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Network tariff structures in Smart Grid environment

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Summary

This report examines the emerging options and requirements for electricity transmission and distribution network tariffs in the evolving Smart Grid (SG) environment. Smart Grids mean more sophisticated metering and communication technologies, which enhance possibilities to make tariffs more transparent, more economically efficient and cost-reflective, and more just. Automatic meter reading including hourly measurements is one of the most obvious enabling technologies of new tariff structures.

A review of desirable tariff properties from the economic theory point of view is conducted. According to it, marginal cost based pricing maximises the social welfare also in networks, despite them being considered natural monopolies. The "first best optimum" of any distribution or transmission company, from the social welfare point of view, is setting the price (tariff) equal to the marginal costs. However, marginal cost principle cannot be directly applied in pricing and tariff design of network activities; if prices are equal to marginal costs, revenues of a producer fall short of total costs implicating financial losses. In the light of economic theory, attractive methods to ensure cost recovery *(Ramsey pricing* and *optimal two-part tariffs)* and to determine marginal costs of electricity taking the network properties into account, i.e. *locational marginal pricing*, are reviewed.

The implementation of tariff schemes may be restricted by the fact that there are several companies and organizations involved in electricity supply chain. With both regulated and deregulated actors present, the set-up is also not straightforward from economic theory point of view. Thus, trade-offs between tariff design objectives (*sustainability, economic efficiency, non-discrimination or fairness, additivity, and transparency*) seem practically unavoidable. So called *rolled-in pricing methods* are currently widely used. Their drawback is their limited incentives in steering market participants towards economic efficiency.

The problem of integrating intermittent and non-dispatchable electricity production from renewable energy sources into the power system is estimated to become significant in the future. Demand response, energy storages and other distributed energy resources are part of the potential solution and present a possibility and a wish for the end-user to take a more active role in electricity markets. Together with SG developments, they bring new options and needs for design and price setting of network tariffs. This justifies more dynamic, real-time varying components, cost-causality and incentives in pricing and tariffs.

Tests were carried out in KOPTI test bed in order to simulate the behaviour of an electric heating end-user with or without a heat storage under different types (one price, real-rime pricing and time-of-use) of sales and distribution tariffs. The savings for the end-user from load-shifting by the optimal use of the heat storage were quite modest; even a winter week having very high price peaks resulted in savings under ten percent at best. Without ToU distribution tariffs, load-shifting will benefit end-users having RTP sales tariffs just 16 cents in the running costs in a normal winter week, if the heat storage losses are 1% per hour. Potential long-term system benefits from activeness of end-user, such as avoiding investments in costly capacities, were not estimated.

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Preface

The study is part of the Smart Grid and Energy Market (SGEM) research programme, which in turn is part of the Finnish research cluster Cleen Oy. The report describes the results from task 5.1.2 in SGEM 1 funding period work package "Business logics of TSOs and DSOs" (SGEM 1FP WP5.1). The first funding period started in 2009 and ended 28.2.2011.

The aim of this task is to analyze and determine the potential new structures for network tariffs in Smart Grid environment. The change in use of electricity, elasticity of demand, mobile loads, large penetration of DG and energy storages will change the business logic of DSOs and TSOs and new structures for charging the customers and producers are needed. Other related issues, energy tariffs, the electricity market, distributed energy resources etc. are studied in other work package tasks and in other SGEM work packages.

SGEM 1FP WP5.1 had a common steering group with WP5.2 and WP5.3, the members of which were Ville Karttunen and Kari Koivuranta, Fortum, Sauli Antila, Vattenfall, Seppo Hänninen, VTT, Samuli Honkapuro, LUT, Merja Pakkanen, Vaasan yliopisto, and Pertti Järventausta, TUT.

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Authors

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Abbreviations and acronyms

AMR	Automatic Meter Reading
CfD	Contract for Differences
CHP	Combined Heat and Power
CPP	Critical Peak Pricing
CPR	Critical Peak Rebate
DER	Distributed Energy Resources (DG, Energy storages, DR)
DG	Distributed Generation (capacity connected to the distribution network, as opposing to central power production)
DLC	Direct Load Control
DR	Demand Response
DSI	Demand Side Integration
DSM	Demand Side Management
DSO	Distribution System Operator
EV	Electric Vehicle
FDC	Fully Distributed Costs
KOPTI	VTT's Optimisation model (KokonaisOPTImointimalli)
LMP	Locational Marginal Pricing
LRMC	Long Run Marginal Cost
MW	MegaWatt = 1,000,000 W
PTR	Peak Time Rebate
RES	Renewable Energy Resources
RES-E	Electricity production from RES
RTP	Real-Time Pricing
SG	Smart Grid(s)
SGEM	Smart Grid and Energy Market research programme, part of Cleen Oy
SRMC	Short Run Marginal Cost
TSO	Transmission System Operator
ToU	Time of Use (tariff structure)
TWh	TeraWattHour = 1,000,000 MW -hours
V2G	Vehicle-to-grid
VAT	Value Added Tax
VTT EMM	VTT's Electricity Market Model

1 Introduction

There has been a trend towards more liberalized electricity markets throughout the world since the late 1980's. Many power systems are not only deregulated, but they are also going through a strongly promoted increase in the share of renewable energies and decentralized production. Although wind power and photovoltaic, as intermittent production forms, are laying high demands on the power system, new or improved network and load control possibilities might offer cost-efficient solutions for power system control and management.

Components of the supply chain of electricity to end customers include *generation*, *transmission*, *distribution*, and *supply (retail)*. Moreover, smaller sub-parts of these components can be seen, consisting of *metering* and *billing*, *customer accounting*, *customer service* etc. In a typical model of liberalization, generation and supply (retail) are considered potentially competitive businesses, whereas transmission and distribution are considered natural monopolies.

In a typical "textbook-model" of liberalized electricity markets, transmission and distribution (activities related to electricity network) as natural monopolies are *regulated* businesses. This indicates their pricing is not completely freely set by network companies but under a regulation scheme carried out by public authorities. Regulation includes various details; however, simply put, a regulator uses a chosen method to analyze if profits or revenues for network companies are reasonable considering the risk related to this type of business.

Generally, tariff design refers to a process where costs of especially regulated businesses are determined and allocated to customers according to a chosen procedure. Although the basic idea is simple, a closer look reveals that design of transmission and distribution tariffs (generally network tariffs) includes a wide variety of options. These options in tariff setting include, among others,

- **Time resolution**: What is the basic time period used as basis for billing? Hour, day, week, month or a combination of these? Is the estimation of network costs to be covered by tariffs made and updated annually, monthly or more often?
- **Division of tariff between fixed and varying parts**. How much and how does the tariff depend on the volume of the energy used? Does the tariff include a component depending on peak load?
- **Tariff differentiation between customer types or companies**: do the tariffs differ e.g. according to distribution area (rural/urban), voltage level or annual energy/fuse size?
- **The cost basis of tariffs**: how do the tariffs address e.g. future investments of networks?
- **Regulation model**: is the feasibility of pricing reviewed by the regulator before or after the electricity delivery and how?

Smart Grid (SG), a term used for a 21st century electricity network utilizing modern information technology - currently under research and development - will potentially bring new options and needs for design and setting of network tariffs (see e.g. EC (2010) for description of the Smart Grid concept). The change brought by the new environment of SG concerns the use of electricity, elasticity of demand, mobile loads, large penetration of DG and energy storages etc. As the business logic of DSOs and TSOs is changed by SG, new structures for charging the customers and producers may be justified and emerge.

This report examines *the emerging options and requirements for transmission and distribution tariffs in the evolving environment of SG*. It presents an effort to shed light on these issues on the basis of a literature review. On the other hand, a theoretical approach is insufficient on its own. It needs a practical counterpart, which is why the layout of a tariff test bed is analysed and a test bed set up.

The structure and contents of the report is as follows:

- Chapter 2 provides with a theoretical framework to principles of pricing of transmission and distribution of electricity. That is, the questions of appropriate and theoretically optimal tariffs are approached based on economic theory.
- Chapter 3 deals with the practical approaches taken and options available in electricity network tariff design. Problems encountered especially in applying economics in electricity systems environment, are under interest. A classification of practical design options and a review of tariff structures used in Europe are presented.
- Chapter 4 seeks new applications enabled by Smart Grids that could enhance the possibilities of theoretical ideas of tariff structures into reality. Advanced real-time metering presents an example of emerging options. Furthermore, a brief review of future trends in electricity systems is taken, since they affect the potential and needs for new tariff options.
- Chapter 5 presents the results of modelling studies conducted in the project. These deal with the monetary effects of emerging options for tariff structures by SG. Particularly, a prototype test bed is introduced and used for testing the dynamic behaviour of end-users.
- Chapter 6 concludes the study.

2 Transmission and distribution of electricity - pricing principles from economic theory

In this Chapter, classical economic theory is briefly reviewed as a background for studying network tariff design options. In a context of liberalization of electricity markets, theoretical justification from economics aims at higher degree of efficiency through introducing competition; typically this applies to generation and retail. However, discussion of pricing and tariff structures of transmission and distribution calls for taking a look at the electricity system and markets as a whole. Thus, both regulated and competitive activities are covered.

2.1 Relevant economic theory - basic concepts

In general economic theory of markets, equilibrium of supply and demand of products determines market price and the produced amounts of products. A key result is that equilibrium prices reflecting **marginal cost** of production maximise the summed surpluses of consumers and producers.

Marginal cost is the change in total cost that arises when the quantity produced changes by one unit. Marginal costs include all costs which vary with the volume of production, and other costs are considered **fixed costs**. Marginal costs are related to timeframe of economic decision - in the long-run, all costs are marginal costs.

The term short-run marginal cost is used when assuming that the capacity is fixed. In the long-run, it is also possible to make investments in capacity and, correspondingly, the term long-run marginal cost is used. Long-run marginal cost reflects the cost of adding the production by one unit. If short-term and long-term marginal costs are equal, the installed capacity is sufficient to meet the markets demand. If capacity is not sufficient, market price rises to a level where long-run marginal costs are exceeded, signaling new capacity to enter into market. Thus, in the long-term optimal solution, capacity should be built to a level where the prices cover the long-term marginal costs.

In competitive markets, the favourability of marginal cost as an efficient price signal is based on the assumption of markets being perfect under perfect competition. This can be formulated e.g. as by Krause (2003):

1. Consumers as well as producers are price takers
2. Perfect information
3. Free entry and exit to the market
4. A homogenous product is produced

In practice, all markets contain imperfections. In this report, the concept of a theoretical perfect market is used as an illustrative description for analysis of tariff structures. Taxes, subsidies and regulatory instruments may be used by public authorities to steer the output of markets. They can be used to improve their outcome from welfare distribution point of view or to address externalities, such as environmental effects of production.

However, referring to the perfect market does not always mean that it is - or should be - the target state for all real-world markets. Basics of economics from a viewpoint of electricity networks (transmission) are clearly and appropriately presented e.g. in Krause (2003) and are not more thoroughly discussed here.

2.2 Theoretical basics of distribution and transmission pricing

The objective of the pricing system can be described as a way to communicate information regarding the cost of each activity. In electricity supply, there exist several actors and activities in the delivery chain.

According to theory of efficient pricing, consumers should face prices equal to marginal cost of electricity service in order to make economically efficient energy-related decisions (e.g. Parmesano 2007) in order to maximise social welfare (a sum of benefits of producers and consumers).

The above principles on desirable pricing work as a guideline to the following subsections. First, the relevant actors and physical infrastructure of electricity delivery are described and second, it is discussed how the general pricing guidelines from economics fits in this environment.

2.2.1 Actors and functioning of electricity systems and networks

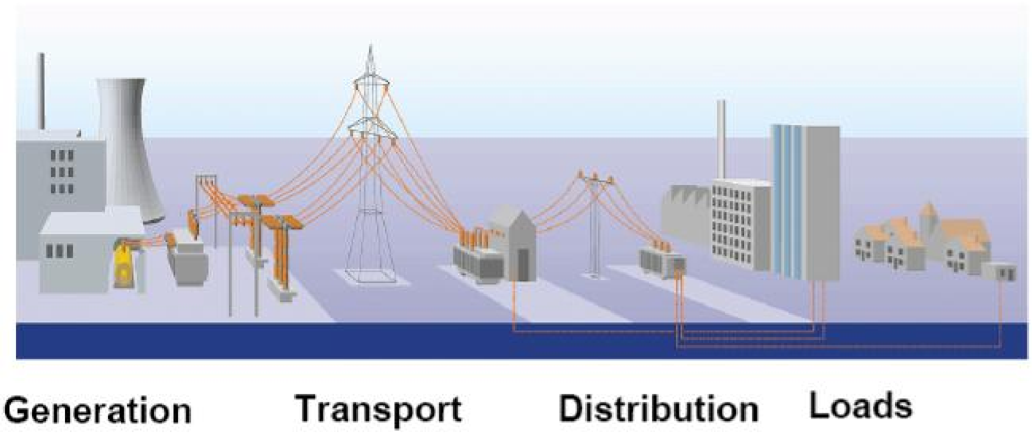

Fig 1. The electric power system. (Streit 2006)

When analysing network tariffs, the properties of whole system must be considered. This is due to the interdependencies between the components of electricity delivery (Fig 1). Participants involved in these phases include distribution companies, (national) transmission company, regulator, generation companies, end-use customers and sales companies. The following description of participants, mainly describing the Finnish/Nordic approach, is borrowed and edited from Evens (2011).

In generation, there exist several technologies (nuclear, hydro power, wind power, combustion technologies such as Combined Heat and Power (CHP) plants, just to mention some categories) to convert primary energy sources to electricity. The economically most efficient scale differs between these technologies, depending on the cost structure of the power plants.

The generation companies (generators) can sell the produced power either on the power exchange or directly to retailers. Generators are also often retailers themselves. Physically, the electricity is most often delivered to the transmission network. In the case of small production units, such as wind mills, solar panels or small CHP installations, the delivery is made to the distribution network.

The Transmission System Operator (TSO) is responsible for making physically possible the transport of power from the producers to the consumers at the high voltage (110kV, 220kV and 400kV in Finland) level. Large production units, as well as some very large consumers (large industries), are connected directly to the transmission network. Small production units and most consumers are connected to the medium or low voltage network, which itself is connected to the transmission network.

The TSO role involves several activities. The first is to partake in organising and maintaining the power exchange (see the paragraph about power exchange below). The second is to keep the system balanced (see the chapter balancing responsible party below). Other activities include the maintenance of the voltage level (by controlling the reactive power production and consumption), the maintenance and upgrading of the transmission power lines, the allocation of capacity on the interconnections with the neighbouring transmission systems and the deliverance of certificates (e.g. guarantee of origin certificates for renewable energy sources in Finland).

The role of the Distribution System Operator (DSO) is to operate the distribution (medium to low voltage) network(s). It should "guarantee access to the network for all users, applying objective, transparent, and non-discriminatory standards" (Fingrid 2011).

The power exchange is a platform on which electricity can be sold or bought. Electricity can also be traded by the actors directly among each other without going through the power exchange. On the day-ahead basis, the participants send offers before noon for consumption or production for the following day. The power exchange aggregates those bids to form supply and demand curves and sets the market price accordingly. The objective of a power exchange is to allow and encourage fair, transparent and cost reflecting prices. Thus the organization of such a market should be handled by a regulated actor.

