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Functional Objectives and a Technical Realisation of Interactive Customer Gateway (INCA)

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Abstract

In smart grids all the electricity end-users, even the small-scale customers play a more active role in the markets than traditionally. In the smart grids system many of the end-customers have small-scale electricity generation of their own. The rechargeable batteries of electric vehicles function as local energy storages and the load equipment is controlled based on versatile information without adverse effects.

This report focuses on the technical realisation of the interactive customer gateway (INCA). The topic is approached by determining the objectives for the system from the perspectives of the wholesale and the retail markets of electricity, the business related to power distribution and the end-customers' role in the system. The objectives are formulated to objective functions of optimisation tasks related with the control of the INCA. The constant, active and adaptive control of the customers' coupling interface enables enhancement of the energy efficiency and reduction of emissions of the whole society, while at the same time the end-customers' costs of energy use can be cut.

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1 Introduction

The basic concept of **interactive customer gateway** (INCA) was introduced to public already years ago (Järventausta 2008a). The INCA is a logical interface that aims on integrating together the business objectives of electricity market players and all end-users. (Kaipia 2010). This report presents the formulation of the business optimisation problems of electricity retailers, distribution system operators (DSOs) and the electricity end-users (the end-customers), and how to fit them together. A formulation of the electrical energy demand response related optimisation problem and a potential solution based on the utilization of INCA are illustrated. Furthermore, implementation of the INCA is considered including discussion of information exchange needs and introduction of a technical realisation.

The operation of the INCA is controlled by algorithms that in practise execute the optimisation. The actual optimisation tasks are shared between centralised information systems (external) and the distributed intelligence of each gateway (internal). Seamless co-operation of these physically separate parts and ability to adapt to the existing conditions is required. An efficiently operating interactive customer gateway can dramatically change the market and power system behaviour seen by the market players.

The INCA composes of active load appliances, building automation, active network components, widespread communications network, local control system, and information systems of external service providers (DSO, TSO, Energy retailer, Aggregator, etc.). Figure 1.1 present the concept of INCA. (Kaipia 2010)

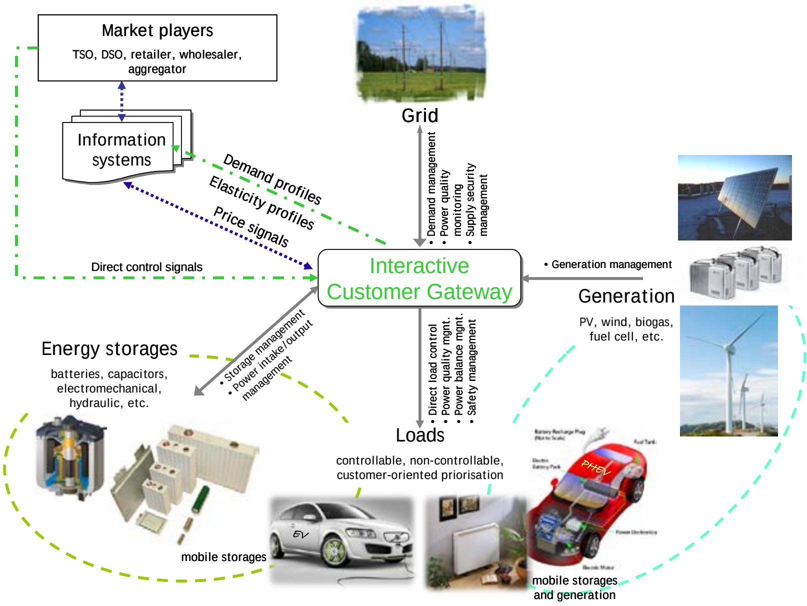

Figure 1.1. The concept of interactive customer gateway. (Kaipia 2010)

The gateway can contain controls for a single customer (e.g. residential household) or for a group of customers (e.g. apartment building, industrial complex). In this research the INCA concept is used as a basis for the development of a comprehensive energy usage optimisation model to be applied in the Green Campus environment.

The implementation of the Green Campus Smart Grid utilises the experience from the installations and technical solutions made for a LVDC (Low Voltage Direct Current) laboratory research platform at Lappeenranta University of Technology. (Nuutinen 2011, Makkonen 2010)

The goal of the implementation phase is to integrate smart grid elements in an existing customer-end low voltage network. The implementation work is divided into three main parts; interconnection of wind and solar generation (1), introduction of electric vehicles (EVs) and static battery energy storages as well as demand response (2), implementation of intelligent system control optimising the use of energy sources based on market situation, technical constraints and end-user needs. The GCSG system can optimise its internal consumption, interact with electric vehicles, accept versatile distributed generation units and operate in island when necessary. The basic concept and the units of the Green Campus Smart Grid are presented in former publication (Makkonen 2012).

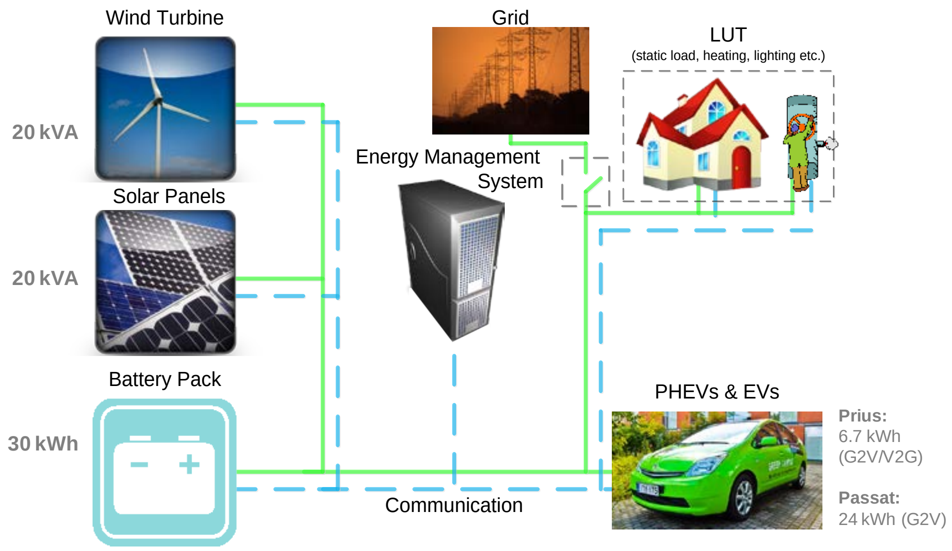

Figure 1.2. Basic concept of the Green Campus Smart Grid.

