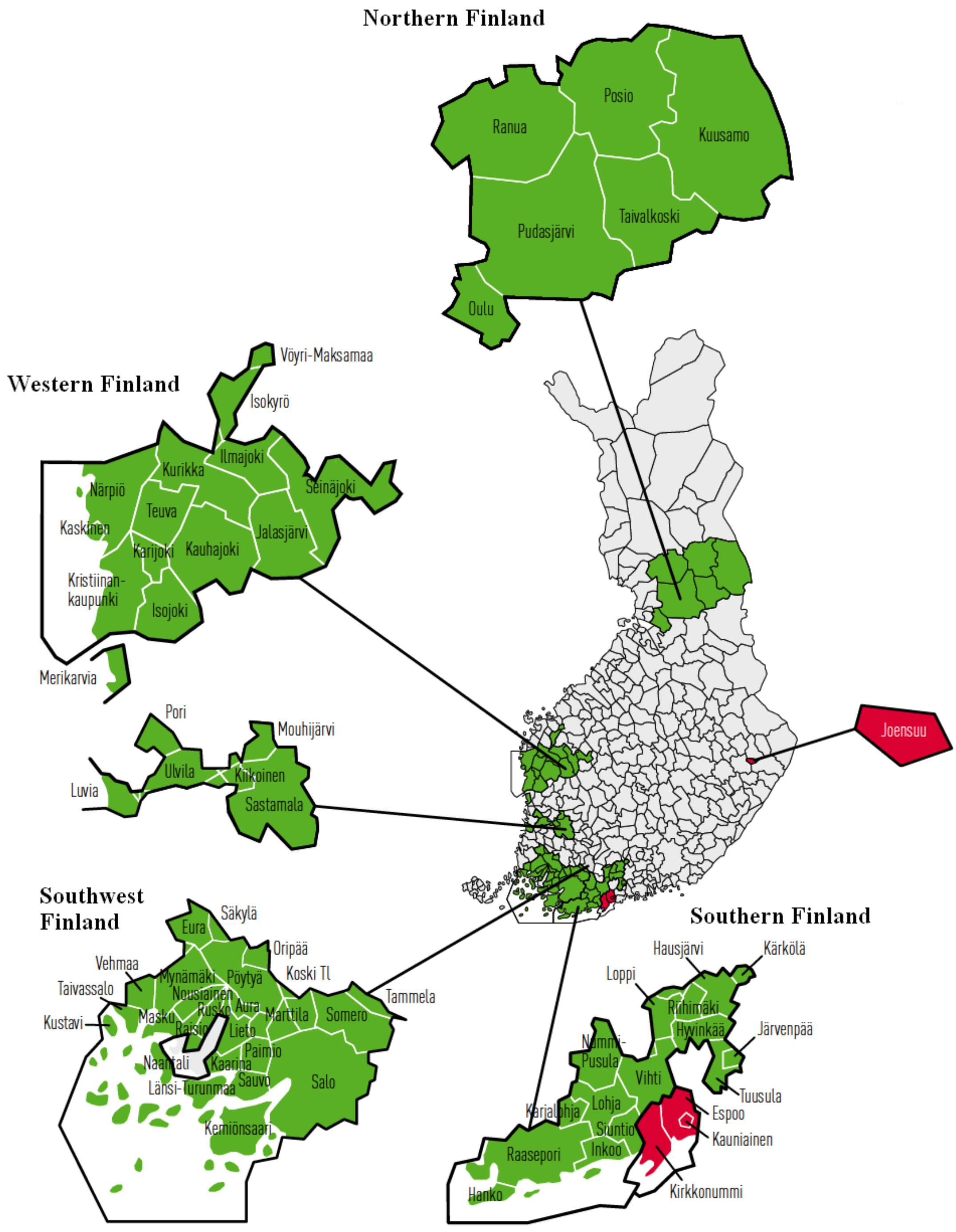
APPENDIX

APPENDIX 1 –THE DISTRIBUTION NETWORK REGIONS OF FORTUM IN FINLAND



Fortum Sähkönsiirto Oy
Fortum Espoo Distribution Oy
© Kuntarajat: Tilastokeskus

APPENDIX 2 – CURRENT NETWORK TARIFFS IN FED AREA

Sähkön siirtohinnasto

Tämän siirtohinnaston mukaisilla maksuilla verkkoyhtiö huolehtii sähköenergian siirtämisestä tuottajalta asiakkaalle ja tarjoaa siirtoon liittyvän verkkopalvelun: verkoston kunnossapidon, sähkönkulutuksen mittauksen ja ympärivuorokautisen vikapäivystyksen. Sähkön siirrossa noudatetaan asiakkaan kanssa tehtyä yksilöllistä verkkopalvelusopimusta, siihen liittyviä yleisiä verkkopalveluehtoja ja voimassaolevaa hinnastoa. Kaikki hinnat sisältävät arvonlisäveron (23 %), ellei muuta ole mainittu.