There are different types of **consumers** with different needs and different behaviours. Consumers with higher energy consumption would tend to be ready to invest more in energy efficiency and in demand response capabilities. Some large industries already offer demand response services to the TSO.

Consumers have relationships with a DSO and with a retailer. The DSO is set and related to the location, but the retailer can be chosen among all the retailers active in the area (the whole Finland for example is a single retailing area). The billing should make the distinction between retail and distribution clear.

2.2.2 Economic characteristics of transmission and distribution

In liberalized electricity market, distribution and transmission of electricity are typically considered **natural monopoly** activities. The ratio of fixed to variable costs of supply is high in natural monopolies. This might be e.g due to the fact that building and maintaining infrastructure is costly in comparison to increasing the production by one unit.

Increasing returns to scale are a typical feature of natural monopolies. Thus, there is no economic justification to introduce competition by opening up a natural monopoly industry to a competition between two or more actors. In this case, the benefits of returns to scale are considered bigger than potential efficiency gains by competition. The activity of transmission is typically run by public (national) transmission grid operator and distribution by (potentially private) local distributions companies. This calls for efficient regulation of pricing.

Lumpiness of capacity is another typical feature of distribution and transmission (Rious 2008). "Lumpiness of capacity means that one unit change in output may result little or no change in cost most of the time, but the same change will result in a very large jump in cost if it requires the installation of an expensive new lump of capacity" (Park 1989).

Transmission and distribution are exceptionally heterogeneous products. They can be both a substitutes and complements to generation. Furthermore, both positive and negative externalities are related to transmission (Stoft 2006) and distribution. Also these factors may be significant from economic theory point of view and taking them into account may impose requirements on tariff design.

2.2.3 Implications on pricing from theory

Within electricity markets, marginal costs are often discussed in a context of potentially competitive generation and retail activities. Within these activities, efficiency is aimed through competition and assumption of competitive markets, implicating the market equilibrium is reached at marginal costs.

Transmission and distribution activities and taxes can add up to over a half of total cost of electricity service (Viljainen 2005). Thus, network activities can significantly affect the total efficiency of pricing. Even though generation could theoretically be assumed to be priced efficiently in (competitive) wholesale markets, a question 'can we conclude that the retail price is also efficient?' can be raised, as is done by Kopsakangas-Savolainen (2002).

A key result from network activities point of view is that the argument for marginal cost based pricing maximises the social welfare has theoretical justification also in natural monopoly activities (Kopsakangas-Savolainen 2002). That is, the "first best optimum" of any company, from the social welfare point of view, can be said to be setting the price equal to the marginal costs. However, there are practical issues that cause this principle to not be directly applicable. These issues are discussed in the following.

In natural monopolies, the long-run average cost decreases as a function of production. Due to substantial fixed costs, a decreasing average cost function is typical in electricity network business. Thus, if prices are equal to marginal costs, revenues of a producer fall short of total costs implicating financial losses. Thus, marginal cost pricing applied in distribution or transmission would often implicate negative profits.

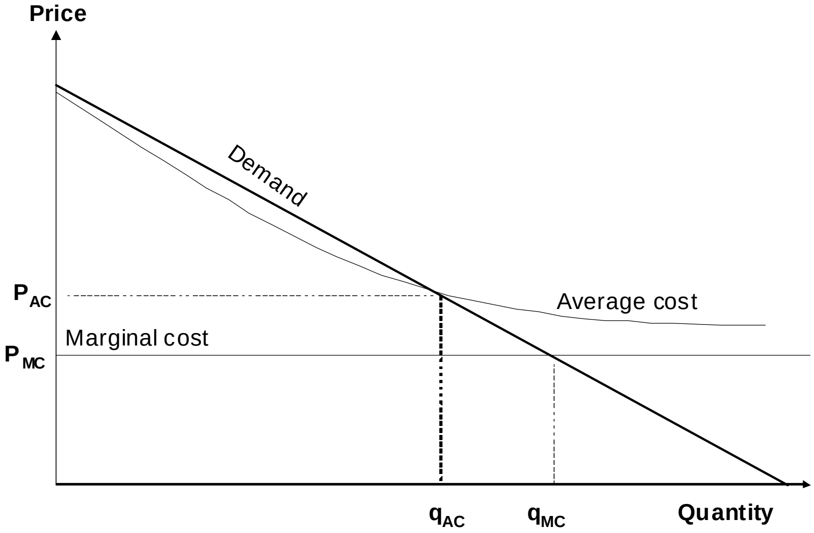

Fig 2. The cost structure of natural monopoly: average cost declines as production quantity increases.

The case of decreasing average costs is illustrated in the theoretical example of *Fig 2*. It is seen that pricing at marginal cost (point $P_{MC,}\, q_{MC}$) causes a loss equal to an area restricted by a gap between marginal costs and average cost and the corresponding quantities (q_{MC} -q_{AC}). Thus, costs and revenues of a producer do not break even[1].

Also regulated network companies are usually expected to cover their costs. This implicates a need for alternative approaches to marginal cost pricing. A straightforward alternative would be to consider average costs as pricing method. Average cost based pricing is also widely used. Its disadvantage is economic inefficiency potentially implicating welfare losses.

There are two special features in electricity transport that have implications for determining the economically efficient price. First, **congestion** of electricity networks refers to a situation where the capacity of transport lines limits electricity transport that would be economically justified on the basis of generation cost. Second, **losses** that occur in electricity transport have to be considered. Whenever electricity is transported, a fraction of it is lost. Efficient pricing taking into account congestion and losses is a widely discussed issue, and suggested solutions are discussed in section 2.3.2.

[1] Please note that an unregulated monopoly would not price the product optimally from the society's point of view if it is to maximise its profits. Thus, it would be a regulator's task to guarantee optimal pricing.

2.3 Approaches to address the pricing implications from theory

2.3.1 Pricing of natural monopolies

If marginal cost principle is applied, budget subsidies are one possible source to finance the costs not covered by marginal costs (residual costs) of generators. However, derived from theory, there are several methods to determine the tariffs so that the break-even of costs and revenues are reached. Kopsakangas-Savolainen (2002) discusses three theoretical alternatives: *Ramsey pricing*, *optimal two-part tariff* and *FDC pricing* (Fully Distributed Costs method).

- **Ramsey pricing:** the prices and quantities are determined to a level which maximises the total surplus of producers and consumers *subject to the breakeven constraint* (second-best prices). Ramsey pricing implicates high mark-ups in the markets that are least influenced by disturbances of prices, and low mark-ups in the markets that are more easily disturbed. Thus, the mark-ups will be inversely proportionally to elasticity of demand in the solution.
- **Optimal two-part tariffs:** A two-part tariff structure consists of a usage charge and a fixed entry fee. The target of optimal two-part tariffs is to maximise the total surplus over all economic agents. A solution where usage charge is equal to the regulated firm’s marginal cost and the fixed entry fee at a level sufficient to cover the firm’s total costs, when it is paid by each consumer, is obtained. Optimal two-part tariffs result in highest possible welfare under certain assumptions. That is, it is required that none of the consumers will drop out of the market as a result of change in tariff structure (including e.g. mandatory fixed fees).
- **Fully Distributed Costs** method. The objective of FDC pricing is to allocate common costs according to a chosen criterion and then set prices so that each service just covers it’s fully distributed costs. Hence, the FDC may include costs not directly associated with a particular product or service. Typical of FDC pricing, the allocation of common costs is done without considering economically relevant criteria.
- Alternative methods to allocate the common costs of electricity networks include at least **theory of cooperative games**, and the **axiomatic approach to cost allocation** (Kopsakangas-Savolainen 2002). **Deep connection charges** are mentioned by Brunekreeft et al. (2005) as a possible complementary charge.

Kopsakangas-Savolainen (2002) applies Ramsey pricing, optimal two-part tariffs and FDC method empirically to Finnish distribution system. This is done in order to define efficient prices based on economic theory and to calculate the potential welfare improvements that can be achieved through these prices. As a result of the study, it is estimated that social welfare gains may be achieved if more efficient pricing principles are introduced. The resulting welfare is highest if first best prices based on marginal costs or optimal two-part tariffs are used. However, it is concluded in the study that there might be political difficulties to implement this kind of reforms in practice, especially when the impacts of pricing changes on actors in the electricity sector are substantial.

2.3.2 Locational marginal pricing

When congestion and losses of electricity network are accounted for, pricing based only on marginal costs of **generation** does not necessarily result in socially optimal allocation of generation.

Locational marginal pricing (LMP) or nodal pricing, the theoretical solution for market-based marginal pricing in this respect was theoretically introduced, according to Lévêque (2003), as late as in 1988 (Schweppe 1988). LMP is referred to as “theoretically ideal” for a basis of pricing system since it captures the above-mentioned externalities of electricity transport. Locational marginal pricing is sometimes referred to as “benchmark” for optimal short-run pricing of the use of the network (e.g. Brunekreeft et al. 2005).

Nodal prices are determined for predefined locations of the network, and they take into account the “difficulties” to transport energy in the network. For example, in Russian electricity markets, there are thousand of these locations (nodes), to which the potentially differing locational marginal prices are determined for every hour of the year.

It is important to notice that despite that the differences between LMPs reflect the value of short-term usage of network, the nodal prices are dependent on generation prices. That is, if there are significant differences in costs of generation between areas of the network, the more valuable the ability to transport electricity between these areas becomes. The corresponding values can be mathematically and computationally determined for complex electricity systems. Thus, LMP provides theoretically attractive options to be utilized in determining network costs, accurately capturing the properties of the physical electricity system.

In the long-run, the difference between LMPs would reflect the marginal network expansion costs. If the revenue from LMPs would cover the long-term costs of the network, investment signals set and resulting investments would be optimal. However, for various reasons, LMPs cover for only a 20-30% of costs of well-designed transmission networks (Brunekreeft et al. 2005). Thus, even though providing short-term signals for efficient operation, application of nodal pricing seems not to remove a need for additional transmission network tariffs in practice. As such, e.g. due to their inability to cover the fixed costs of networks, differences in LMPs are not adequate for transmission tariffs. Instead, they provide short-term price signals for generators and loads, signalling congestion and losses in grids

Nodal pricing provides an economically efficient market-based pricing mechanism for **short term operation of transmission systems**. The nodal pricing method - or close variant - has been applied at least in transmission in some North American markets (New York, New England, PJM[2]), New Zealand, Argentina, and Chile (Sotkiewicz & Vignolo 2005) and in Russian power markets (Abdurafikov 2009). Co-optimization of network usage and generation calls for centralized calculation of dispatch schedules for generation units. Thus, nodal pricing seems to be applied in markets falling more into a category of pool type, which is fundamentally different from the design of Nordic power markets of exchange type. See e.g. Mihaylova (2009) for discussion on market design.

[2] **P**ennsylvania New **J**ersey **M**aryland

System operation is justified to be separated from grid ownership in markets where nodal pricing is applied. That is, the more network is congested, more revenues from the differences in nodal prices occur, potentially resulting in distorted incentives.

Sotkiewicz & Vignolo (2005) discuss and analyze the potential to introduce nodal pricing also in **distribution networks** with distributed generation (DG). The rationale of this can be questioned due to the fact that distribution systems are designed to avoid congestion in order to ensure obligation to serve. However, marginal losses in distribution networks might be significant. Thus, an accelerating desire for integration of DG in the electricity networks and active partners in markets might give reasons to consider nodal pricing also in distribution (Sotkiewicz & Vignolo 2005). This could give an opportunity for economically more efficient price signals for DG location. DG integration and transforming distribution networks to be more active are also one of the drivers of Smart Grid development.

In *zonal* or *uniform* pricing systems, larger zones of networks than the price locations in nodal pricing are represented by one price. The congestion in network is managed and removed by counter-trades by the system operator. Thus, the short-term congestion costs inside a price zone cannot be seen in prices in such systems.

3 Network tariff design and structures in practice

Several practical questions have to be solved in the design of network pricing. The following sections provide with a deeper outlook on these options and internationally applied approaches to the questions in network pricing.

3.1 Classification of tariffs

In the terminology used in this report, term *tariff design* is used of the total process that determines the financial transactions between the users of electricity network services. Tariff design can be divided e.g. as in the following questions (Petrov & Keller 2009)

1. What should be priced?
2. What is the major pricing concept?
3. How to allocate costs for tariff setting?
4. What is the tariff structure?
5. Who should pay?

Tariff structure refers to a criterion of charging of single customers. This may based on consumed energy (€/kWh) or peak-load, capacity or demand charge (€/kW), fixed charge (e.g. €/month) or a combination of these. Different approaches between distribution and transmission tariffs can be seen, due to e.g. to physical differences of the functions.

In addition to practical choices presented, efficiency of regulation centrally affects a societal efficiency of the chosen tariff scheme. However, analysis of regulation is beyond the scope of this report. Interested reader might find reference e.g. in Viljainen (2005).

3.1.1 Question 1: What should be priced?

Cost components of network services include infrastructure and network costs, the operation and maintenance costs. Losses, ancillary services and congestion management have also to be included in the pricing system. However, who charges for what services and are these charges rolled over as such, keeping the cost structure, or are they embedded in the costs to the next client level? Cross-border congestions bring revenues to the TSO, how are these incomes managed?

There are also costs related to connection of facilities into networks that need to be taken into account. That is, when new generation capacity is installed, there may arise needs to install reinforcements in the grid infrastructure. If the network company takes care of it, we talk about shallow connection costs. If the generator has to pay for the grid reinforcements, we talk about deep connection costs.

3.1.2 Question 2: What is the major pricing concept?

Pricing paradigms can be divided in (i) rolled-in and (ii) incremental paradigms (Krause 2003).[3]

In the **rolled-in pricing paradigms**, all costs related to transmission are summed up in a single number, and the sum of costs is allocated between different users according to a chosen criterion. Examples of this criterion include *postage stamp*, *contract path* and *MW-mile methodologies*. (Krause 2003)

- **Postage stamp pricing.** A postage stamp rate allocates the shares of total costs of network services according to the share of power of transaction of total system peak power.
- **Contract path pricing.** Fictitious path between points of injection and receipt of electricity are determined by the system operator for transmission service users - i.e. generators and consumers. The costs of transmission are allocated according to these paths. The method requires the information of bilateral contracts between generators and consumers to be available for the system operator.
- **MW-Mile** methodologies include *distance based MW-Mile methodology* and *power flow-based MW-Mile methodologies*. In distance based MW-Mile methodology, the embedded transmission charges are assigned based on the airline distance between points of injection and receipt and the magnitude of transmitted power. A more sophisticated analysis of real power flows are used in the power flow-based MW-Mile methodology.

Rolled-in pricing methods, such as the above examples, are widely used in distribution and transmission pricing. They allocate the costs to grid users according to estimated extent of their use of the facilities. The disadvantage of the rolled-in paradigms is that they set no incentives for the reinforcements of the networks. Historically, peak demand of participants has been considered as a

[3] Alternatively, marginal and average cost pricing have been referred to as the main classes. The former falls into category of incremental paradigms, whereas the latter into rolled-in paradigms.

major driver in the cost allocation. The parameters of cost allocation may be obtained by metering but also through estimation, in a case when there is a lack of direct metering data.