2 Market parties’ business planning and operation

The key target of electricity retailers and DSOs is to maximize their expected profits within the constraints set by the operational and market environment. Electricity end-user primary aim in turn is to minimize energy costs without the loss of comfort level. Thus, changes in the operational environment, such as the increasing amount of distributed energy resources (DER) including customer load controls, energy storages and distributed generation, affect different market parties operation in different ways. On the other hand, different market players operation also sets different type of constrains and requirements, for instance, for the development of operational, market and optimisation models.

Consequently, different market parties’ interests and needs have to be examined in detail before comprehensive optimisation model and algorithms can be developed. This chapter provides a basis for the further development of energy usage optimisation models based on the concept of INCA by presenting the key elements of electricity retailers and DSOs business planning, and considering customer's perspective and incentives in the electricity markets.

2.1 Planning of electricity retail business

The key target of an electricity retailer is to maximize the expected profits in the power markets. In addition, the retailer has to minimize risks in order to ensure the viability of the retail business. The maximisation of profits and the minimisation of risks are contradictory objectives, which have to be balanced appropriately. (Valtonen, 2012)

In the current operational and market environment profits of the electricity retail business are fairly limited, although risks are considerably high. The main tool for the minimisation of risks is long-term (and mid-term) hedging by using financial instruments and bilateral contracts. In addition, in a long term, the setting of retail sales price has high impact on the retailer's profits.

In a general level the planning of electricity retail business can be divided into long-term and short-term planning. Although the long-term planning provides basis for the profitable retail business, it does not ensure the viability of the retail business. In addition to long-term planning the retailer has to be able to operate based on the changing market situations in a short-term. Figure 2.1 illustrates the segmentation of electricity retailer business into long-term and short-term planning in the Nordic markets.

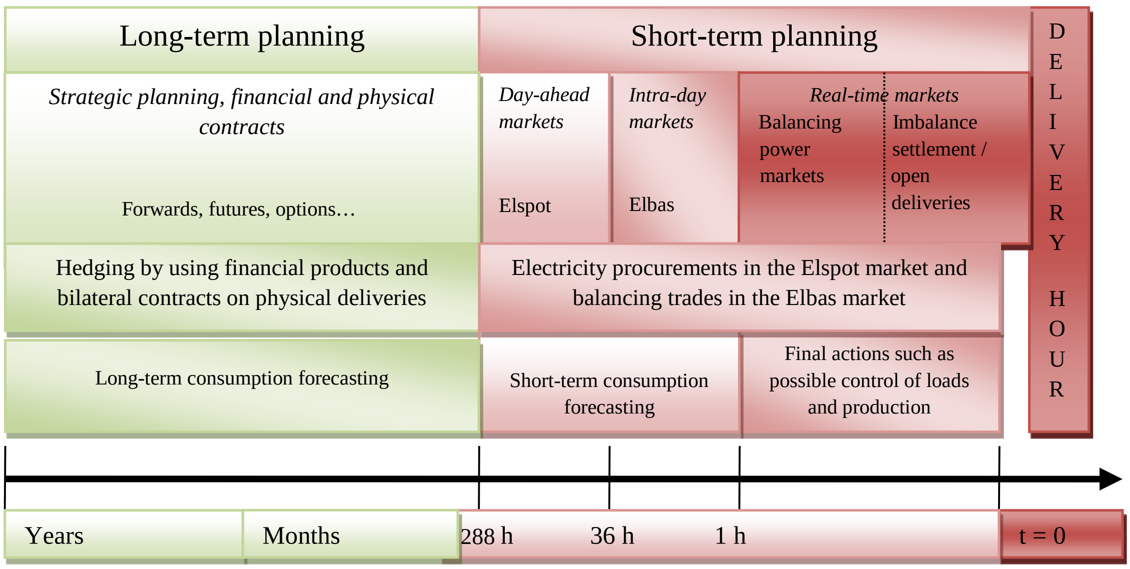

Figure 2.1. The planning of retail business in Nordic electricity markets (Valtonen 2012b)

The long-term planning is also known as strategic planning. One of its main objectives is to ensure fixed purchase price for most of the retailer's electricity procurements. In practice, electricity retailers can hedge in a long term by making physical electricity procurements in the OTC market (Over-The-Counter) or using financial products provided by the financial market. The hedging level should be set carefully, because over-hedging reduces expected profits and too low hedge ratio exposes the retailer to high risks. The short-term planning in turn covers the management of electricity procurements in the day-ahead (Elspot), intra-day (Elbas) and balancing power markets, and the possible utilization of controllable DER including control of loads, small-scale production and energy storages. (Valtonen 2012 b)

One of the basic problems in the electricity procurement planning is that customers' future electricity consumption can be forecasted only with limited accuracy. Therefore, there is almost always some difference between a retailer's forecasted and actual electricity consumption. The difference between secured electricity procurements in advance (contractual position) and expected electricity sales in the retail markets (tariff-based sales) form an *open position* for a retailer. The existence of open position together with the market price risk poses a subsequent cost risk for the retailer. Consequently, the short-term profit optimisation, which includes the management and fulfilling of open position prior to the delivery, has an important role in the retail business. (Valtonen 2012 b)

2.1.1 *Practical example on retailer's electricity procurement planning*

In practice, an electricity retailer has to purchase the actual energy in the physical power markets, although it would have hedged by using financial products in a long term. In addition, the physical power markets provide an opportunity to make balancing trades when the delivery hour approaches. Balancing trades can be made in the Elbas market until one hour prior to the moment of delivery. After that, the retailer cannot anymore trade energy in the short-term markets, and thus, the remaining open position forms a *power imbalance* (difference between electricity procurement/production and consumption/sales) for the retailer. This imbalance has to be neutralized by the means of imbalance (regulating) power. In practice, the "trading of imbalance power", is done via imbalance settlement procedure, in which the open deliveries between the market parties will be settled. (Valtonen 2012 b)

The level and volatility of imbalance power prices can be rather high compared to spot prices. Thus, in order to minimize the risk related to power imbalance and its neutralization by the means of imbalance power, the retailer should aim to minimize the size of its open position by making balancing trades in the short-term markets. This type of risk avoiding profit optimisation strategy is particularly recommendable in the price volatile markets, where high variations in electricity prices exposes retailers to high risks. Figure 2.2 presents an example which demonstrates the above-described risk avoiding electricity procurement strategy in a long term.