Siirtotuotteen valinta

Kun käyttöpaikan pääsulake (sulakepohja) on enintään 63 A, voit valita siirtotuotteistamme sen, joka parhaiten soveltuu tarpeisiisi. Valittavanasi on Fortum Yleis-, Yö-, Kausi- tai Tehosiirto. Voit vaihtaa tuotteen, kun olet käyttänyt sitä vähintään vuoden ajan. Sulakepohjan ollessa yli 63 A siirtotuotteena sovelletaan Fortum Tehosiirtoa (PJ tai KJ).

Sähkövero

Sähkölaskun yhteydessä laskutetaan hinnaston mukaisten hintojen lisäksi kulloinkin voimassa oleva sähkön kulutukseen perustuva sähkövero (energiavero ja huoltovarmuusmaksu). Kaikki asiakkaat kuuluvat automaattisesti veroluokkaan 1, elleivät ole muuta ilmoittaneet. Asiakas on oikeutettu veroluokkaan 2, jos käyttöpaikalla harjoitetaan sähkön valmisteverosta annetun lain mukaista teollisuutta tai ammattimaista kasvihuoneviljelyä. Jos asiakas on oikeutettu alempaan veroluokkaan 2, tulee siitä toimittaa kirjallinen vakuutus verkkoyhtiölle.

Veroluokka 1: 2,0947 c/kWh, sis. alv 23 %
Veroluokka 2: 0,8647 c/kWh, sis. alv 23 %

Fortum Yleissiirto

Perusmaksu €/kk	2,93
Siirto c/kWh	3,13

Fortum Yösiirto

Perusmaksu €/kk	7,55
Päiväsiirto c/kWh	3,32
Yösiirto c/kWh	1,92

Päiväsiirto: ma–la klo 7–21

Fortum Kausisiirto

Perusmaksu €/kk	7,55
Päiväsiirto, talvi c/kWh	4,20
Muun ajan siirto c/kWh	1,94

Päiväsiirto, talvi: ma–la 7–21 ajalla 1.11.–31.3.

Fortum Tilapäissiirto

Tilapäissiirto soveltuu väliaikaiseen sähkönkäyttöön, kun asiakkaan kanssa ei ole tehty liittymissopimusta. Siirtotuotteena on Fortum Yleissiirto. Perusmaksu veloitetaan kaksinkertaisena.

Fortum Tehosiirto

Fortum tehosiirtotuotteet on tarkoitettu paljon sähköä käyttäville asiakkaille. Keskijännitetehosiirrossa sähkön toimitus tapahtuu 20 kV:n keskijännitteellä. Tämä edellyttää, että asiakas itse omistaa muuntamonsa, vastaa sen käytöstä ja siihen liittyvistä asennuksista. Tehomaksun mittausjakso on yksi tunti. Maksu määräytyy kuukausittaisen huipputehon mukaan. Loistehomaksun perusteena on kuukausittainen loistehohuippu, josta on vähennetty 20 % saman kuukauden pätötehohuipun määrästä.

Fortum Tehosiirto PJ (0,4 kV toimitus)

	alv 0 %
Perusmaksu €/kk	31,50
Tehomaksu €/kW, kk	1,55
Loistehomaksu €/kVAr, kk	3,12
Päiväsiirto, talvi c/kWh	2,30
Muun ajan siirto c/kWh	1,12

Päiväsiirto, talvi: ma–la klo 7–22 ajalla 1.11.–31.3.

Fortum Tehosiirto KJ (20 kV toimitus)

	alv 0 %
Perusmaksu €/kk	141,50
Tehomaksu €/kW, kk	1,19
Loistehomaksu €/kVAr, kk	3,12
Päiväsiirto, talvi c/kWh	1,63
Muun ajan siirto c/kWh	0,79

Päiväsiirto, talvi: ma–la klo 7–22 ajalla 1.11.–31.3.