Incremental pricing paradigms take into account the additional transmission cost a transaction causes to system, therefore not including the embedded costs. Timeframe considered affects the details of concepts under this category. In the long-run, all costs are variable. Therefore, long-run marginal costs (LRMC) may include e.g. investments and reinforcements in capacity, whereas with the short-run marginal costs (SRMC), capacity is assumed fixed. Estimation of long-run marginal costs calls for estimation of future energy consumption and peak-loads.

Due to the economies of scale, short-run marginal costs do not recover the fixed costs of networks even in theoretical situation. This calls for complementary charges. Theoretical alternatives for tariff structures which fulfil the cost recovery requirement include Ramsey pricing, two-part tariff and FDC. Econ Pöyry (2008) provides with an overview of the theory and options for design of tariffs for these residual charges.

3.1.3 Question 3: How to allocate costs for tariff setting?

As electricity networks consist of enormous amounts of assets, it is in practice difficult to estimate and, especially, allocate the marginal costs of electricity delivery for every period of time for every customer at every location. In theoretically optimal market case, this information should be available for market participants so that they could adapt their operation accordingly, resulting in maximal social welfare. To deal with this question, there are options used to allocate costs according to a chosen set of criteria that affect the actual costs of the power system (Fig 3), including:

- Geographical differentiation
- Voltage-level differentiation
- Time-of-use and contribution to system peak

A basis for charging different customers can be determined according to these criteria. However, highly nonlinear properties of electricity transmission and distribution, as well as complex process and principles of planning of investments make the task difficult.

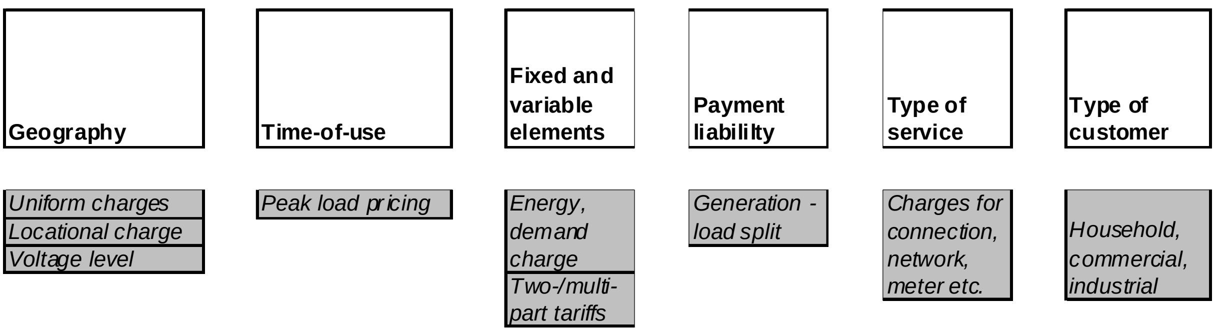

Fig 3. Possible levels of differentiation of tariffs. Examples of alternative ways to differentiate tariffs are listed in gray boxes under each criterion for differentiation

(Geography, Time-of-use, Fixed and variable elements, Payment liability, Type of service, Type of customer). (modified from Petrov&Keller 2009)

3.1.4 Question 4: What is the tariff structure?

Tariffs can be based on parameters that are more or less fixed or variable, at least in the long run. Two obvious alternatives for the basis of charging customers are energy (MWh) or capacity/load (MW). The component capacity/load charge is often referred to as *demand charge*. At least the following attributes are among choices of tariff structure.

- Energy charges
- Demand charges
- Time-of use and contribution to system peak
- Differentiation by time
- Fixed charges

Differentiation by time can result in very dynamic tariffs. The components of tariff structure may also have different time frames. For example, the energy based component may be hourly priced, while the fixed charge may be monthly or annual. In addition, new dynamic tariff structures also emerge: premiums and penalties for special situations, conditional charges, etc. This type of new tariffs may become increasingly interesting in the future, boosted by hourly metering, two-way real-time communication between energy companies and increased smartness of electrical appliances and, generally, in electricity systems characterized by Smart Grid features.

Time-varying tariff structure options include *Time of Use (ToU)* tariffs[4], r*eal-time pricing (RTP)* and *Critical peak pricing (CPP)*. The terms are used at least and perhaps more often in a context of retail sales tariffs. That is, they consider pricing of electrical energy, not the network services. However, the basic structures are also applicable in a debate of transmission and distribution tariffs.

RTP and CPP are truly dynamic pricing options. They may vary e.g. in accordance with wholesale prices of electricity. The degree of dynamics is the largest in RTP. That is, prices can vary by hourly resolution. Under ToU, the consumer price varies in a preset way within certain blocks of time (e.g. night/day). The CPP price structure presents a more recent innovative addition to the ToU price structure. That is, in CPP the ToU-like structure is completed by one more price level concerning “critical” peak hours, which the utility can call on a short notice. The number of critical peak hours is typically limited to 50 or 100 hours a year. More thorough description of different options is included e.g. in National Action Plan for Energy Efficiency (2009). For example, *Peak Time Rebate* (PTR) is a tariff structure, where customers who reduce electricity use below normal on critical peak days would be offered a rebate.

[4] Even though the price level varies by time, Time of Use tariffs are not always classified as dynamic tariffs. This is due to the fact that the price periods are predetermined and do not capture the costs of unexpected changes in supply and demand.

3.1.5 Question 5: Who should pay?

After an appropriate tariff design is set, it has to be decided how the cost burden of electricity network activities is split. In practice, this means whether the tariff is allocated to loads (consumption) only or do generators (production) also participate by some contribution.

Econ Pöyry (2008) discusses the effects of allocating the residual tariff between consumers and generators. Residual tariff refer to a part of transmission costs not covered by tariffs based on short-term marginal cost. According to Econ Pöyry (2008), residual tariffs based on maximum consumption or installed capacity will function as a tax on peak load consumption. In principle, it would also be possible to collect the residual tariffs through general taxes. In practice, payment through a scheme collected from the grid users is a common approach

It is stated in Econ Pöyry (2008) that in closed economy, who pays the residual tariff (tax) is in the long-term equilibrium indifferent from the resulting output point of view. The real burden is not affected by who pays but by the slope of the supply and demand curves. In more open economies, where more countries participate in the markets, the picture is more mixed. This is due to the fact that different principles for tariffs can distort competition and lead to a suboptimal allocation.

3.2 Objectives of tariff design

The main regulatory principles for distribution tariff design can be expressed as, according to Rodriguez Ortega et al. (2008)

- Sustainability
- Economic efficiency
- Non-discrimination or equity in cost allocation to consumers
- Additivity
- Transparency in the whole tariff design process

Some other principles are: stability of the design methodology; consistency between tariffs and the regulatory framework in each country; and simplicity.

Rodriquez Ortega et al. (2008) state “the fulfilment of all these principles may be quite complex, as some conflicts may arise: equity may limit efficiency, which cannot be achieved easily. Even if there were no conflicts, some steps of the tariff design methodology are very complex—especially, allocating network cost between all the customers.”

Even though universally optimal solutions may be hard to find and practically implement, Econ Pöyry (2008) summarizes the theoretically-derived guidelines for tariff design as follows

“Pricing of transmission and distribution of electricity should be done according to economic criteria, that is, reflect the marginal short-term costs of losses and congestion in the grid. Long-term price signals beyond these short-term signals should reflect the cost of customer-specific investments. As the grid constitutes a natural monopoly, these tariffs will however not be sufficient to cover the total

need for income in the grid. Hence, there will be a need for tariffs that provide recovery of residual costs. The allocation of residual costs between network customers should be done in a manner which distorts use of the grid and investments as little as possible. In practice, this means relatively low tariffs for generation and large industrial users, while households, the public sector and small businesses should cover the bulk of the residual costs, although there are many variations within these groups and over time. "

The suggested guidelines follow the principles two-part tariff and Ramsey pricing, where a mark-up on the energy tariff is differentiated according to the price-sensitivity of the demand for electricity, yielding the lowest loss of economic welfare. That is, a similar principle to Ramsey pricing is used for the fixed part of the tariff. Thus, greater part of the residual costs should be covered by the network customers with the least price-sensitive demand (Econ Pöyry 2008). Through real-time metering and real-time information provided in Smart Grid context, demand response and price sensitivity options may be increasingly available also to small-scale energy users (e.g. households) in the future. Therefore, it can be discussed if the basis of small-scale energy user covering the bulk of the residual costs will be as strong in the future.

3.3 Coordination of pricing schemes and actors

The implementation of theoretically optimal tariffs may be restricted by the fact that there are several companies and organizations involved. In an unbundled industry, transmission, distribution and generation of electricity are not planned by one single institution. At least the following questions arise:

- In standard models of markets, market participants take actions according to market prices reflecting marginal costs of a product. How can this information be obtained and delivered to market participants in an unbundled industry consisting of both regulated and deregulated activities?
- Deregulated actors are allowed to set their prices freely whereas regulated actors are under a surveillance of authorities. End-users' price signal consists of the sum price of all the activities, which are physically not independent of each other. What requirements and effects can this mixture set for tariff setting?

These questions are reviewed in the following sections.

3.3.1 Pass-through of the total costs of the electricity system

Location of new generators is dependent on transmission (or, in a case of DG, distribution) investments and vice versa. Therefore, it can be argued that pricing schemes should be implemented to coordinate generation and transmission investments (Rious 2008).The independency of pricing between the companies may cause overlapping of incentives of retail and network tariffs. LMP pricing (section 2.3.2) presents one option to address the coordination of pricing of generation and transmission.

When pricing schemes are designed separately between network and generation activities, as is the situation e.g. in Finland, incentives in market participants' behaviour may occur, even potentially resulting in welfare loss. This is illustrated through the following examples (Fig 4 - Fig 6).

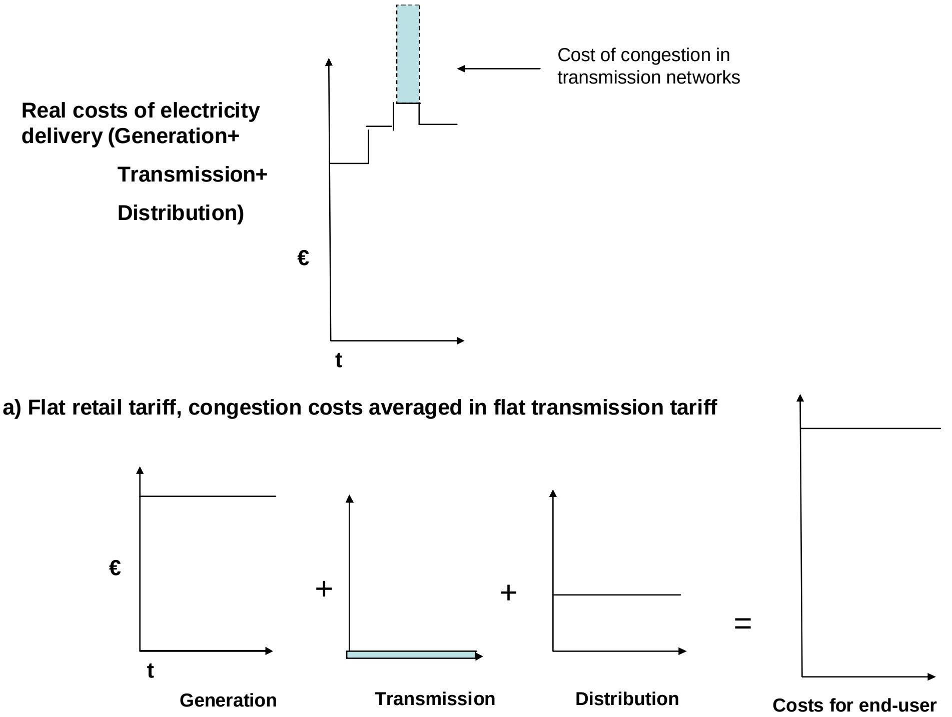

Fig 4. The effect of generation and network costs on pricing and tariffs

The issue of coordination of price signals is illustrated in Fig 4. The upper graph presents real marginal costs of electricity over a period of some hours, including short-term costs of networks. This is assumed to be the result of coordinated optimization - i.e. the maximization of sum of surpluses - of generation, transmission and distribution. Area surrounded by dashed line illustrates additional costs of electricity transmission over a smaller time period, e.g. due to congestion. In a theoretically ideal tariff structure, the whole structure should be signalled to end-user, provided that he is supposed to adjust his behaviour in economically efficient manner (e.g. through demand response technologies).

In case of flat retail and transmission rates, where the short-term marginal costs of transmission and generation are averaged over time or location in transmission tariffs, no incentives to shift loads for consumers, as seen in the right-hand-side-chart of the lower part, will occur. That is, the time of electricity use is economically indifferent from the end-user's point of view and no incentives to shift usage according to real costs exist.

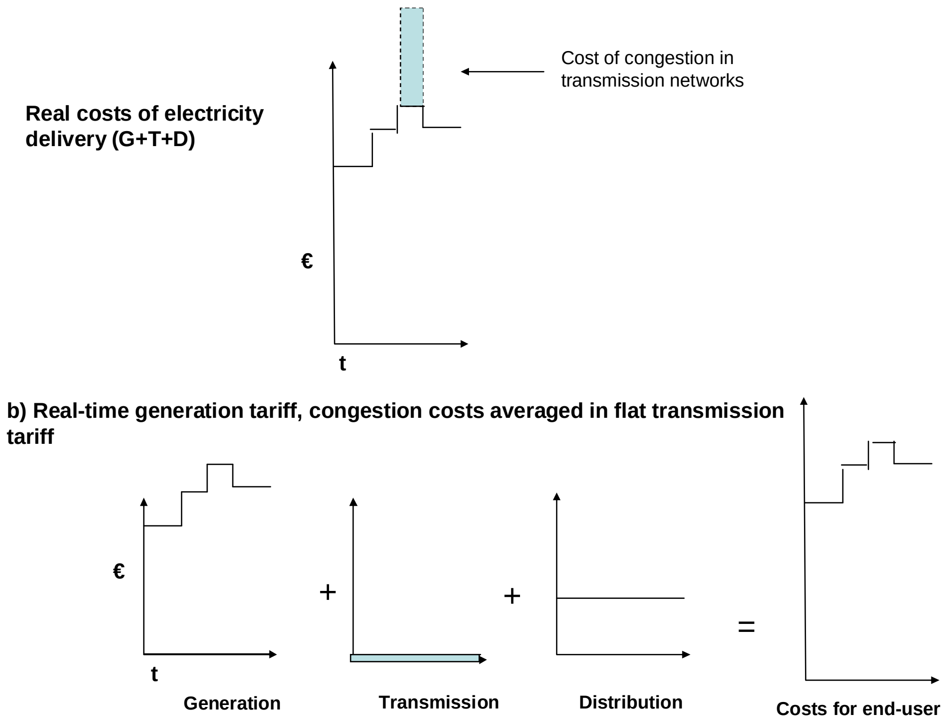

Fig 5. The effect of generation and network costs on pricing and tariffs: real-time generation tariff, averaged congestion costs

The example of Fig 5 presents a tariff structure where a real-time generation tariff is used instead of an averaged tariff. As it is schematically seen in this case, incentives exist for the end-consumer to shift load. That is, economic savings can be obtained if load is shifted from high-cost hours to low-cost hours. However, as the price structure does not perfectly reflect the upper graph of social costs, the savings are not as significant as would be the case if all the costs would be accurately rolled to the end-user.