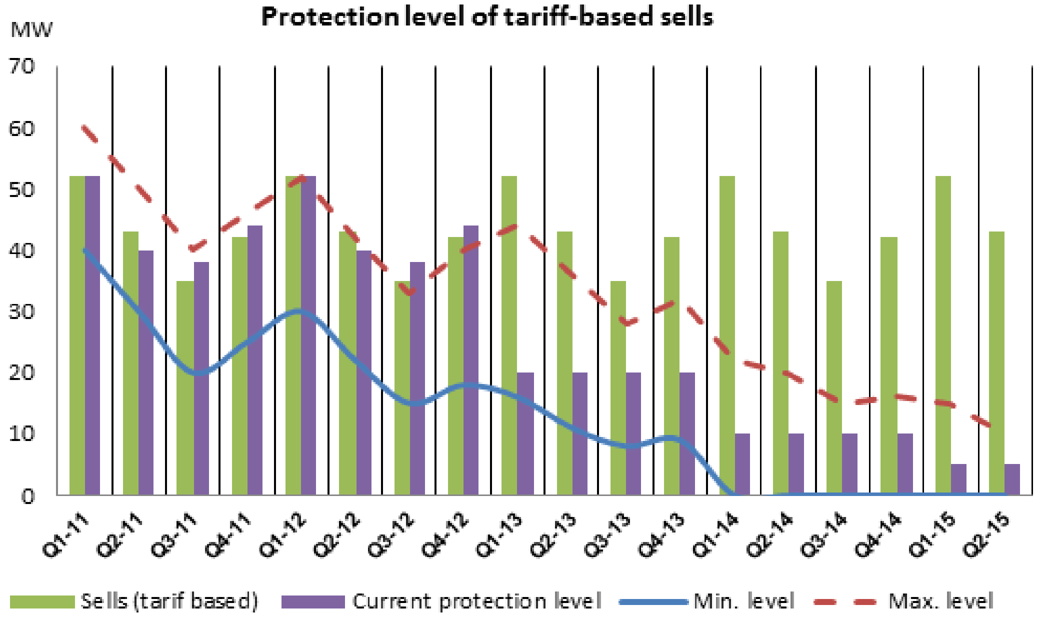

Figure 2.2. Hedging of retailer's electricity procurements in a long term (Valtonen 2012 b)

Figure 2.2 shows that the size of the retailer's open position is aimed to set between the minimum and maximum limits of the retailer's hedged electricity procurements, which is adjusted according to the tariff-based electricity sales. The red dashed line in Figure 2.1 presents the maximum hedging level, and blue line the minimum hedging level.

This risk avoiding hedging strategy aims to decrease the size of open position when the delivery hour approaches. In other words, the longer the time span between the present moment and the delivery hour is, the less hedged procurements are made. This ensures that the risk caused by the variation in electricity prices can be kept within permissible limits without excluding the possibility to achieve savings in case of lowering electricity prices.

2.1.2 *Profit optimisation problem formulation*

To address the electricity retailer's profit optimisation problem in the Nordic electricity markets and to simplify the examination some basic assumptions are needed. First, it is assumed that the retailer has made long term hedging in order establish a contractual position, which decreases the retailer's risks. It is also assumed that the retailer sells electricity to its customers using fixed rates-based tariffs, and trades electricity in the Nordic spot markets, and if needed, through the imbalance settlement.

It can be also assumed that retailers operating in the Nordic markets do not have significant market power, and can be considered as price takers. In other words, it is assumed the retailer cannot impact on electricity prices by its own bidding actions, and other market participants have no significant impact, through bidding actions or other operations, on the retailer in question.

An electricity retailer's profits on the power markets depends on the energy sold on the retail markets E_{sell}, the electricity retail sales price ρ_{sell}, energy purchased on the wholesale markets $E_{buy,}$ and the price of purchased electricity on the wholesale markets ρ_{buy}. Thus, the maximum profits at the time interval t = 0…T are:

$$Max \int_0^T Profits(t)dt = Max \int_0^T \left(\rho_{sell}(t) * E_{sell}(t) - \rho_{buy}(t) * E_{buy}(t)\right) dt. \quad (1)$$

To simplify the problem formulation, it is assumed that the retailer has made long-term hedging using financial instruments and purchases the actual physical energy on the spot markets. Because the retailer has secured fixed price for most of its electricity procurements and sales in a long term, the retailer's operation in the short-term markets determines the retailer's final profits. Consequently, the retailer's profit optimisation problem can be simplified now to include only retailer's short-term profit optimisation. In a short-term, the retailer's maximum profits at the time interval 0…T can be expressed as

$$Max \int_0^T Profits(t)dt = Max \int_0^T \begin{pmatrix} \rho_{sell}(t) * E_{sell}(t) - \rho_{spot}(t) * E_{spot}(t) - \\ \rho_{elbas}(t) * E_{elbas}(t) - \rho_{reg}(t) * E_{reg}(t) \end{pmatrix} dt, \quad (2)$$

where ρ_{spot} is the Elspot price, ρ_{elbas} the Elbas price, ρ_{reg} the price of the imbalance power including balance power fees, E_{spot} energy traded in the Elspot market, E_{elbas} energy traded in the Elbas market, and E_{reg} the amount of traded imbalance power. (Valtonen 2013)