APPENDIX 3 – CURRENT NETWORK TARIFFS IN FSS AREA

Sähkön siirtohinnasto

Tämän siirtohinnaston mukaisilla maksuilla verkkoyhtiö huolehtii sähköenergian siirtämisestä tuottajalta asiakkaalle ja tarjoaa siirtoon liittyvän verkkopalvelun: verkoston kunnossapidon, sähkönkulutuksen mittauksen ja ympärivuorokautisen vikapäivystyksen. Sähkön siirrossa noudatetaan asiakkaan kanssa tehtyä yksilöllistä verkkopalvelusopimusta, siihen liittyviä yleisiä verkkopalveluehtoja ja voimassaolevaa hinnastoa. Kaikki hinnat sisältävät arvonlisäveron (23 %), ellei muuta ole mainittu.

Siirtotuotteen valinta

Voit valita sähkön siirtotuotteistamme sen, joka parhaiten soveltuu tarpeisiisi. Tuotteen voit vaihtaa, kun olet käyttänyt sitä vähintään vuoden ajan. Kuitenkin kesäkautena 1.4.–31.10. Fortum Yleis-, Yö- ja Kausisiirrossa pääsulaketta voi suurentaa (yksi edestakainen vaihtokerta/kausi) lunastetun liittymäkoon puitteissa. Sulakemuutoskäynneistä peritään palveluhinnaston mukaiset maksut. Kesäkautena pääsulakekoko tulee olla vähintään yhtä suuri kuin talvikautena.

Sähkövero

Sähkölaskun yhteydessä laskutetaan hinnaston mukaisten hintojen lisäksi kulloinkin voimassa oleva sähkön kulutukseen perustuva sähkövero (energiavero ja huoltovarmuusmaksu). Kaikki asiakkaat kuuluvat automaattisesti veroluokkaan 1, elleivät ole muuta ilmoittaneet. Asiakas on oikeutettu veroluokkaan 2, jos käyttöpaikalla harjoitetaan sähkön valmisteverosta annetun lain mukaista teollisuutta tai ammattimaista kasvihuoneviljelyä. Jos asiakas on oikeutettu alempaan veroluokkaan 2, tulee siitä toimittaa kirjallinen vakuutus verkkoyhtiölle.

Veroluokka 1: 2,0947 c/kWh, sis. alv 23 %
Veroluokka 2: 0,8647 c/kWh, sis. alv 23 %

Fortum Yleissiirto

Siirto c/kWh	**2,79**
Lisäksi perusmaksu pääsulakkeen (sulakepohjan) mukaan:	**€/kk**
Kerros- ja rivitalo, enintään 25 A	7,26
16 A ja 1-vaihe	10,89
25 A	14,52
35 A	25,51
50 A	44,06
63 A	68,56
80 A	103,34
100 A	125,52
125 A	150,73
160 A	188,03
200 A	229,36
250 A	282,80

Fortum Yösiirto

Päiväsiirto c/kWh	**2,79**
Yösiirto c/kWh	**1,82**

Lisäksi perusmaksu pääsulakkeen (sulakepohjan) mukaan:	**€/kk**
Kerros- ja rivitalo, enintään 25 A	9,68
16 A ja 1-vaihe	13,31
25 A	16,94
35 A	31,56
50 A	55,05
63 A	85,70
80 A	124,51
100 A	149,72
125 A	180,97
160 A	226,34
200 A	277,76
250 A	343,29

Päiväsiirto: ma–su, yleensä klo 7–22. *

Fortum Kausisiirto

Päiväsiirto, talvi c/kWh	**3,41**
Muun ajan siirto c/kWh	**1,76**

Lisäksi perusmaksu pääsulakkeen mukaan kuten Fortum yösiirrossa.
Päiväsiirto, talvi: ma–su, yleensä klo 7–22 ajalla 1.11.–31.3.

Fortum Tilapäissiirto

Fortum Tilapäissiirto soveltuu väliaikaiseen sähkönkäyttöön, kun asiakkaan kanssa ei ole tehty liittymissopimusta. Siirtotuotteena on Fortum Yleissiirto. Perusmaksu veloitetaan kaksinkertaisena.