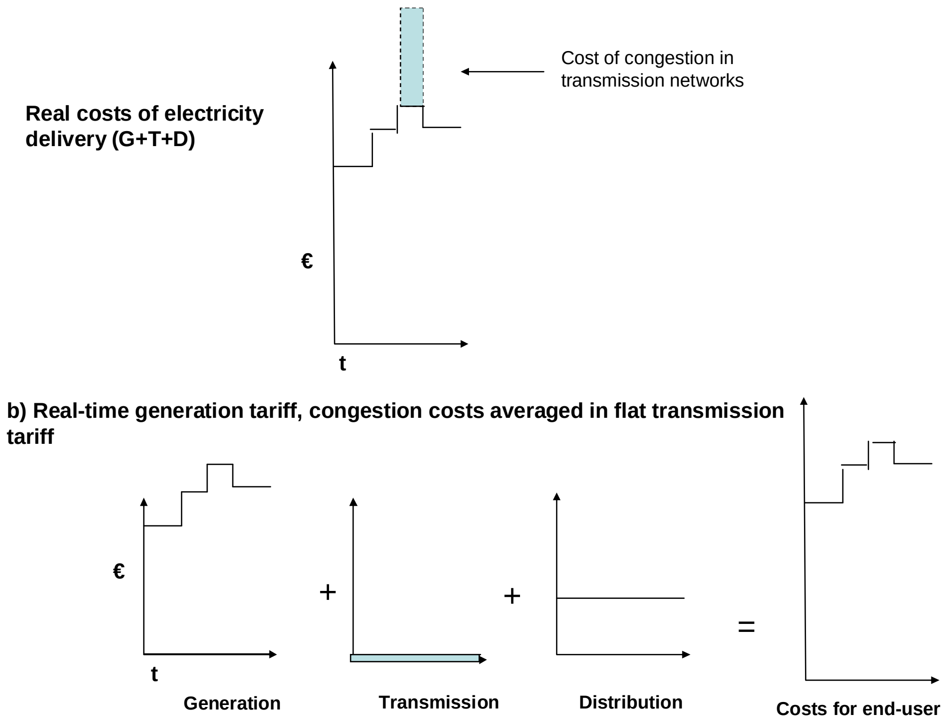

Fig 6. The effect of generation and network costs on pricing and tariffs: real-time generation tariff, averaged congestion costs

Fig 6 illustrates a case where RTP for generation and a ToU tariff with two time periods is used for transmission. It can be seen that in the example, real costs of total electricity delivery can be rolled to end-customer even accurately, providing even stronger incentives to load-shifting.

The examples of (Fig 4- Fig 6) are illustrative examples of how the whole delivery chain potentially hampers the economically efficient network tariff setting and output. In real situations it must be remembered that the situation is not this simple and, also, estimation and/or allocation of costs may be difficult. Furthermore, the scales of costs of the examples are chosen so that the effects are visible and no link to actual relation of scale of costs is presented. The primary test bed results presented in Chapter 5 give an inkling of the actual interplay between the different tariffs and their effects on the end-user.

3.3.2 Leeway of distribution tariffs in a deregulated market environment

In a deregulated environment, the presence of both regulated and deregulated actors makes the picture of “right” tariffs complicated, even if the market is assumed to be competitive and the regulation effective. In this respect, the question of an activity being regulated or not plays a major role. **Regulated actors** (generally distribution and transmission companies) are required to provide services at prices delimited by a reasonable rate of return. Furthermore, their pricing is under the surveillance of a regulator. For **business actor** (sales company or generation company), free pricing is allowed and thus profits and losses are not restricted.

Various simultaneous pricing mechanisms have a coordinated effect on the end-user incentives as shown in (Fig 4 - Fig 6) and may cause disturbance to the theoretical market mechanisms. In principle, in competitive markets, the market mechanism takes care that the price of a product (electricity) corresponds to marginal costs in the long-term (power system) equilibrium, but in reality, in unbundled systems single actors (e.g. DSO, sales companies, TSO, generation companies) have altogether different viewpoints which fight among themselves for the user's attention.

Tariff designs offer one possibility to increase the efficiency of electricity systems. To consider reforming tariffs to provide incentives for participants (reflecting marginal costs of the electricity system), the allocation of costs and benefits to participants needs to be reconsidered. This is important since actions by one actor can impact on the costs and/or benefits of other actors. For example, one can see that the end-user usage is indifferent to the cost in a pricing scheme as shown in Fig 4. Due to the flat tariff structure for end-user, no incentive to shift load exists, even if it benefits the system as a whole and, thus, in the long run, also the end-user. So even if the tariffs do not send distorted incentives/price signals, they do not steer the system towards maximizing social welfare, a goal for any theoretical tariff system.

If DSO tariffs are of a different structure than sales tariffs, the possibility exists, that the distribution tariff shifts the load, which could be disastrous to energy seller, if it increases his burden at the wholesale market, see Fig 7. Is such a tariff system in line with the market guidelines and acceptable?

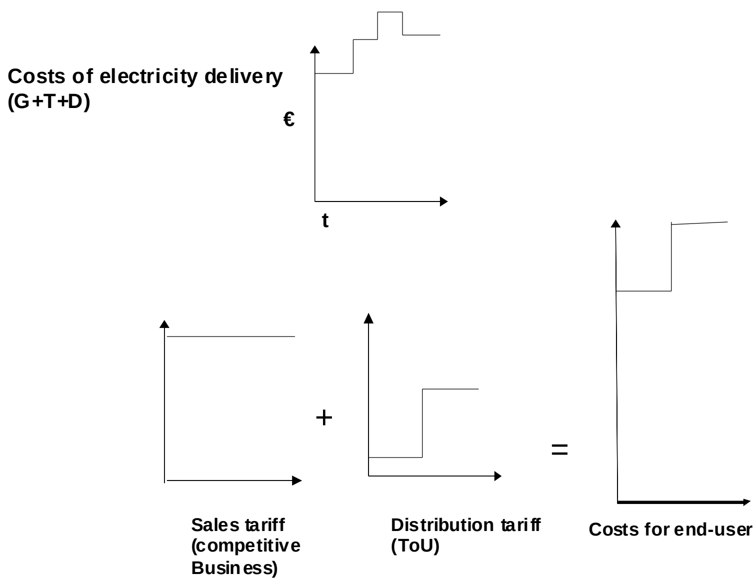

Fig 7. The effect of sales companies' and distribution tariffs to end-users' cost.

As an example of the negative consequences of sales and distribution tariff interaction, the Norwegian regulator, at least in one occasion, considered the drawbacks of time-varying distribution tariffs greater than benefits. Grande et al. (2008) describes a practical example of time-varying distribution tariff experiment. It deals with a Norwegian pricing pilot, where piloting of time-varying distribution tariffs required a special allowance from the regulator. Time-of-use distribution tariffs were decided to not be allowed at the time of the study on a general basis by the regulator. This was due to their considered disturbances to the market mechanism. The argument for a flat distribution tariff is its minimal distortion it causes the competitive sectors.

However, it is also true that ToU distribution tariffs, which increase incentives for customers to shift load from peak-load periods, are one potential measure for distribution companies to improve their cost efficiency. Thus, since distribution companies are required to operate cost-efficiently, it can be argued that ToU distribution tariffs should be allowed. This would be the case especially if welfare loss from the disturbance of the market mechanisms is considered smaller than benefits from increased cost-efficiency of distribution. ToU distribution tariffs have been in use in Finland for decades, and the issue with them has mainly been that they have had rigid structures allowing only one specific ToU construction per meter. With modern hourly metering, this is no problem anymore, and as can be seen in Chapter 5, end-user incentives are decidedly smaller without ToU distribution tariffs. Even if ToU tariffs are no problem, more real-time dynamic distribution tariffs may well be.

Dynamic tariffs and enhanced utilisation of real-time data are increasingly justified in Smart Grid environment. To obtain a theoretically justifiable and efficient tariff system, coordination of the pricing schemes of sales and distribution are of essence. One could think, as an extreme solution, to integrate the activities of retail and distribution so that there would be only one tariff for the end-user. If sales and distribution are co-optimized by one company, no distortion to the end-user prices and the market would occur as a result of introducing dynamic tariffs. This would mean going back to the old days, which could be challenging to implement. It would also suggest that market mechanisms operate less efficiently than central planning under real world conditions, not just as a theoretical abstraction. In practice, however, central planning systems have been far from being perfect, while the market mechanisms have an excellent track record in retail markets, especially looking at the Nordic power system (which has not had to deal with introducing new marginal production capacity, i.e. condensing power, yet).

For a less radical solution, one could think of distribution companies being obligated to compensate sales companies for the accrued losses that load shifts done by the distribution side results in. In practise, if the negative consequences of distortion to end-user price are considered larger than efficiency gains from time-varying distribution tariffs, there is no justification for introducing them.

The from the market perspective, easy solution would be to have the DSO's buy any necessary load shifting from the sellers (e.g. aggregators), especially considering market or balance market timescales (from 15 minutes up). From the operation and security of the networks perspective, load shifting should in many areas have the DSO's and/or even the TSO's approval, as for example the EU project ADDRESS (2009) suggests.

3.4 International practises of tariffs

Theoretically justifiable methods to price network services under different assumptions can be derived from economics. This is discussed in the preceding sections. However, considering any tariff structure, it must be kept in mind that it can be argued

- Do theoretically derived prices provide "the best" solution in real-world environment?
- To what extent can theoretically derived pricing be implemented in real-world systems? Barriers may appear considering data availability, metering, cost assessment, cost allocation, efficiency of regulation, availability of information, legislation, etc.

Economic theory (section 2.1) includes assumptions that have been criticized to be loosely met in real-world electricity markets. Real-world electricity markets are always more or less imperfect, different from the theoretical ideal. Perfect market information or perfect competition steering market participants' decisions are examples of such assumptions.

The theoretically derived optimality of principle of marginal pricing is not unquestionable in imperfect real-world electricity markets. The claim that marginal cost-based pricing gives socially optimal result real-world electricity market outcome is criticized e.g. by Lazare (1998), and flaws in theory are suggested by Keen (2004).

In practice, compromises between theoretical efficiency and practical feasibility as well as trade-offs between the objectives of tariff design are usually required. As Leveque (2003) states: "There is a long way before discrepancies between textbook tariffs and practised tariffs will be reduced". In the following sections, a review of reality transmission and distribution pricing is presented. According to Rodriguez Ortega et al. (2008), traditionally, sustainability of electrical companies has been the main goal in tariff design. This leaves economic efficiency, sustainability, non-discrimination or equity, additivity, and transparency to a lesser importance.

3.4.1 Differences in transmission pricing in Europe

Main characteristics of transmission pricing in European countries are presented in Table 1. Taking a closer look to transmission pricing reveals differences in practices applied in Europe, e.g. to solve the compromise between practical feasibility and theoretical efficiency, as well as trade-offs between different objectives in tariff design.

The following list (Petrov & Keller 2009) provides with some examples of the differences. For more extensive information, see Fig 8 for a more complete list of energy/demand based transmission charges in Europe.

Marginal versus average cost

- Marginal cost used in Great Britain (LRMC) and Norway (SRMC)
- Average cost used in Germany and Austria

Locational elements
- Locational elements in Great Britain, Ireland, Norway
- No locational elements in Germany

Tariff design (energy and/or demand charges)
- Demand charge in Great Britain
- Energy and demand charges in Germany
- Energy charges in Bulgaria, Ukraine

Transmission losses
- Excluded from transmission charges - in Great Britain and Ukraine
- Included in transmission charges in Germany and Austria
- Locational signals via transmission losses – Norway

System operation cost
- Explicit price control in Great Britain
- Integrated in transmission price control in Germany

With respect to payment liability, it seems to be more common that the liability is set to load only. This is the case in 19 countries of the countries considered. According to Table 1, joint liability, where payment is also allocated to generators, is in use in Austria, Great Britain, Ireland and Northern Ireland, Finland Norway, Sweden and Romania and with the smallest shares in Denmark, Poland and France. The share of generation liability is the largest in Norway (35%) and Sweden (28%).

Table 1. Main characteristics of the TSO tariffs in Europe (ENTSO-E 2010).

	Sharing of network operator charges		Price signal		Are losses included in the tariffs charged by TSOs?	Are the system services included in the tariffs charged by TSOs?
	Generation	Load	Seasonal/ time-of-day (1)	Location		
Austria	15%	85%	-	-	Yes	Through a specific component to generators
Belgium	0%	100%	xxx	-	Not included for grid>=150 kV	Tariff for ancillary services
Bosnia and Herzegovina	0%	100%	-	-	No	No
Bulgaria	0%	100%	-	-	Yes	Yes
Croatia	0%	100%	x	-	Yes	Yes
Czech Republic	0%	100%	-	-	Yes	Yes
Denmark	2-5%	95-98%	-	-	Yes	Yes
Estonia						Yes
Finland	11%	89%	x	-	Yes	Yes
France	2%	98%	-	-	Yes	Yes
Germany	0%	100%	-	-	Yes	Yes
Great Britain	27% TNUoS Tariff (2) 50% BSUoS Tariff (2)	73% TNUoS Tariff (2) 50% BSUoS Tariff (2)	xx	TNUoS - locational; BSUoS - non-locational	No, recovered in the energy market	Included in BSUoS Tariff
Greece	0% Use of system 0% Uplift charges	100% Use of system 100% Uplift charges	x	-	No, recovered in the energy market	Included in Uplift charges
Hungary	0%	100%	-	-	Yes	Tariff for ancillary services
Ireland	20%	80%	-	Generation only	No, recovered in the energy market	Yes
Italy	0%	100%	-	-	No	Yes
Latvia	0%	100%			Yes	Yes
Lithuania	0%	100%	-	-	Yes	Yes
FYROM	0%	100%	-	-	Yes	Yes
Nertherlands	0%	100%	-	-	Yes	Tariff for ancillary services
Northern Ireland	25%	75%	xxx	-	No	Tariff for ancillary services
Norway	35%	65%	xxx (via losses)	Location	Yes	Yes
Poland	0.60%	99.4%	-	-	Yes	Yes
Portugal	0%	100%	xx	-	No, included in energy price	No, included in energy price
Romania	20.69% Use of system 0% system services	79.31% Use of system 100% system services	-	6 G zones = 6 G tariff values 8 L zones = 8 L	Yes	Tariff for ancillary services
Serbia	0%	100%	x	-	Yes	Yes
Slovak Republic	0%	100%	-	-	Through a specific fee	Through a specific fee
Slovenia	0%	100%	xx	-	Yes	Tariff for ancillary services
Spain	0%	100%	xxx	-	No, included in energy price	No, included in energy price
Sweden	28%	72%	-	Location	Yes	Yes
Switzerland	0%	100%	-	-	By a separate tariff for losses	By a separate tariff for losses

(1) The "X" indicates time differentiation. With one "X", there is only one time differentiation ("daynight", "summer-winter" or another one). With two "X" (or more), there are two (or more) time differentiations.
(2) TNUoS: Transmission Network Use of System; BSUoS=Balancing Services Use of System