In the short-term markets the retailer cannot influence the amount or price of the sold energy by its own actions and thus the parameters ρ_{sell} and E_{sell} can be regarded as exogenous. Thus, the retailer's profit optimisation problem can be turned into the form of an electricity procurement cost minimisation problem, expressed by the equation

$$C_{min} = \int_0^T \begin{pmatrix} (\rho_{spot}(t) * E_{spot}(t) + \rho_{elbas}(t) * E_{elbas}(t) + \\ \rho_{red}(t) * E_{reg}(t) \end{pmatrix} dt, \quad (3)$$

where C_{min} is the retailer's minimum electricity procurement costs. (Valtonen 2013)

In the current operational environment retailer typically have no cost-efficient opportunities to utilize DER as a part of their profit optimisation. However, transition towards smart grid environment and the development interactive customer gateway can enable electricity retailers to utilize controllable DER (Distributed Energy Resources) as a part their profit optimisation and management of electricity procurements. The electricity retailer profit optimisation problem in the smart grid environment, where INCA concept provides a base for utilization of DER as a part of retailer profit optimisation, can be expressed as an electricity procurement cost minimisation problem by the equation:

$$C_{min.} = min \int_o^T \begin{pmatrix} (\rho_{spot}(t) * E_{spot}(t) + \rho_{elbas}(t) * E_{elbas}(t) + \\ \rho_{reg}(t) * E_{reg}(t) + \rho_{DER}(t) * E_{DER}(t) \end{pmatrix}. \quad (4)$$

where ρ_{DER} is the DER utilization cost and E_{DER} the amount of energy controlled by utilization of DER. E_{DER} in turn consists of E_{al}, E_{ag} and E_{es}, which present respectively the energy controlled by using active (controllable) loads, energy controlled by using active (controllable) generation, and energy controlled by using energy storages. Thus, the retailer's minimum electricity procurement costs can be expressed in the form:

$$C_{min} = min \int_0^T \begin{pmatrix} \rho_{spot}(t) * E_{spot}(t) + \rho_{elbas}(t) * E_{elbas}(t) + \rho_{reg}(t) * E_{reg}(t) \\ +\rho_{ag}(t) * E_{ag}(t) + \rho_{al}(t) * E_{al}(t) + \rho_{es}(t) * E_{es}(t), \end{pmatrix} \quad (5)$$

where ρ_{ag} is the utilization cost of active generation, ρ_{al} the utilization cost of active loads, and ρ_{es} the utilization cost of energy storages. (Valtonen 2013)

2.1.3 *Constrains for operation*

The retailer has also some constrains, which set limitations for the operation. However, most of these do not set very strict limitations for retailer's operation in. The main constrains for the retailer operation in a short term markets forms the load obligation, which oblige retailers to provide customers with the energy needed to cover their consumption (loads), and limitations set by the markets and system operator. Relating to the retailer's load obligation and management of power balance Fingrid Oyj, the Finnish System Operator (SO), obliges that the market parties has to plan and control their electricity procurements in a way that the power imbalance can be maintained at an appropriate level with respect to the extent of the operation of the party (Fingrid 2013).

In addition, the trading rules of spot markets set some limitations for retailer's operation. Most important includes the trading horizons and slots, within which the retailer have to operate. Table 2.1 present the limitations set by the spot and balancing power market for retailers operation.

Table 2.1. Limitations set by the short-term market for retailers operation. (Valtonen 2012 b)

	Elspot	Elbas	Balancing power markets
Trading period	Trading horizon: 12-36 hours ahead for the next day 24 hour period. Gate Closure 12:00 (CET-time)	2 hours after Elspot and 1 hour prior to the delivery	Binding production plans at least 45 minutes prior to the beginning of usage hour
Contract size	Trade Lot: 0,1 MW Min. Tick Size: Euro 0.1/MWh	Trade lot: 1 MW Min. tick size: Euro 0.1/MWh	Balancing power: Minimum capacity requirement of 10 MW Fast disturbance reserve: Minimum capacity requirement of 15 MW, minimum availability for use 7000 h/a and 3 h on non-stop
Order types	1. Hourly Orders 2. Flexible Hourly Offers 3. Block Orders (Volume Limit: 500 MW)	1. Fill: matching may be effected either for the full volume or for a part of the volume. Any remaining volume shall remain valid with the ranking of the original order.	Actual consumption is determined through imbalance settlement procedure. Production: Fingrid submits the regulation order when needed. Balancing power and fast disturbance reserves have to be

		2. All-or-Nothing: matching may only be effected for the full volume.	activated on full power in 15 minutes. The power changes have to be verified in real-time.

2.1.4 *DER as part of the retailer's profit optimisation*

In the current operational and market environment retailers can typically manage their electricity procurements (and open positions) in a short-term only by making balancing trades in the spot markets. However, the development of interactive customer gateway and the move from traditional passive distribution networks to active smart grids can provide new tools for this task. In particular, the ability to control customers' loads can provide cost-effective alternative for balancing trades in the spot markets. In addition, the increasing amount of small-scale distributed generation and energy storages will have increasingly important role in the planning and management of retailers' electricity procurements.

From the perspective of electricity retailers the ability to utilize controllable DER, and in particular load control, as a part of the retail business provides new opportunities to hedge against risks and operate more flexible based on the changing market situations. On the other hand, without proper planning DER controls can also increase retailer's risks, for instance as a result of unexpected variations in electricity consumption/production. Particularly interesting from the perspective of electricity retailer is the possibility to use controllable DER to hedge against price variations. In the best case, an ability to utilize DER controls as a part of retailer's profit optimisation could permit retailers' to hedge against price variations, or even benefit from price fluctuations, and provide considerable saving potential in the long run.