Fortum Tehosiirto

Fortum Tehosiirto -tuotteet on tarkoitettu paljon sähköä käyttäville asiakkaille. Keskijännitetehosiirrossa sähkön toimitus tapahtuu 20 kV:n keskijännitteellä. Tämä edellyttää, että asiakas itse omistaa muuntamonsa, vastaa sen käytöstä ja siihen liittyvistä asennuksista. Tehomaksun mittausjakso on yksi tunti. Tehomaksussa laskutustehona käytetään viiden viimeisen talvikuukauden (1.11.–31.3. klo 07.00–22.00) aikana mitatun kahden suurimman kuukausitehon keskiarvoa. Tehomaksua veloitetaan pienjännitteellä vähintään 60 kW ja keskijännitteellä 200 kW tehon mukaan. Loistehomaksun perusteena on kuukausittainen loistehohuippu, josta on vähennetty 20 % saman kuukauden pätötehohuipun määrästä.

Fortum Tehosiirto 1 PJ (0,4 kV toimitus)

	alv 0 %
Perusmaksu €/kk	41,50
Tehomaksu €/kW, kk	1,66
Loistehomaksu €/kVAr, kk	4,22
Siirto c/kWh	1,93

Fortum Tehosiirto 2 PJ (0,4 kV toimitus)

	alv 0 %
Perusmaksu €/kk	41,50
Tehomaksu €/kW, kk	2,52
Loistehomaksu €/kVAr, kk	4,22
Päiväsiirto, talvi c/kWh	1,92
Muun ajan siirto c/kWh	1,26

Päiväsiirto, talvi: ma-su, klo 7-22 ajalla 1.11.-31.3.

Fortum Tehosiirto 1 KJ (20 kV toimitus)

	alv 0 %
Perusmaksu €/kk	41,50
Tehomaksu €/kW, kk	1,44
Loistehomaksu €/kVAr, kk	4,22
Päiväsiirto, talvi c/kWh	1,88
Päiväsiirto, kesä c/kWh	1,42
Yösiirto c/kWh	1,12

Päiväsiirto: ma–su, klo 7–22. Talvikausi: 1.11.–31.3.

Fortum Tehosiirto 2 KJ (20 kV toimitus)

	alv 0 %
Perusmaksu €/kk	2491,50
Tehomaksu €/kW, kk	1,44
Loistehomaksu €/kVAr, kk	4,22
Päiväsiirto, talvi c/kWh	0,84
Yösiirto, talvi c/kWh	0,78
Päiväsiirto, kesä c/kWh	0,59
Yösiirto, kesä c/kWh	0,56

Päiväsiirto: ma–su, klo 7–22. Talvikausi: 1.11.–31.3.

APPENDIX 4 – DEMAND RESPONSE PROGRAMS IN USA

State	Time-Based	Direct Load Control	Other Incentive-Based	Emergency Demand Response	Interruptible Load	Other	State Total
AK							0
AL	11	10			1,148	62	1,231
AR	206	198			1,269		1,673
AZ		30			144	-	174
CA	534	785	593	425	457	1	2,795
CO	104	176			191		471
CT			5	752			757
DC			44	40			84
DE			160	128			288
FL	90	2,586	38	25	429	56	3,224
GA	559	230	1		293	-	1,083
HI		20			29		49
IA	5	315	512	23	311		1,166
ID	0	343	0				343
IL	7	60	1,160	1,353	39	-	2,619
IN	46	86	1,304	372	83		1,891
KS	9	26	1	34	125	3	198
KY	67	147	28	1	2		245
LA	1	0			535		536
MA	0		61	601			662
MD	70	14	752	817	11		1,664
ME			1	483			484
MI	3	264	934	44	503		1,748
MN	563	1,453	1,139	229	891	135	4,410
MO	122	73	-	5	217	1	418
MS	100				119		219
MT		0					0
NC	198	317	40	111	1,210	46	1,922
ND	31	22	37	1	68	1	160
NE	2	324		135	170	1,000	1,631
NH		9	7	90			106
NJ	0	2	247	525	8		782
NM	14	58			4	-	76
NV	78	143			40		261
NY	53	42	2,618	972	249		3,934
OH	5	52	610	1,137	287		2,091
OK	823	12	4	420	213		1,472
OR		20					20
PA	18	29	988	1,760	266		3,061
RI			15	110			125
SC	238	43			800	21	1,102
SD	13	418	63	3	55		552
TN			37	15			52
TX	25	135	1,074	1,138	202	5	2,579
UT		113					113
VA	14	144	418	623	18	10	1,227
VT	45	5	3	83	24		160
WA	37	6				-	43
WI	178	288	1,265	98	527	0	2,356
WV			270	487			757
WY	0	8			41		49

Reported potential peak load reduction in megawatts by program category and state (Wight et al. 2011)