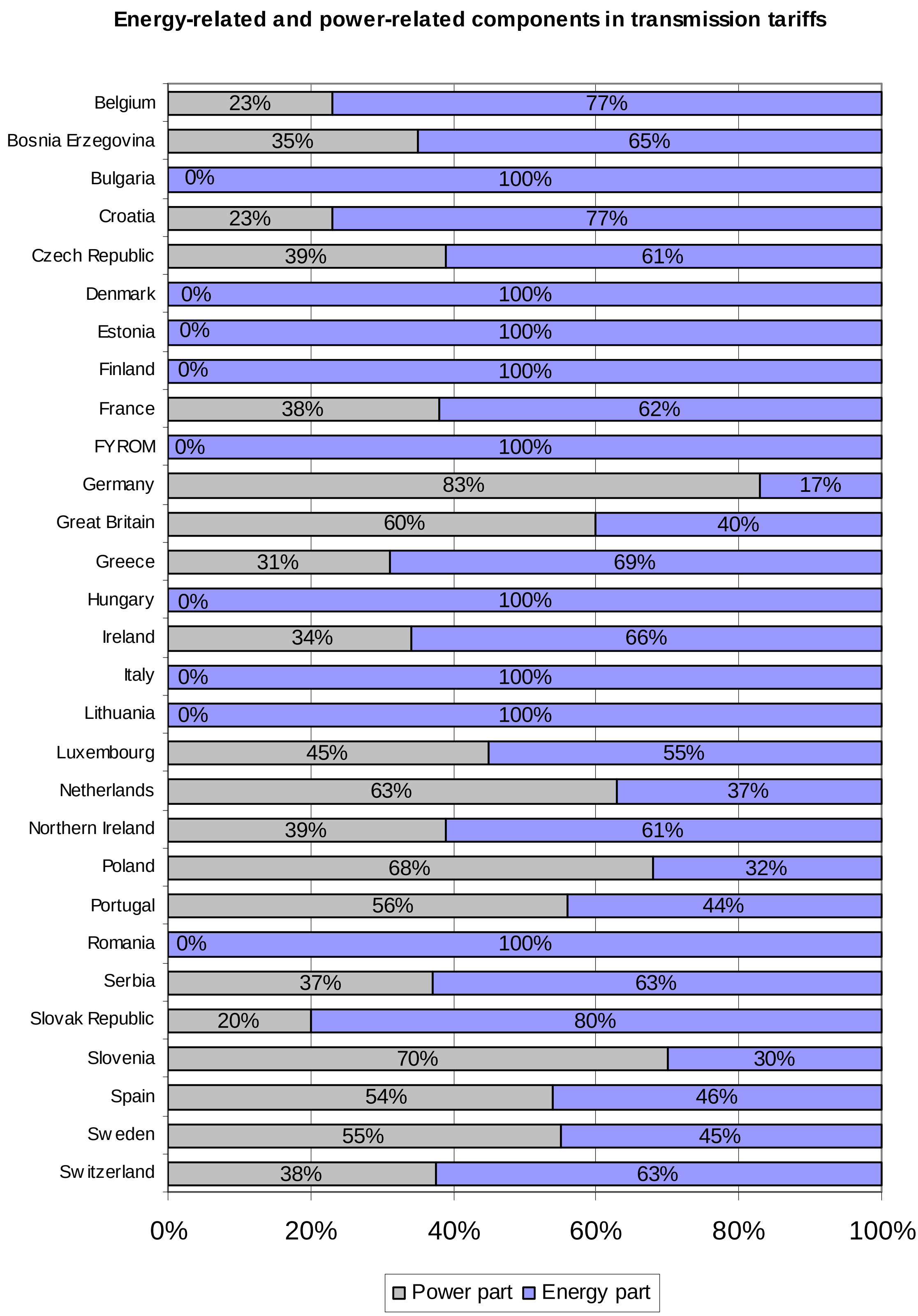

Fig 8. Energy and power related components in the transmission tariffs in European countries. (Source: ENTSO-E 2010)

3.4.2 Differences in distribution pricing in Europe

Taking a closer look to distribution pricing reveals different practices applied in Europe. The following list (Petrov & Keller 2009) gives examples of the differences with respect to distribution pricing in some selected countries (Great Britain, Portugal, Germany, Czech Republic and Austria).

Locational elements

- Prices are usually on regional basis
- Prices are differentiated by voltage levels but without further geographical differentiation

Marginal versus average costs

- Marginal cost used in Great Britain and Portugal
- Average cost used in Germany and Austria

Tariff design (energy and/or demand charges)

- Demand and energy charges used elsewhere
- Standing charges (Great Britain)

Distribution losses

- Included in distribution charges (Germany)
- Included in distribution charges using a separate losses charge (Austria)
- Excluded from distribution charges

Time-of-use pricing

- Elements of time-of-use charges in Austria and Portugal
- No time differentiation in Germany

Differentation by voltage level of connection

- Used elsewhere
- Some countries in Eastern Europe apply single uniform charges across networks

3.4.3 Finland

Finland is an unbundled market area, where the transmission, distribution and production and sales are separated. When we discuss network tariffs, then the TSO has a lot more going on for him than DSO's, see Fig 9.

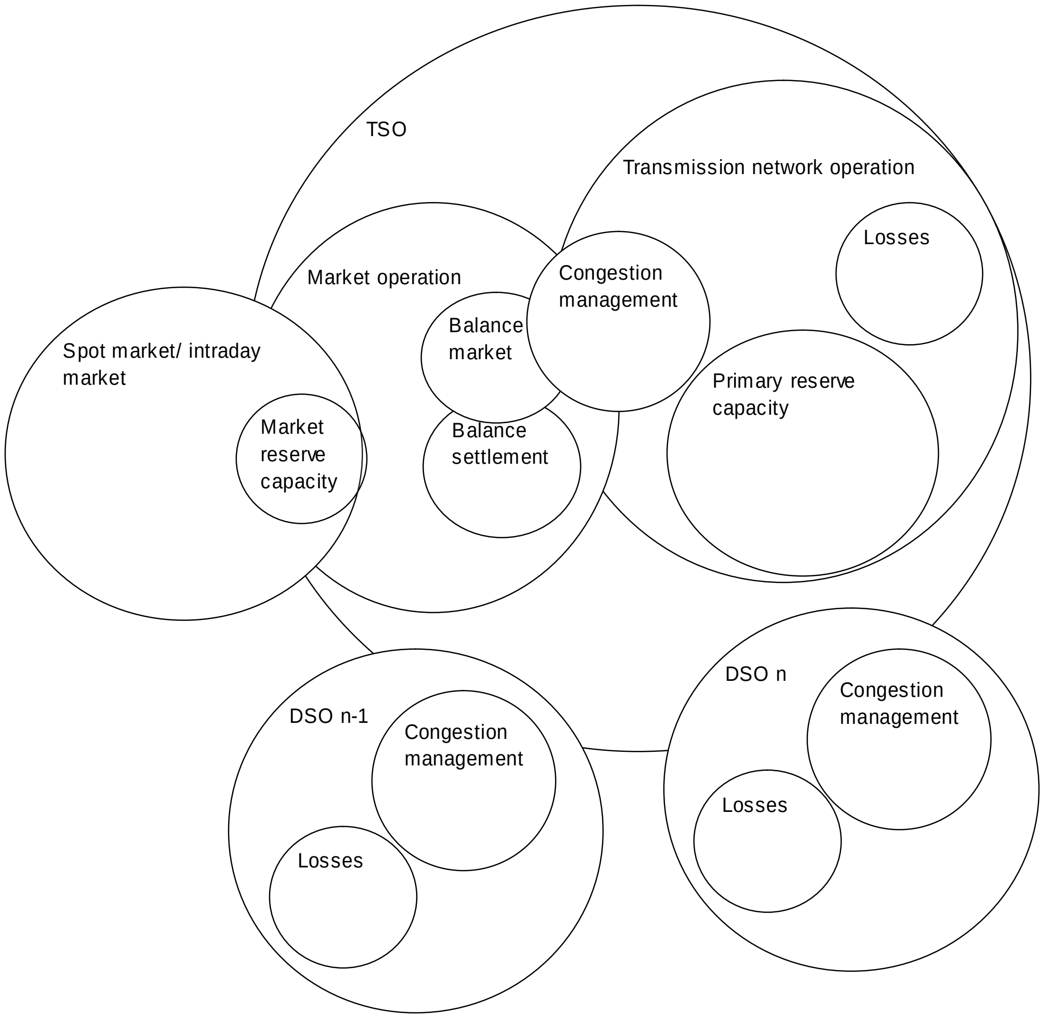

Fig 9. The TSO and the DSO's relations to each other and to the market. The System Operator (=TSO in Finland) manages the market operation including balance management, cross border transmission, and the facilitation of the spot market operation. DSO's interest with dynamic end-users lies mostly with congestion management and line capacity issues and in minimizing TSO tariff costs.

Sellers

Energy wholesale in Finland is mostly done through the Nordic spot market, Nord Pool. Bilateral contracts are also possible. Finland is preparing for a Nordic common end-user retail market.

The Finnish retail market is working quite well, at least if it is evaluated using retail sellers' profits as indicator. The profits are very small and all too often negative.

Electricity retail sellers, at the moment, use one price or time-of-use (ToU) tariffs, whereas market price (spot price) based tariffs are on their way. In fairness, they have been available for a decade, for example by Turku Energia, but have not reached wide-spread popularity. With hourly meters for all, things can and will change.

TSO
Fingrid is the owner and manager of the national transmission grid and serves as the system operator.

Fingrid manages the system balance in cooperation with other Nordic transmission companies. There is a joint balance market, although every partner is in the end self responsible for their national balances. The balance settlement takes place nationally. The costs of frequency controlled normal reserves are allocated to the balance costs (market side).

As system operator Fingrid is the one most interested in seeing very short term - less than an hour- demand responses, if the responses come cheaper than what is at the moment offered at the balance market.

However, at the moment, to take part in the balance market the offers have to be at least 10 MW and the respond time less than 15 minutes. The solution voiced at the time for small end-users to partake in the balance market is through aggregators, though none exists at the moment. The future might be different, if suitable systems for confirming actual responses and transferring the gains are developed and if the demand responses en masse can be seen as reliable.

System reserves are common Nordic, thus lowering the burden of individual countries. Finland’s share is around 900 MW. 90 percent of the costs of frequency controlled and fast disturbance reserves are allocated to the network service and are thus part of the grid fees.

DSO’s
There are 90 distribution network utilities, mostly owned by municipalities. Distribution networks have a widespread automation in use already (Smart Grids 1.0), but, for example, lack in experience with smaller DG installations. Large DG is quite common, as Finland has a plenitude of combined heat and power (CHP) plants both for district heating as well as in the industry sector. DSO’s have to pay Fingrid a seasonal ToU consumption fee for all consumption within the distribution network and a use of grid fee for power transmitted to and from the grid (different fees depending on if to or fro).

4 Smart Grids: implications for tariff design

Smart Grids (see e.g. EC (2010) for general description of the concept) can be described as the aim to benefit from digital and communications technology - to create added value to the electricity system. In addition to end-user online (hourly) metering and two-way communications, traditionally passively managed top-down distribution networks will become more and more actively managed networks with production and flexible loads.

The concept of SG has been developing hand in hand with the rising activity of end-users through distributed energy resources (DER), which include distributed generation (DG), end-user energy storages, and demand response (DR).

From the power system’s point of view, investments in power production from renewable energy sources (RES) take place on all voltage levels, including DG at small end-users and as well as large grid connected offshore wind power installations. Whereas increasing amounts of DG put demands on the distribution networks and their automation, large wind power parks put demands on the transmission network and, due to varying and hard to forecast production, on the operation and balancing of the power system.

Tariffs will have to become more dynamic and more steering to benefit from the SG and the DER developments while counteracting the power system impairment brought on by increased intermittent production and decreasing regulable capacity. Even though it seems difficult to find a universal solution, it is discussed in this Chapter, how the introduction of Smart Grids might enable new implementation possibilities of theoretically supportable ideas of tariff structures.

4.1 Emerging options for network tariffs

Earlier in this report, the theoretical basis of and practical solutions to network tariffs are discussed. The review is done in order to identify the theoretical framework for tariff design.

The question of how implementable any tariff system is relates e.g. to metering and grid management practises. The potential of evolving and penetrating technology brought by Smart Grids is, in this respect, massive.

Currently, the connection between marginal costs and prices in electricity sector it is generally weak, but more so in a regulated market. This is partly due to the fact that estimation of marginal costs of electricity services is not straightforward, especially when looking at the network activities of the electricity supply chain. The marginal costs are time, voltage level and area dependent. Distribution networks consist of hundreds of thousands of assets (Rodriguez Ortega et al. 2008) (substations, wires etc.) and the costs of their operation, management and investments can not be straightforwardly allocated to individual end-user tariff structures or items. The situation could potentially be partly overcome by SG, insofar that some of the costs can be allocated directly to the users most responsible for them, which is the key issue of this report. Smart Grids mean more sophisticated metering and communication technologies, making tariffs that are more transparent, more economically efficient (cost-reflective) and more equitable (avoiding cross-subsidies) possible.

More accurate (hourly) consumption measurement is one of the most obvious enablers of new tariff structures. Noteworthy, advancements in metering technology, utilization of information, and progress in market liberalization improve the potential of pinpointing marginal costs of generation, transmission and distribution and allocating them to the initiators. The possibilities of new metering technologies in tariff structures are further discussed in Irastorza (2005).

The following arising Smart Grid options and needs can be identified when reforms in tariff design are considered.

- Options arising:
    - Hourly resolution of consumption data (AMR)
    - Real-time information to market participants

  - Automatic, price-responsive control of appliances and energy storages
  - DG at end-users
  - Benefits from active end-users

- Potential needs:
  - Non-discrimination: e.g. in high cost hours consumers with a low usage should not have to subsidize those with a high usage
  - Metering-based capacity (demand) charges for all
  - Explosion of DG at DSO level
  - Incentivize active end-users

4.2 Other developments of the power system - implications for tariffs

Electricity from renewable energy sources (RES-E) will increase in the coming years in the EU (Ruska & Kiviluoma 2011), but also in Norway. The impacts on the Nordic power system are noteworthy. Variable RES-E, and mostly variable due to quite stochastic factors such as the wind, needs regulating power and flexible power capacity. Regulating power is needed to account for the forecast errors in the power balance due to the high forecast error for variable RES-E one or two hours before delivery. In addition, regulating power is also needed to accommodate for the daily or weekly variability of variable RES-E. Usually hydro power is used and can be used for short term variability management, but larger intraday or intraweek variations need variable power production, for example condensing power plant capacity.

4.2.1 Nordic power production scenarios

Setup

A good way to assess power plant capacity development is to simulate how the power plants would be used in the future. For this purpose we use VTT's Electricity Market Model (VTT EMM; for a model description and use, see e.g. Unger 2010, Forsström et al. 2010, Ruska & Koreneff 2009). VTT EMM emulates the system price on an aggregated time level, using three intraweek time slots, by optimising the power production based on fuel prices, cross-border transmission links to outside the market area, and available power capacities. The monetary value of water in the hydro power reservoirs is calculated using a dynamic optimisation algorithm and using the water values, the production is calculated using a linear optimisation model based on expected incremental costs of power plants.