2.2 DSO's profit optimisation problem

Profit optimisation problem are basically profit maximisation and cost minimisation tasks. Those optimisations can be done also at the same time. Electricity distribution business is regulated by Energy Market Authority (EMA) in Finland and EMA set limits for moderate electricity distribution profit. On the other hand, DSO's duty is to transmit electricity with reliability and moderate prices. Consequently, it is reasonable to research DSO's business cost minimisation opportunities. The aims in DSOs' business and load control optimisation tasks are the same; minimisation of electricity distribution costs. This chapter presents how electricity distribution costs consist, how cost minimisation can be done at the moment and how load control based cost optimisation could be reasonable done in the future.

2.2.1 *Background of DSO's business optimisation*

The running costs of the DSO, such as operation, maintenance and fault reparation, are depending on the total length of the network and operational environment. More than half of the DSO costs are capital costs, which include investment and financing. Those costs are depending on electrical power in the network. Fig. 2.3 presents typical cost structure of the DSO. Network losses are only energy based cost factor. The losses are divided on the network losses and transformer losses. In turn, transformer losses can be divided load –and no-load losses. Only no-load losses of transformers are not dependent on the power in the electricity distribution network. Hence, energy based costs cover less than 6 % of total DSOs costs. Metering and billing, and partly administrative costs are, in turn, depending on number of customers. Electricity distribution network costs are mainly dependent on power. (Partanen 2012)

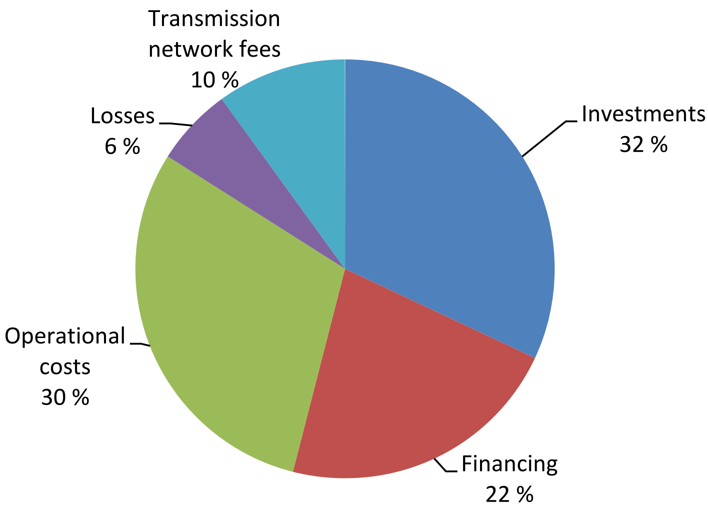

Figure 2.3. DSO's cost structure consists of fixed and power based costs. (Partanen 2012)

Network components of electricity distribution, such as conductors and transformers, are dimensioned based on power in the electricity network. Electrical power in distribution networks is dependent on powers of individual customers and peak powers of larger scale customer groups (transformer district, feeder, and substation). (Partanen 2012)

1.1.1 DSOs' business optimisation at the present

DSOs' business optimisation sets two types of boundaries: economical and technical limitations. Economical limitations in electricity distribution business are regulated by Energy Market Authority (EMA). Consequently, DSOs' business optimisation is basically based on cost savings at the present.

The company specific maximum allowed profit defines the capital based limit for the profit of a DSO. The EMA defines annually the reasonable rate of return for the capital tied-up to the distribution network business by calculating the weighted average cost of capital (WACC). The percentage is the same for all DSOs. The capital is divided into equity and liability and adjusted to describe the capital truly tied-up to the distribution business. The company specific allowed profit is defined as the product of the WACC and the sum of the present value of the DSO's network equity and the adjusted other capital tied-up to the distribution business, as presented in equation (6) (EMA 2011)

$$P_{all} = WACC \cdot C, \tag{6}$$

where P_{all} is the maximum allowed profit [€], *WACC* is the Weighted Average Cost of Capital percentage [%], and *C* is the sum of adjusted equity and adjusted liability tied-up to the distribution business [€]

The actual annual profit of a DSO is adjusted based on a particular rules starting from backward calculation of the turnover of the distribution business. For each DSO, the EMA compares the calculated allowed profit with the adjusted realised profit gathered with the distribution fees. The comparison is not made yearly basis but by calculating the sum of annual allowed and adjusted realised profits over the regulation period (at the moment over 4 years). The sum of adjusted realised profits over the regulation period cannot exceed the sum of allowed profits. (EMA 2011) The DSO can maximise the actual profit by increasing the allowed profit or by decreasing the adjusted realised profit. The methods are interconnected. In long-term, the profit maximisation is optimisation of the combination of increasing the allowed profit and decreasing the expenditures affecting the adjusted profit. In short-term, the actual profit can be maximised within the boundaries given by the allowed profit by influencing only the adjusted realised profit. In simplified case, it could be said that the long-term profit depends on the investments and the short-term profit of the operational costs.

In the short-term, the profit can be maximised mainly by minimising the operational expenses. The short-term profit maximisation is then actually in all cases a cost minimisation task that is bounded by the constraints such as supply availability and security as well as voltage quality. Furthermore, a DSO can promote energy saving, but cannot force the customers to reduce their energy consumption, so in this case also the total energy flow over a time period also set limits for the minimisation of the operational expenses. Even though, the goal in the short-term profit maximisation is to maximise the annual profits, the actual maximisation period – or in this case the cost minimisation period – has to be considerably shorter. Thus, the considered time period in short-term optimisation is for instance a week (168 h). Thus the objective function for short-term cost minimisation can be formulated as follows,

$$F_{short} = \min C_{\mathrm{ope}} = \min \int_0^T (C_{\mathrm{loss}}(t) + C_{\mathrm{outage}}(t))dt \, , \tag{7}$$

where C_{ope} is the operational expenses over a study period *T* (i.e. 168 h), $C_{\mathrm{loss}}(t)$ is the cost of network losses for hour *t*, and $C_{\mathrm{outage}}(t)$ the costs due to outages including the customer interruption costs (CIC) or cost of energy not supplied (CENS) and fault repair costs