Using VTT EMM, Nordic power market scenarios for 2020 and 2030 were formed based on aforementioned RES-E forecasts supplemented with low-keyed estimates for Norway. A normalized year 2010 is used as comparison. Fuel prices were assumed to be invariant at approximately today's level, e.g. the coal price used was 11.5 €/MWh. The Nordic demand was kept in the 404 ± 3 TWh range.

Results

The production according fuel category is shown in Fig 10. RES-E production will increase with roughly 35 TWh by 2020 and with 50 TWh by 2030. Stochastic variable RES-E, mainly wind power, will increase with approximately 20 TWh by 2020 and 30 TWh by 2030, but these figures are to be seen more as conservative than as radical. The share of fossil fuel generated electricity will diminish from 15 percent to 7 to 8 percent.

Even more interesting, condensing power production will decrease clearly, from 20 TWh to 6 TWh in 2020 and 5 TWh in 2030, see Fig 11.

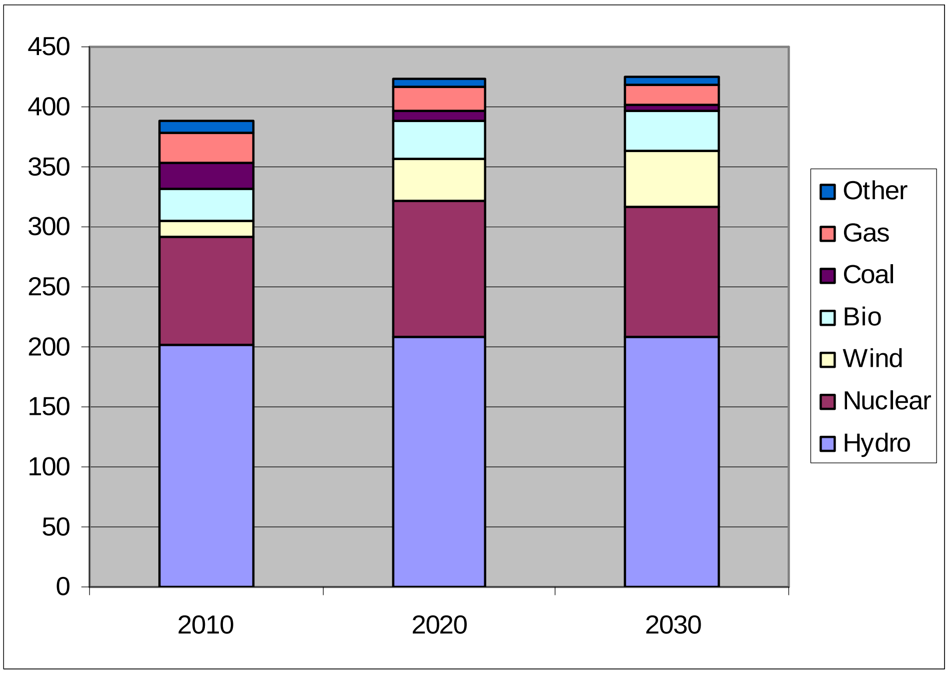

Fig 10. Estimated electricity production in the Nordic area in 2010, 2020, and 2030 according to fuel type.

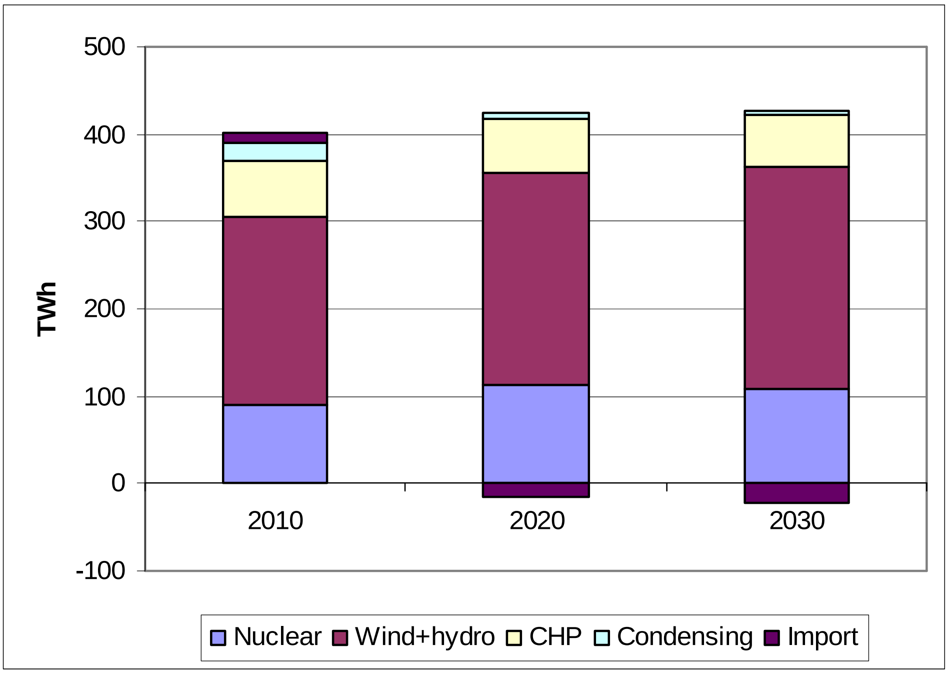

Fig 11. Estimated electricity production according to production type in the Nordic system in 2010, 2020, and 2030.

As the result figure shows, fossil fuels are used very little in the Nordic power system and, looking at condensing power production, almost not at all. Of course, one should be careful interpreting the results. Wind power variability is not seen in these results, as the time scale and the model set-up in consequence result in a constant and invariant wind power production. Also, as only cross-border transmission lines are included, but not intra-Nordic congestions, this means, that condensing power plants will be in use significantly more than the results here show. However, the scale is a good indicator of the profitability. The utilisation rate will not be high. A production of 1 TWh corresponds to an utilisation rate of 2000 hours for a maximum load of 500 MW. At the same time, there is nearly 15 000 MW of wind power installed in the Nordic countries in 2020.

The resulting minimum and maximum prices (for 2020, see Fig 12) don't fluctuate as much as expected, mostly because they describe the system price[5], but also because it is assumed that hydro power is able to balance intermittent (wind) power is intra-weekly without problems thanks to the hydro reservoirs. In reality, these conditions will be difficult to meet with the amounts of wind power capacity expected. However, additional research on this topic will be continued in the SGEM 2 Funding Period using the Wilmar model, which includes Nordic area internal congestions.

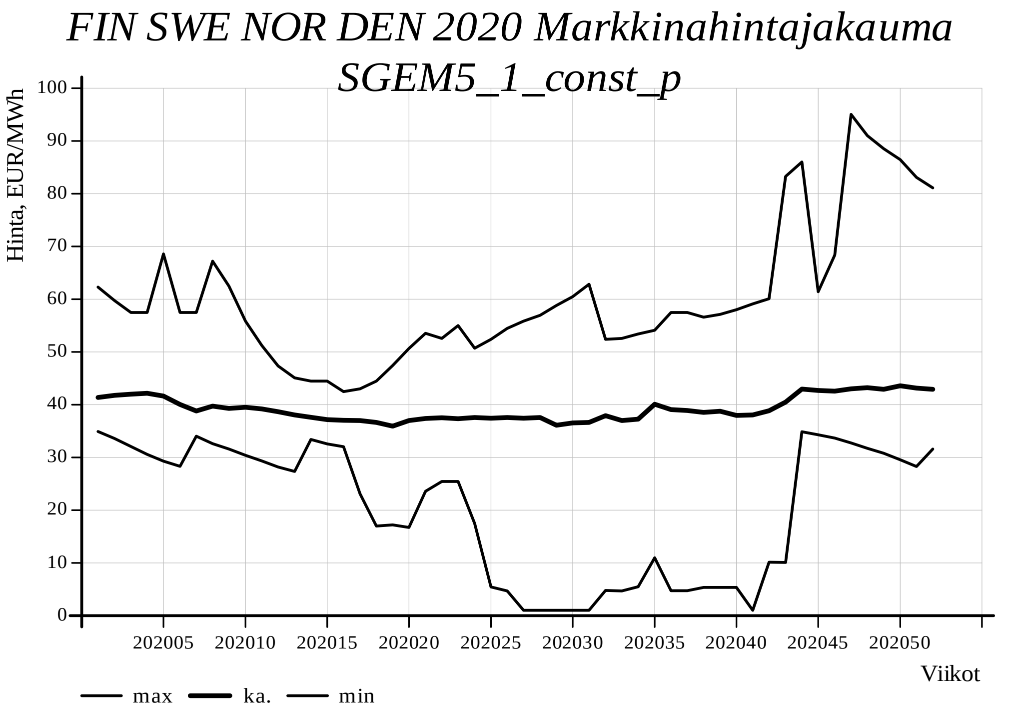

Fig 12. The Nord Pool system price (as weekly averages) estimated for 2020 with VTT EMM. Min and max represent the weekly high and low hour prices.

[5] The Nord Pool system price is the spot price which would be in effect assuming no internal congestions in the Nordic countries.

4.2.2 Impact of flexible loads on system costs

According to Ruska et al (2010), a future large scale deployment of electric vehicles (EV) seems possible. The impacts of large scale use of electric vehicles on the power system in 2035 were studied (partly in SGEM 1 FP WP 3.3) from the perspective of power generation and electricity markets. Smart charging of EVs created a system benefit of 227 €/vehicle/year compared to immediate charging, for instance due to the diminished demand for system reserve power capacity.

However, even though the advantages of smart charging to the power system were estimated to be significant in the future, a single electric vehicle user doesn't experience similar benefits in the nowadays system. Assuming the user has an hourly spot price dependent energy tariff and a time dependent distribution tariff, he saves approximately only 35 € per year, just 10 cents a day. One of the questions for the future will be how to extend the system benefits from smart charging to an increasing degree also to the single electric vehicle owner.

4.3 Implications for the tariff design and tariffs of the future

The way the power system is now heading, with recessing amounts of regulating production capacity such as coal condensing power plants at the same time there is an increase variable and intermittent production from wind power, loads contributing to local or system peaks will have a large cost impact. On the other hand, active measures to reduce peak loads will become more and more important. The need for adjustable actors is increasing.

The need for adjustability cannot be seen as a problem concerning solely the deregulated wholesale/retail part of the market, as it is a system operation issue involving both regulating capacity as well as peak load capacity. System operator tariffs will therefore have to reflect on the capacity needs, possibly constructing tariffs that lower the peak demand, increase load flexibility and/or even gather funds to enable premiums to flexible production capacity. Through the transmission network tariffs, these elements could be passed down to the distribution network tariffs and to the end-users.

For the tariffs, this means that some sort of capacity/ peak load/adjustable load based tariff elements will increase, elements that shift the loads to more suitable hours. The elements can be in the form of rewards or penalties or a combination of these.

4.3.1 Demand side integration

The user loads are and will experience significant changes in the following decades. Energy efficiency is targeted to improve, heat pumps will change the electricity usage for heating in electric and non-electric heated houses, distributed generation is expected to increase, and electric vehicles are on the coming.

As noted above, all parties will potentially profit from increased demand flexibility. In this respect, one of the main benefits from SG will be improved demand side integration (DSI; what used to be called demand side management (DSM) in a more regulated system). Automatic meter reading and two-way communications have the possibility to activate all end-users, not only the very large ones. The transmission and distribution networks can benefit from the activeness of small end-users. In addition to bilateral load control contracts (directly or through aggregators), the design of the network tariff offers many possibilities.

4.3.2 DSI tariffs

International experiences concerning pricing mechanisms and DSI are widely referenced in Evens & Kärkkäinen (2009) and will only be shortly reiterated here. Although most experiments are from monopolistic environments, bundled power systems, or purely retail, they give a hint of the ingenuity which can be put into tariff structures.

The challenge of allocating the costs and/or benefits of DSI actions and coordinating the distribution and sales tariffs is a difficult nut to crack. End-users' DER are potentially beneficial both for the distribution and sales companies, end-customers and also, to the whole system. Thanks to DER, a distribution company could reduce peak loads and postpone its investments to grid; a sales company could acquire less expensive production and more volumes from low-priced hours, potentially increasing its profit and influencing the set-up of the production capacity; end-user could cut his electricity bill. Thus, the efficiency of the whole system could be improved, if DER resources would be taken into use.

Price-based demand response refers to changes in load by end-users in response to price changes (RTP, CPP, ToU), while incentive-based demand response refers to programs by utilities, load serving entities, or regional grid operators which give separate load reduction incentives to the end-users. Most incentive-based DR programs specify a method for establishing the baseline energy consumption level of end-users against which their DR magnitude can be verified. Just to be involved in the program may itself bring benefits to the user, but on the other hand, failing to respond might result in penalties.

Some interesting examples given by Evens:

- two-tiered tariffs with baseload priced according to ToU and deviations from base load according to spot price
- fixed-period CPP, where the time, the duration and the number of calls per year are predetermined, but the specific days are not (for example, EJP and Tempo by EDF (France))
- variable-period CPP, where the time, the duration and the number of calls per year are not predetermined
- critical peak rebate (CPR) is the CPP version of the first item, that is, a fixed tariff with rebates for load reductions during critical peak periods
- demand side bidding for the balance market with or without availability payment
- ToU with concentration bonuses (ENEL): the larger share of energy is in the desired time slot, the larger the monthly/yearly discount
- fixed price with RTP-based return option
- direct load control (DLC)

- RTP with a price cap, a guarantee (paid for by the customer or not) for the average price over a time period
- RTP with a Contract for Differences (CfD); the average RTP over a determined perion of time is fixed
- RTP with a price collar, that is, a roof and a floor price limit

The critical peak rebate tariff in Ontario Energy Board is a good example of a DSI tariff. For activity, that is, for getting the load below the baseline, a rebate is rewarded to the end-user. The question of how to determine the baseline is interesting. Usually it is based on the level of a set of previous non-events, using for example the three highest (Anaheim Public Utilities) or the last five (San Diego Gas&Electric). Because critical days are the most extreme, the San Diego method's baseline underestimates the critical peak. Analysing existing data, Ontario decided to use the San Diego method's baseline multiplied by 125%.

4.3.3 Capacity related tariff example

It is the duty of the system operator to make sure that we have enough controllable and regulable capacity also in the future. Up to now it has been done by supporting a few older condensing power plants, which otherwise would have been off the market, as market reserve capacity. It is very possible that, in the future, this support will concern all existing condensing power capacity. As the need for them will become more and more limited, one possibility is that the system operator supports all regulable condensing capacity, being it coal power plants or auxiliary condensers in CHP plants. For example, the support premium would only be paid, if the capacity has bid to the market at least 95% of the hours in a month at a price less than promised. There could be, for a desired amount of capacity, quarterly bid competitions for the support. The bids would be promised maximum prices, and the lowest would be selected.

To finance this or other capacity schemes, the costs could be covered by CPP items in the TSO tariffs (e.g. market place fee for all loads). The critical peak pricing item, for example directly related to the peak load such as € per critical peak kWh/h, could be directly passed on by the DSO to the end-user or not, depending on if the distribution network has opposite interests or not. An active demand could then react and thus avoid the cost and, at the same time, lowering critical peak.