In the long-term, the allowed profit can be raised by increasing the capital and its present value with network investments. Furthermore, the development of the operational expenses and the supply quality as a result of the network investments and other enhancements of operation enable raise of the actual profit in long-term. In the long-term optimisation, the time horizon is typically decades (e.g. 30-50 years). Because both the value of equity and the costs of operating the distribution system influence on long-term and are interconnected, the long-term profit maximisation task can be formulated as the total cost minimisation function, as presented in the equation (8). (Belonovoga 2011, Lakervi 1998) In this case, the objective function comprises both (6) and (7). The boundary conditions are the same as in the case of short-term optimisation added with constraints related with the technical capacity of network structures, such as short-circuit and load current capacities and electric safety.

$$F_{long} = \min C_{\mathrm{tot}} = \min \int_0^T (C_{\mathrm{inv}}(t) + C_{\mathrm{loss}}(t) + C_{\mathrm{outage}}(t) + C_{\mathrm{maint}}(t))dt \quad (8)$$

where C_{tot} is the total costs of the distribution system within optimisation period T (i.e. 40 a), $C_{\mathrm{inv}}(t)$ is the annual investment costs for year t, $C_{\mathrm{loss}}(t)$ is the cost of network losses for year t, and $C_{\mathrm{outage}}(t)$ the annual costs due to outages including the customer interruption costs (CIC) or cost of energy not supplied (CENS) and fault repair costs. Furthermore, investment costs comprise of replacement investments and investments to new network entities.

When considering both long and short-term profit maximisation, the ability to reduce peak power demand or prevent growth of peak loads is preferable. The ability to control peak power demand enables efficient control of the network losses and the need of installed capacity. The latter affects directly to the dimensioning of new installations and to the needs of strengthen the network during renovation, and thus, to the level of investment costs. Furthermore, the quadratic dependency of the network losses from the power demand and the coincidence of demand and price peaks results high dependency of the cost of losses from the magnitude and timing of the peak power demand.

Permanent savings as a result of the reduction of the peak power demand and sifting of peaks requires constant load controlling, either realised as market controlled voluntary demand response or with direct control signals. Clear incentives and economic benefits for the customers are needed in both cases. At the moment DSOs do not have efficient methods to provide constant load control incentives for customers as rather high economic benefits are expected. Hence, only traditional two-time (day/night) tariffs are offered for customers nowadays.

2.2.2 *Load control optimisation potential from the perspective of DSO in future*

From the perspective of different market parties, electricity distribution tariffs would need reform in Finland. DSO's aim in distribution pricing is the electricity distribution tariff structure, which is cost-reflective and motivates customers to shift electricity consumption to optimal time from the perspective of distribution network. In theory the best situation would be, if customers' power demand would be the flattest possible. Then the installed network capacity would be most efficiently exploited.

The current distribution tariffs (main fuse rating based fixed fee + energy fee) do not include many incentives to minimize peak power demand. Furthermore the cost-reflectiveness of existing tariffs is also difficult to trace. Development of distribution tariffs towards more power demand related pricing instead of existing energy related pricing could provide clear incentives for customers. Furthermore, the power demand based tariffs would reflect well the actual short and long-term costs of the distribution business. For instance, pricing based on peak power demand of an hour would motivate customers to optimize their electricity usage to be less peaking. This would bring savings both for the customer and DSO.

It would be remarkable benefit from the DSO's point of view, if every customer would have a certain power limitation for their electricity usage – kind of a bandwidth limiter. This could prevent overloading situations in the network and would improve the predictability of power demand. Load control or band width limitation is a potential method to decrease and prevent overloading of network equipment. Furthermore, from DSO perspective the available bandwidth is dependent from the state of the network and overall loading conditions. In the scenario of dynamic bandwidth limitation, the customer would have agreed on some nominal bandwidth with the DSO. In emergency situations and in exchange of agreed compensation the DSO could alter the bandwidth within agreed limitations. In practice, DSO would control customers' loads in the particular network area. Load controlling requires to taking into account reliability of electricity distribution and customers' comfort of living, which might disturb electricity distribution to customers. Consequently, DSOs should provide compensations from disturbing load controlling.

An electricity distribution tariff scheme, power band pricing (PBP), could be the solution to control the loads from the DSO's point of view (Partanen 2012). Customers would subscribe distribution power capacity from the DSO and pay the fixed electricity distribution charge monthly. PBP pricing scheme could provide incentives to customers for achieving economic benefits in electricity distribution charges. PBP could also decrease customers' power demand at the same. PBP would not cause conflict of interests between retail tariffs. It could be a solution to perform load controlling from the perspective of DSO.

2.3 Customer's energy cost minimisation problem

The main customer's driver for participating in the load control is minimizing electricity payment. In Finland, electricity bill comes to a customer separately from the retailer and the DSO. Therefore, payment minimisation task should be considered from both retailer's and DSO's perspective.

2.3.1 *Customer's energy cost minimisation at the present time*

At the present customer's electricity fees consist of retail and distribution charges. Electricity distribution fees forms of main fuse based fixed fee and energy fee. If customer's fuse size is the lowest possible, only energy based savings can be achieved. Whether customer's fuse size is over dimensioned, then could be decreased main fuse size and also fixed fees.

Retail pricing consists of energy based fee and fixed fee. Customer cannot effect on fixed fee typically. Consequently, customers can influence only their energy based fees, which are normally priced c/kWh.

Finally, it is concluded that customer's energy cost can be minimized by decreasing energy consumption at the present time. The smaller is energy consumption, the smaller is electricity costs.

2.3.2 *Customer's energy cost minimisation in the future*

In future, in the retailer's tariff the energy component is going to be more dominant, while in the DSO's tariff structure the power component is going to have a higher weight. This leads to the fact that the customer should focus on energy cost minimisation to minimize the payments to the retailer and on power band minimisation for the DSO payments.

In case of power-based distribution network tariff structure, customer is interested to have an optimal size of power band. This means that the maximum power level of the annual load curve should be minimized within the following conditions:

1. The ordered power band should be high enough so that the comfort of customer is maintained
2. The power band should be as low as possible to minimize the payments from customer to DSO
3. The ordered power band should be high enough to provide the retailer with enough of power capacity for load control activities (energy shifting from high to low price hours).