Even more passive end-users without DER could benefit. This can happen through the use an ingenious mechanism, a software fuse. A software fuse can be set in a modern meter to a lower power level than the physical fuse, thus guaranteeing that the wanted maximum load level is not exceeded. It is in use in some networks.

4.3.4 Conclusions on SG and network tariffs

All load changes will affect the need for capacity (production including regulating and reserve power, transmission, distribution), one way or the other. Some load changes might increase the intraday flexibility of system significantly; for example, electric vehicles equipped with smart charging and vehicle-to-grid (V2G) properties show tremendous potential, but end-user heat storages should not be forgotten. This end-user flexibility is usable for all parties, for the distribution network to, among others, avoid raising line capacities, for the system operator as regulating or reserve capacity, and for the market as price elasticity and inexpensive regulating power. Whereas monopolistic systems could optimise the usage of the flexibility for the various purposes both in the short and the long run, a deregulated and unbundled power system has to, or at least should, use market mechanisms.

A problem sometimes encountered in an unbundled situation is to know who (distribution system operator) operates the actual load control and among whom (TSO, distribution system operator, retailer, aggregator) and how the costs and benefits are shared (Evens & Kärkkäinen 2009).

With SG, information can be delivered to the end-user online and automatically from the market actors directly or through intermediaries such as aggregators. The delivered information can be control signals for various devices, giving the control (and part of the gains) of the load to the outside, but, on the other hand, it can be direct price signals. If it is price signals, then the end-user has to optimise his behaviour according to his minimum total costs, taking all the tariffs into account: taxes, seller, DSO, and why not in the future even TSO balance premiums etc., only as long a they are known sufficiently in advance to all the participants, also the seller.

5 Tariff test beds

Tariffs determine both the customer’s behaviour insofar the load shows price elasticity, the end-user costs, and the incomes to the tariff owners. Tariff test beds are tools developed to analyse e.g. the financial effect of different tariff structures. As both the loads (due to electric vehicles, heat pumps, low energy houses etc.) and the tariffs and their structures are changing, tariff test beds have to be updated and remodelled and new test beds created.

The KOPTI test bed used in SGEM WP5.1 and its results are, as an example, described in more detail later in this chapter.

5.1 Generally on test bed set-ups

The test bed is the better the closer it simulates the real world. With modern computer calculation capacity, simplifications should only be used with care. Most of all, prices and loads should be synchronized. The targets for the set-up could well be:

1. use hour time series
2. use a freely selected calendar frame or a fixed calendar year
3. loads and prices should match selected calendar frame
4. items affecting the end-user behaviour should be included (for load response or dynamic loads)

Hour time series are superior to aggregated time steps because, if not else, at least the spot price is hourly. A fixed calendar year is suitable, especially if there are a lot of load measurements available, but the fixed year can also be set into the future. To use a selectable calendar frame gives more freedoms but is more cumbersome. The main point is that all the time series should suit the same selected time frame.

5.1.1 Loads

With AMR, measurement point specific load data is available, if needed. If the calendar frame, for example, is from another year, there is the possibility to either use a dynamic single load profile or to just forecast the selected load. For a comparison and assessment of these two approaches, see Koreneff (2010).

Not all loads have measurements behind them, and one simplification could be to use load profiles. In this, reasonable load profiles are of essence. The most commonly used load models in Finland, 46 types, (SLY 1992, Seppälä 1996) are quite restrictive when we keep the various load changes and new load types in mind. Therefore, a new load profile system based on sub-load building blocks was introduced as an idea in the INCA-project (Koreneff 2010). Sub-loads (large and meaningful ones, e.g. hot water, heating, auxiliary heat pumps, household electricity, end-user DG) are used as building blocks -including negative ones- to create the sum load at measurement point. It will be prototyped and assessed in SGEM 2 FP WP4 in 2011-2013 using new load data and modelled loads from SGEM 1 FP and 2 FP.

The most commonly used form of load profiles is having a system of two index series, the outer given the season variation with two-week indexes and for each two-week period having a inner index series with 72 values (weekdays, eves, holidays).

5.1.2 Prices

Tariffs can have many components. Energy based tariff components (c/kWh) can be simple static prices or be ToU dependent. Earlier, the ToU tariffs demanded a corresponding meter, but with new hourly meters arbitrary ToU’s can be used. There is quite an extensive set of ToU tariffs already in use, so the test bed must be very flexible to accommodate them all.

For example, a dynamic tariff/time series language in use for dynamic contract simulation purposes, for example to simulate a retailer’s tariff incomes and procurement expenditures, is presented in (Koreneff 2000). It allows for all kind of ToU tariffs as well as for spot price based tariffs and even all kind of combinations. It is highly preferable to have a similar high level language available for use in the test beds, so that new tariff structures are not left out just because they do not fit current static model conceptions.

As tariffs are have the potential to become more dynamic, if they do, so will the customer behaviour, especially if there are shiftable or curtailable loads involved. Test beds including energy storages and/or dynamic behaviour have to optimise the customer behaviour/load according to all costs: energy sale tariffs, distribution tariffs, taxes and VAT.

Capacity or peak load based tariff items need own algorithms. The determination of the invoiceable peak load/capacity is something where SG really is opening doors. International experiments (see Evens & Kärkkäinen 2009 for examples), and a good test bed might assist in creating even better and more rightful tariff designs.

5.1.3 Dynamic behaviour

If the test bed includes dynamic behaviour such as demand response, energy storages, and/or alternative sources, the decision process of the end-user (or an aggregator) should be simulated as closely as possible. This means having all cost items, such as both energy and network tariffs as well as taxes included. For example, if the end-user has an hourly changing spot based energy tariff, the spot price differences might be more decisive than the ToU distribution tariffs, so to estimate the dynamic load solely based on the distribution tariff would give misguiding results.

Dynamic behaviours should be estimated with respective separate models.

5.1.4 Using test beds

The main use of tariff test beds is to compare tariffs with each other. This can be done from several points of views, for example from the end-user or the network company’s views. New tariffs may be designed to steer end-user loads into more desired profiles, while keeping the costs equal for a non-reacting customer. The test bed can be used to determine the best new tariff for all relevant end-users or to calculate the effect on single users or user groups.

An important aspect is the estimation of the effect of the tariffs on the dynamic behaviour of end-users. How much do the loads change or switch from one time to another thanks to a given tariff?

5.2 KOPTI test bed

The KOPTI test bed is a test bed for the dynamic behaviour of end-users (Kekkonen 2010). It simulates the monetary flows of all actors while optimising the use of distributed energy resources (DER). For example, for the end-user it includes all the tariffs (distribution, energy) and taxes. The DER usage is calculated using a short run cost based linear optimisation model (KOPTI), where the point of view can be switched between electricity seller (e.g. aggregator) end-user, DSO and state (taxes).

5.2.1 The test set-up

The bed is tested using a simple test of an electric heated house with a constant heat demand and a small heat storage. The principle of the step responses to a step change of the price is shown in Fig 13. In the model, the heat storage has a small heat loss. The maximum power is restricted to two times the constant demand.

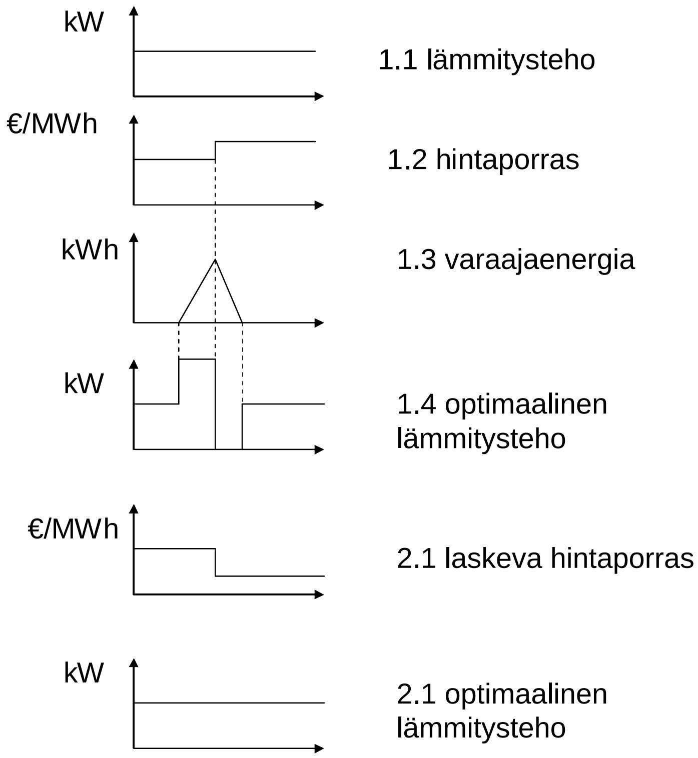

Fig 13. The test load used in the test bed. 1.1 is the heat demand (electric heating), 1.2 is the price curve with a step change, 1.3 is the energy content of the heat storage, 1.4 is the resulting optimal load. 2.1 shows how the optimal load (2.1 lower) reacts to a decreasing step change in the price (2.1 upper): it doesn't.

If the price rises, then the economically optimal solution is to load the heat storage just before and then to use it directly after. This is due to the small storage heat loss.

For the energy retail costs, a one price tariff, a ToU tariff and the Nord Pool spot price were used. Two different winter 2010/2011 weeks were used for the spot price, a peak price week and an ordinary week, see Fig 14. For the distribution costs, a one price tariff as well as a ToU tariff was used. The one price and the ToU tariffs (both energy and distribution) used in the tests are public[6].

[6] Public Savon Voima Oyj (retail) and Savon Voima Verkko Oy (distribution) tariffs in force 1.1.2011(used also for December 2010 calculations): Yleissähkö 3x35 A as one price tariff and Yösähkö 3x35 A as ToU tariff), http://www.savonvoima.fi/SiteCollectionDocuments/yksityisasiakkaat/Sahkonhinnat_010420111.pdf .

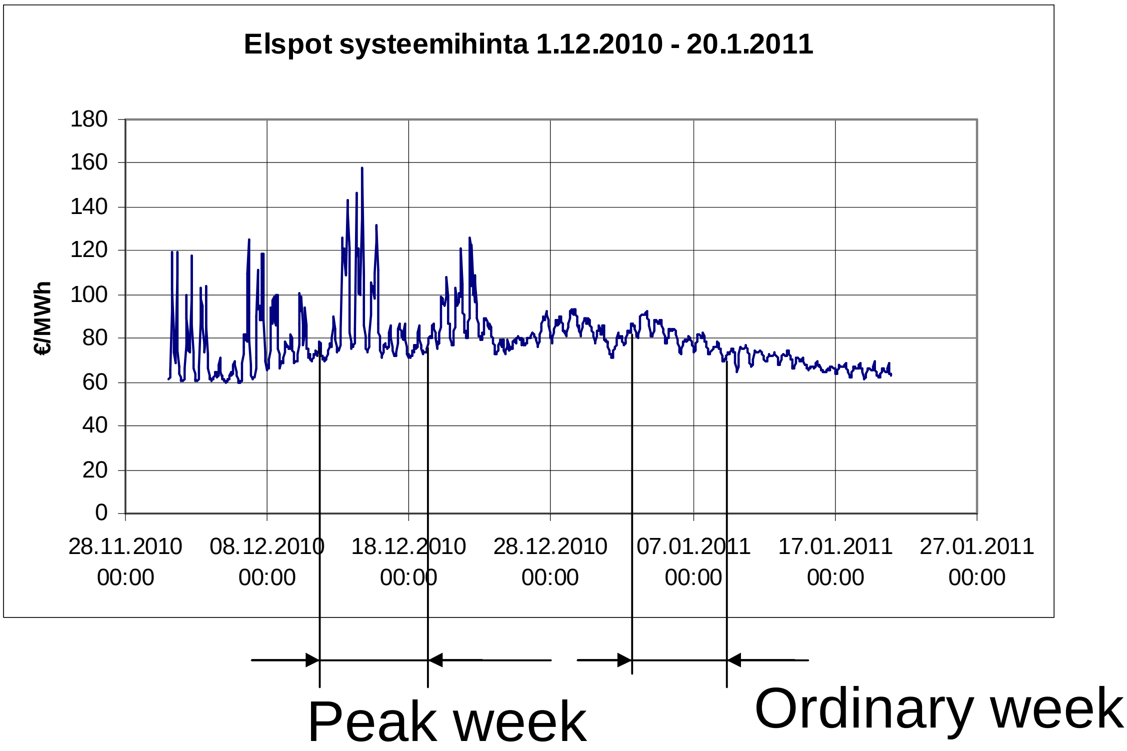

Fig 14. Using Nord Pool system prices, two spot price weeks were used in the tests, one a price peak week and the other an ordinary week from winter 2010/2011.

The weekly costs for the end-user with a constant and even load in the different cases are shown in Fig 15. For the energy retail, Nord Pool prices are higher than the one price tariff, which in turn is higher than the ToU tariff. For distribution, the ToU tariff is less expensive than the one price tariff. The fixed tariff items, for example monthly costs, are not included. The normal unshifted load would be larger during the day and smaller during the night, thus reducing the cost difference between the ToU and the one price tariffs. Most retail energy in Finland is bought through the Nord Pool spot market, so on average, the ToU should be more expensive, although this may vary year to year and from one energy retailer to another.

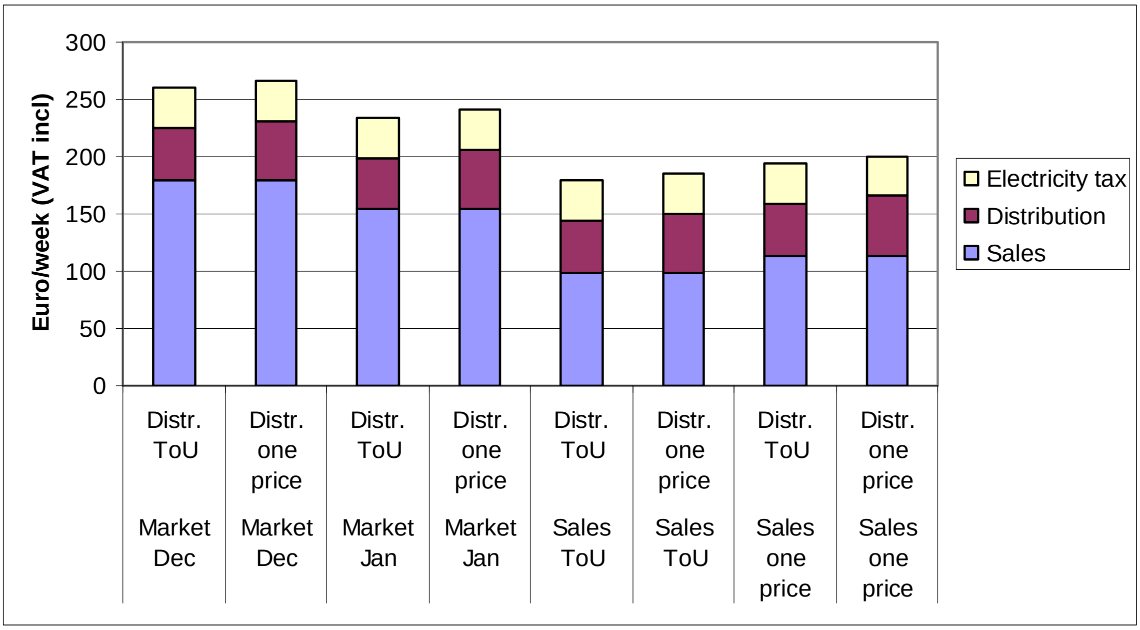

Fig 15. End-user costs for one week for different sales and distribution tariff combinations. Electricity tax and VAT are included, but fixed tariff items (€/month) are not. Market Dec is a peak price week in December 2010, Market Jan is an ordinary winter week in January 2011.