Since the retailer is assumed to be the decision maker in the load control scheduling, the power band should be taken into account by the retailer when carrying out market-based load control. Therefore, the overall minimisation of electricity payments for a single customer can be turned into market-based load control optimisation within the end user's comfort and power band constraints.

On the single customer level the optimisation problem consists of energy cost minimisation and at the same time maintaining the customer's comfort. This represents a multi-objective optimisation task, in which two objectives are conflicting with each other. The same optimisation problem has been already analysed on the building level, using multi-objective optimisation approach (Rui Yang, 2011), (Jun-young Kwak, 2012). Yet, on the single customer level it is a challenging task to define the customer's comfort level due to a large variation of customer types, behaviour, living habits. The research task is also challenging owing to different housing types, heating methods, the dependence of the residential consumption on weather conditions and duration of daylight. Load control actions can include, for instance shifting the electricity consumption from high spot price to low spot price hours. However, the optimisation principle is simple and can be expressed through the following equation (9).

$$E_{\text{savings}} = \max \int_{0}^{\text{T}} (E_{\text{contr}}(t_1) \cdot p(t_1) - E_{\text{payback}}(t_2) \cdot p(t_2) \text{d}t, \quad (9)$$

where E_{savings} is the energy cost savings [€] during a period T, $E_{\text{contr}}(t_1)$ is the controllable energy [MWh] during the hour t_1, $E_{\text{payback}}(t_2)$ is the recovered payback energy [MWh] at the hour t_2, $p(t_1)$ is the price [€/MWh] at hour t_1 on the electricity spot market, $p(t_2)$ is the price [€/MWh] at hour t_2 on the electricity spot market, and t_2 - t_1 is the duration of disconnection in hours.

The maximisation is done within the constraints:

1. Customer's comfort level maintained
2. Power band not exceeded

In order to solve optimisation problem and obtain the optimum combination of load control events for different customer types, it is necessary to know the following information for a single customer:

1. Estimation of the amount of load that can be disconnected, at every hour of the day
2. Estimation about possible duration of disconnection. In other words, for how many hours the load can be shifted without that customer notices discomfort (indoor temperature variations within allowed boundaries)

Customers' electricity consumption may vary a lot, and that is the reason why every customer's electricity cost minimisation has to be done separately. The most efficient principle might be, if is chosen the lowest possible distribution tariff and then is minimized energy consumption.

3 Multi-objective problem setting

The final control model should consider all market parties' interests and enable optimal use of DER without any significant conflicts of interests between the market parties. Figure 3.1 presents an example of comprehensive model which considers different market parties interests.

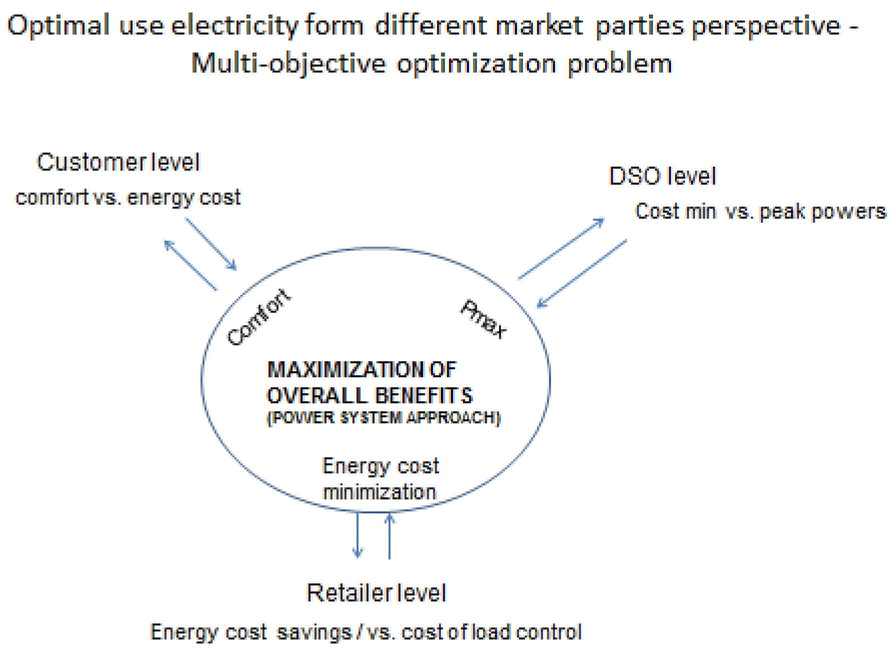

Figure 3.1. An example of model which considers different market parties interests

A basic problem in the development of a comprehensive model is that in practice different market parties may have different needs for DER controls at the same time, which creates conflict of interest between the market parties. For instance, if a DSO controls customers' loads in order to limit the peak powers, it can increase retailer's power imbalance, and result in considerable extra costs for the retailer. Thus, the market parties' co-operation and information exchange has a critical role in the model.

In practice, it is not possible to use available DER according to all market parties' interests and some compromises have to be done. The power system point of view sets the most critical conditions for the use DER, because the operation of the power system and the security of electricity supply should not be jeopardized in any circumstances. Thus, the maximisation of overall benefits is done within the limits set by the power system.

In addition to constrains set by the security of supply and the power system, the customers' comfort set its own limitations for the use DER. At the end, the customer should have an opportunity to make the final decision how he/she uses the appliances and consumes the energy. Therefore, in the introduced model the customer chooses which devices it allows to be controlled, and within which limits. In addition, the customer should get compensation or have some other incentives to allow some other market party to control its loads. In practice this problem can be solved for instance by using a pricing model, such as power band pricing, which provides adequate incentives for the customer.