5.2.2 ToU tariff results

If the end-user load is optimised according to ToU tariffs for both energy and distribution, the resulting load is as is shown in Fig 16. The time-of-use tariffs have a significantly lower night-time price, which is why the heat storage is loaded up at that time. The loading takes place right before the end of the night-time price to minimize storage losses. Thus also the use of the stored heat takes place immediately.

The whole weekend follows the night-time prices, which is why the storage is not used during the weekend. There is no price difference to be utilised.

The resulting cost savings are shown in the summary table (Table 2). Cost savings for a customer are 7.20 €/week, all electricity cost items included, when compared to a constant load. This is the profit the heat storage and the load switching brings the end-user. Just looking at the distribution costs, the savings are 12 % (5.45 €/week), but it is good to remember that this is also an. earning loss to the DSO company. This loss of income is one of the problems with steering tariffs. If customers react to the tariffs, the DSO revenues decrease but the DSO costs do not (although new costs might be avoided). To be able to cover his invariant costs, the DSO must raise his tariffs, which might not be seen by the active end-user as a rewarding feedback for his efforts.

Fig 16. Optimised load when ToU tariffs are in place for both energy and distribution favouring night-time loads.

5.2.3 Spot price based results

If the end-user load is optimised according to the spot price, the results look like in Fig 17, which shows the load during the peak price week. The distribution tariff is a one price tariff. The heat storage is in more frequent use than in the case of ToU tariffs, being loaded nearly 20 times compared to 5 times in the previous case.

Cost savings are approximately 10 euro during the peak load week, but more interestingly, they are only 16 cents during the off-peak winter week. Cost increases due to the storage heat loss eat most of the modest energy sales tariff earnings.

A better comparison is to have a ToU distribution tariff instead of a one price tariff. The resulting load curve, see Fig 18, is quite similar to the one with a one price distribution tariff.

Cost savings for a customer are now roughly, all electricity cost items included, 15 €/week compared to a constant load for the peak load week. The saving percentage is low, as it is an expensive week, but even compared to the annual mean weekly cost, it is unimpressive.

Fig 17. Spot price from peak price week as energy tariff and a flat tariff for the distribution.

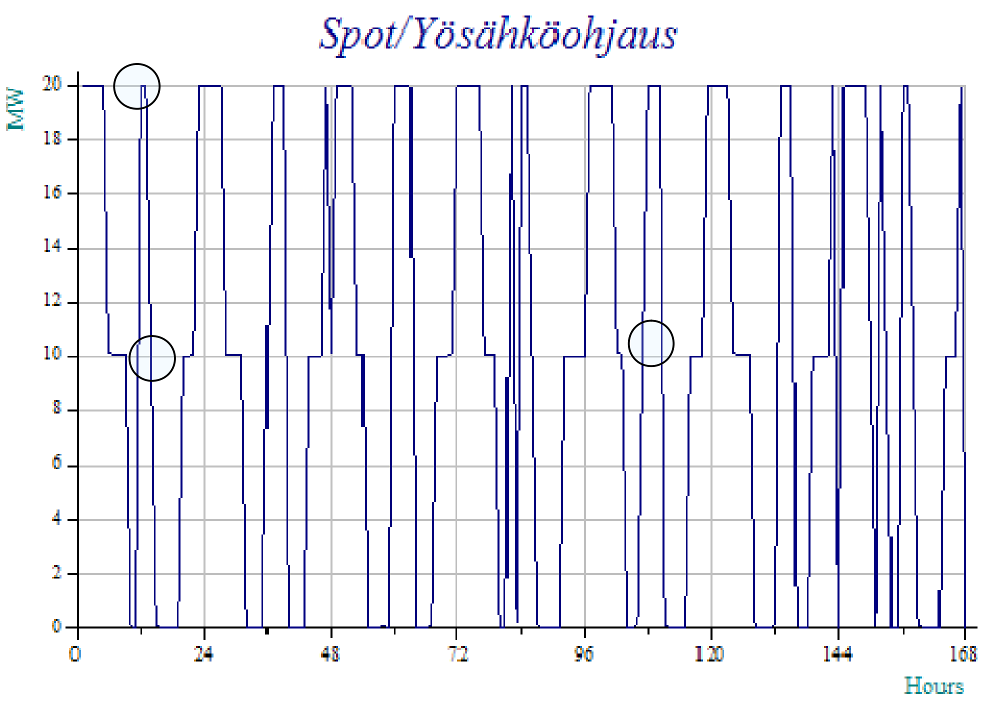

Fig 18. Spot price from peak price week as energy tariff and a ToU tariff for the distribution. The changes to Fig 17 are circled.

5.2.4 Test bed results summary

All the case results are shown in Table 2. The first two rows describe the situation where a retailer/aggregator is allowed to optimise the heat storage according to the market price, but the end-user pays the retailer according to a one price tariff. It shows the costs of the heat loss of the storage. It is the minimum compensation the retailer/aggregator has to compensate the customer with for the right to control the load/storage.

Table 2. The weekly savings for the end-user from load shifting under different sales and distribution tariffs. The savings are calculated as compared to a constant, non-steered load. Negative figures implicate losses, i.e. no savings.

Sales tariff	%	Change €	**Distr.tariff**	%	Change €	**El. taxes**	**SUM €**
One price (Dec*)	-1,7 %	-1,89 €	One price	-1,7 %	-0,86 €	-0,59	**-3,33**
One price (Jan*)	-0,6 %	-0,68 €	One price	-0,6 %	-0,30 €	-0,20	**-1,18**
Market price (Dec)	6,3 %	11,34 €	One price	-1,7 %	-0,86 €	-0,59	**9,90**
Market price (Dec)	6,1 %	10,99 €	ToU	10,8 %	4,88 €	-0,53	**15,34**
Market price (Jan)	0,4 %	0,66 €	One price	-0,6 %	-0,30 €	-0,20	**0,16**
Market price (Jan)	0,3 %	0,47 €	ToU	12,0 %	5,43 €	-0,28	**5,61**
ToU	2,0 %	2,01 €	ToU	12,0 %	5,45 €	-0,26	**7,20**

* load shifting of customer load is allowed for the seller who buys from the market (and earns 9.21 euros in Dec and 53 cents in January)

For demand side management to be profitable, it should benefit from both the energy sales tariff and from the distribution tariff. Without a ToU distribution tariff gain, the end-user profits are small from the load shifting. The heat losses from the storage eat away at the savings, so the worse the heat storage efficiency, the less profit for the end-user.

Even looking at market price based savings, they are significant during a peak price week, but unfortunately price fluctuation within a week are most of the time more like the normal January week, so savings will remain diminutive. Taking into account investments, management, telecom expenses, additional reporting, the business case for active demand side management would seem to have to rely on much steeper price differences than what these tariffs show and/or on additional benefits (balancing market with upfront capacity payment, emergency demand response, etc.). The future system benefits from demand side integration, as discussed in section 4.2.2, can be multifold.

One of the problems with load shifting tariffs is the loss of income for the utility, as already mentioned. Most tariff design based examples of demand side integration as presented in Evens & Kärkkäinen (2009) have as basis, that the tariff changes should be cost-neutral for passive end-users. This of course means that the network revenues will drop thanks to active end-users. If, and as, the network costs do not drop similarly, the utility will experience a revenue deficit, which has to be covered by price increases leading to a vicious circle. This might not be welcomed by active end-users who feel they have “done their share”.

6 Conclusions

The significance of varying electricity production from renewable energy sources is estimated to increase in the future. *Smart Grid* is a term used for a 21st century electricity network utilizing modern information technology. SG, of which several concepts are currently under research and development, is a part of the potential solutions for addressing the integration of often non-dispatchable RES electricity in energy systems. SG brings new options and needs for design and setting of network tariffs. The change brought by the new SG environment affects the use of electricity, elasticity of demand, mobile loads, large penetration of DG and energy storages etc.

The emerging options and requirements for transmission and distribution tariffs in the evolving environment of SG were studied in this report. Both a theoretical literature review of economics and modelling and simulations of the energy system and of tariff implications were carried out in the study.

6.1 Optimal network tariffs: guidelines from theory

In a liberalized electricity market, distribution and transmission of electricity are considered natural monopoly activities. According to theoretical review, approached from economics, marginal cost based pricing maximises the social welfare also in natural monopoly activities. That is, the “first best optimum” of any distribution or transmission company, from the social welfare point of view, can be said to be setting the price equal to the marginal costs.

The properties of natural monopolies, however, implicate that marginal cost principle cannot be directly applied in pricing and tariff design. In natural monopolies, the long-run average cost decreases as a function of production. Thus, if prices are equal to marginal costs, revenues of a producer fall short of total costs implicating financial losses, which are not generally acceptable for regulated companies.

In the light of economic theory, attractive methods to ensure cost recovery were introduced *(Ramsey pricing* and *optimal two-part tariffs)*, as well as several so called rolled-in pricing methods, which are currently widely used. Their drawback is their limited incentives in guiding market participants towards economic efficiency.

Locational Marginal Pricing (LMP) was discussed as a theoretically supportable option to include “difficulties” of transmission or distribution of electricity in prices. Thus, marginal costs of electricity system are assessed more comprehensively. However, determination of LMPs to co-optimize the network usage and generation calls for centralized calculation of dispatch schedules for generation units. The calculation takes into account market participants’ bids and physical properties of the network. Thus, LMP pricing seems to be applied in markets where system operation and market operation are relatively firmly integrated, different from the design of Nordic power market.

The implementation of theoretically attractive tariffs may be restricted by the fact that there are several companies and organizations involved. That is, in an unbundled industry, both regulated and deregulated actors exist, and transmission, distribution, generation and sales of electricity are not planned by one single institution.

Due to implementation issues and the set-up being not straightforward from economic theory point of view, design of, from all desired properties point of view, optimal tariffs seems to be impossible. Thus, trade-offs between tariff design objectives (*sustainability, economic efficiency, non-discrimination or equity, additivity, and transparency*) can be seen as practically unavoidable. In this respect, it is not surprising that a closer review of distribution and transmission pricing in European countries revealed differences in the practices of tariff design.

The trade-offs between tariff design objectives seem unavoidable also in the future, but the changing operation environment may alter the relative importance of objectives. SG presents a possibility and a wish for the end-user to take a more active role in electricity markets, as demand response will be really highly sought after. This justifies more dynamic, real-time varying components, cost-causality and incentives in pricing and tariffs. If DG and RES integration increases or decreases network congestion or losses, the importance of their management increases. One option for how to adapt the electricity system to a changing environment is to rely on market-based incentives. This would also call for inclusion of signals of short-term network costs (congestion, losses) in distribution tariff design to a greater extent.

6.2 Smart Grids, distributed energy resources, and tariffs

The introduction of Smart Grids brings along a multitude of new opportunities for the energy market. The automatic meter reading and two-way communications have the possibility to activate all end-users, not only the very large ones. How can the transmission and distribution networks benefit from the activeness of small end-users?

The user loads are and will experience significant changes in the following decades. Energy efficiency is targeted to improve, heat pumps will change the electricity usage for heating in electric and non-electric heated houses, distributed generation is expected to increase, and electric vehicles are on the coming.

Some load changes might increase the intraday flexibility of system significantly; for example, electric vehicles equipped with smart charging and vehicle-to-grid (V2G) properties show tremendous potential, but end-user heat storages should not be forgotten. This end-user flexibility is usable for all parties; for the distribution network to, among others, avoid raising line capacities, for the system operator as regulating or reserve capacity, and for the market as price elasticity and inexpensive regulating power. Whereas monopolistic systems could optimise the usage of the flexibility for the various purposes both in the short and the long run, a deregulated and unbundled power system has to, or at least should, use market mechanisms. With SG, information can be delivered to the end-user online and automatically from the market actors directly or through intermediaries such as aggregators. The delivered information can be control signals for various devices, giving the control (and part of the gains) of the load to the outside, but, on the other hand, the information can be delivered through direct price signals. In case of price signals, the end-user has to optimise his behaviour according to his minimum total costs, taking all the varying costs into account: taxes, seller tariffs, DSO tariffs, and why not in the future even TSO balance premiums etc.

In the future, the end-user or his representative (aggregator) will almost online receive various price signals and can then optimise the use of his devices, be it storages, DG, or loads. The price setting done by the individual interested parties (seller, DSO, and maybe even TSO in the future) will determine the behaviour. The tariffs will to some extent have to compete for the end-user DER, so tariff structures and levels are decisive. But in competing for the end-user DER it is good to remember than only the seller is purely operating in the deregulated market with all the risks associated with it and should have priority. However, the authors feel that market distortion of static ToU distribution tariffs is not significant compared to their potential benefits, which the Finnish experience can be seen as collaborating.

The distribution tariff prices should not be dynamic in the sense that they would decided on intra-daily, because this would place a too large a burden on the retail sellers The market side should have monopoly on price modifications on a timeframe of a couple of days up to the hour in question. Load shifting needed by the distribution companies should be bought from the sellers/aggregators or, if bought directly from the end-users, then the sellers should be compensated to their verified losses (e.g. increased balancing costs). Emergency reserves are an exception. Their route of command should be from the System operator to the TSO and from there further to the DSO’s.

6.3 Test bed experience

Tariff structures and levels need to be tested and verified. It will be more and more important to be able to assess the effect they have on distributed energy resources. This is best done in a versatile enough testing environment able to manage even complicated tariff structures, energy storages, DG etc.

A prototype test bed was put up. KOPTI test bed was used for testing the dynamic behaviour of end-users. It simulated the monetary flows of all actors while optimising the use of an end-user heat storage. The optimisation took place using different sales and distribution RTP and ToU tariffs. The savings for the end-user were pretty modest, but it is good to note, that without ToU distribution tariffs, the RTP generated end-user savings would be small even during normal winter weeks. A winter week having very high price peaks did result in noticeable savings, but even then savings were less than ten percent.

If a market-based demand response is desired, it is a necessity to have an adequate time resolution in the tariffs. That is, if the tariff is constant over a said time period, there are no incentives for end-customer to shift his load within that period. This applies not only to network tariffs but the totality consisting of energy and network tariffs.

On the whole, the authors feel that demand side integrating tariffs will be very valuable for the power system in the future. The increase of intermittent power production together with an ongoing phase-out of regulable capacity will result in heavily fluctuating power prices and costly new capacities, unless end-user distributed energy resources can be activated. For this to happen, both energy and distribution tariffs are needed as potential means to give incentives to the end-user. In practice, system-level benefits may result even though price signals are not coordinated. The end-user should be allowed to decide on his actions based on the tariffs.

6.4 Future research

Network tariffs have the unenviable duty to not disturb the market side. Most of the tariff design questions and ideas concern the sales tariffs, which can or should make the most of the DER available.

Network tariffs are of interest mainly in how they cooperate with the sales tariffs, which is something the test bed can answer. An expansion of the test bed and further tests will give valuable information to all market participants.

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