3.1 Role of centralised and distributed decision making

A number of arguments support the model, in which the electricity retailer, or another corresponding market player, for example, an aggregator, is the party responsible for the execution of DER controls. Such a model would be compatible with the supplier-centric market model with mandatory combined billing which is widely-used in Europe. From the viewpoint of liberalized electricity markets, customer load control should be market-orientated rather than limited to local DSOs. In addition, retailers, who operate in the electricity markets and supply customers with the energy needed, typically have the best ability to explore and utilize the business potential of DER controls. Moreover, if some other market party, such as the local DSO, would control the loads of the customers of a retailer based on its own interests, the retailer's power balance between electricity procurements/production and consumption/sales will be disrupted. Therefore, in this model the maximisation of overall benefits using DER controls is done by an electricity retailer (or aggregator), which has the best ability to execute market-based DER controls and utilize the potential provided by DER.

In the proposed model, the use of DER is optimized by the retailer within constrains set by the customer and DSO. At the moment, the model is built in a way that the DSO can use load control only in critical situation in order to secure the security of supply. In the future, however, the model will be developed so that the power band pricing can be applied for the customer. In other words, in the future, the customer's loads can be controlled so that the customer's peak powers are maintained below the level set by the power band.

An electricity retailer can control customer's loads, and if possible energy storages and/or generation, based on its short-term profit optimisation principles and/or customer's energy cost minimisation needs principles and within the limits set by the customer. The limitations set by the customer can be taken into account by setting control limits and priorities for the use of customer's controllable loads, energy storages and generation. The customer can choose the loads which it allows to control, and set those into priority order based on its comfort or other needs.

In practice, many variables have impact on the benefits provided by the control of DER and principles based on which DER controls should be done. For instance, if the retailer sells energy to customer using a spot-price-based tariff, the customer has incentive to shift energy consumption to the lowest spot price hours. However, if energy is sold to customer based on fixed price tariff, the customer does not have incentive shift the energy consumption. The retailer's incentives to control the loads in turn varies depending on the level of electricity prices on the markets, the retailer's hedging and resulting open position. Thus, in practice, the applied tariff structure, but also many other factors has high impact on the principles, based on which upper level optimisation should be planned. However, electricity price is the factor, which typically has the impact on the overall benefits. Thus, and in order to simplify the examination, the control signals are formed based on the hourly electricity prices.

Figure 3.2 present an example scheme, which illustrates customer load control based on the introduced model.

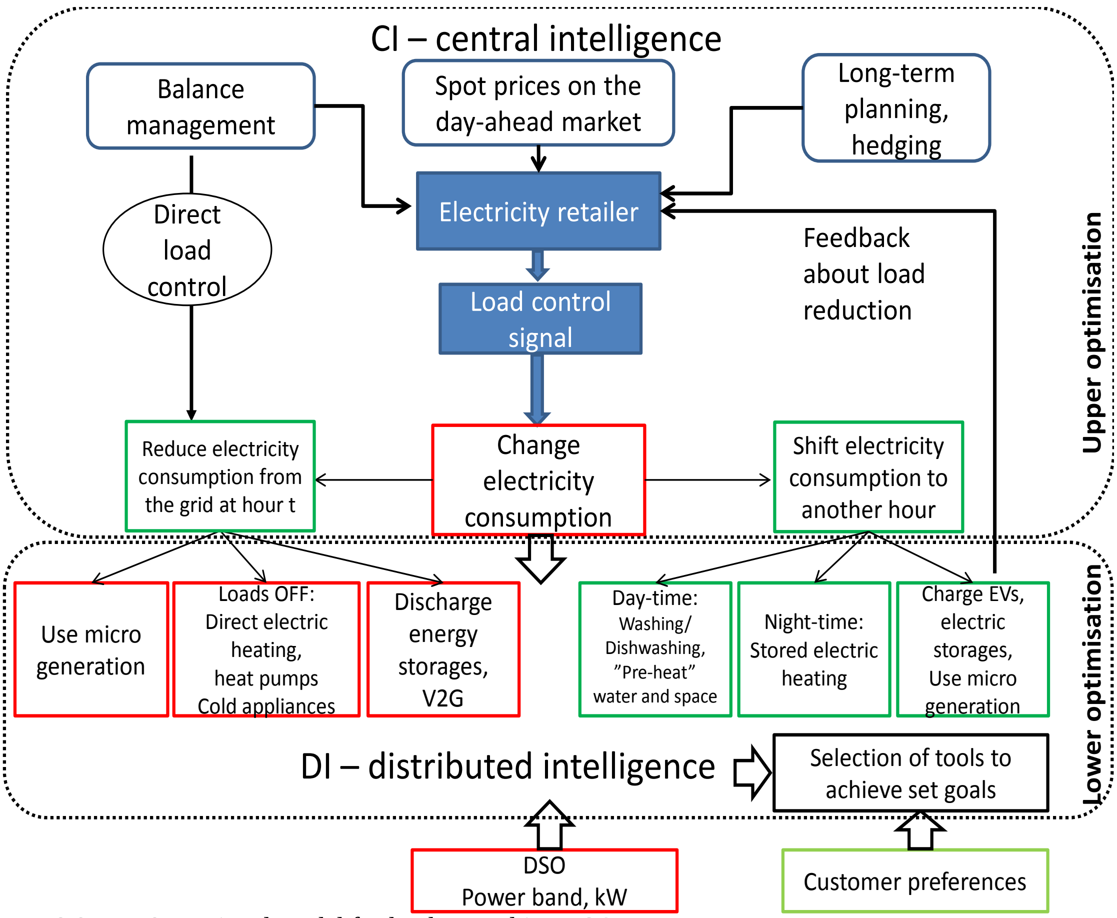

Figure 3.2. Operational model for load control in INCA.

Figure 3.2 shows that the optimisation is done in two levels in this model. The *upper level optimisation*, which would be the retailer's optimisation in practice, is done by the central intelligence (CI). In the upper level optimisation the data on customer's controllable loads, feedback about load reduction and electricity prices are used to form the load control signal. The control signal is then sent to the customer interface, where the distributed intelligence (DI) does the *lower level optimisation*.

The lower level optimisation can be done based on different principles and within different constrains. At this stage the lower level optimisation is based on control signals and the set load priority list within the limits set by features of the loads. Figure 3.3 illustrates the lower level optimisation in the customer interface and its central element.

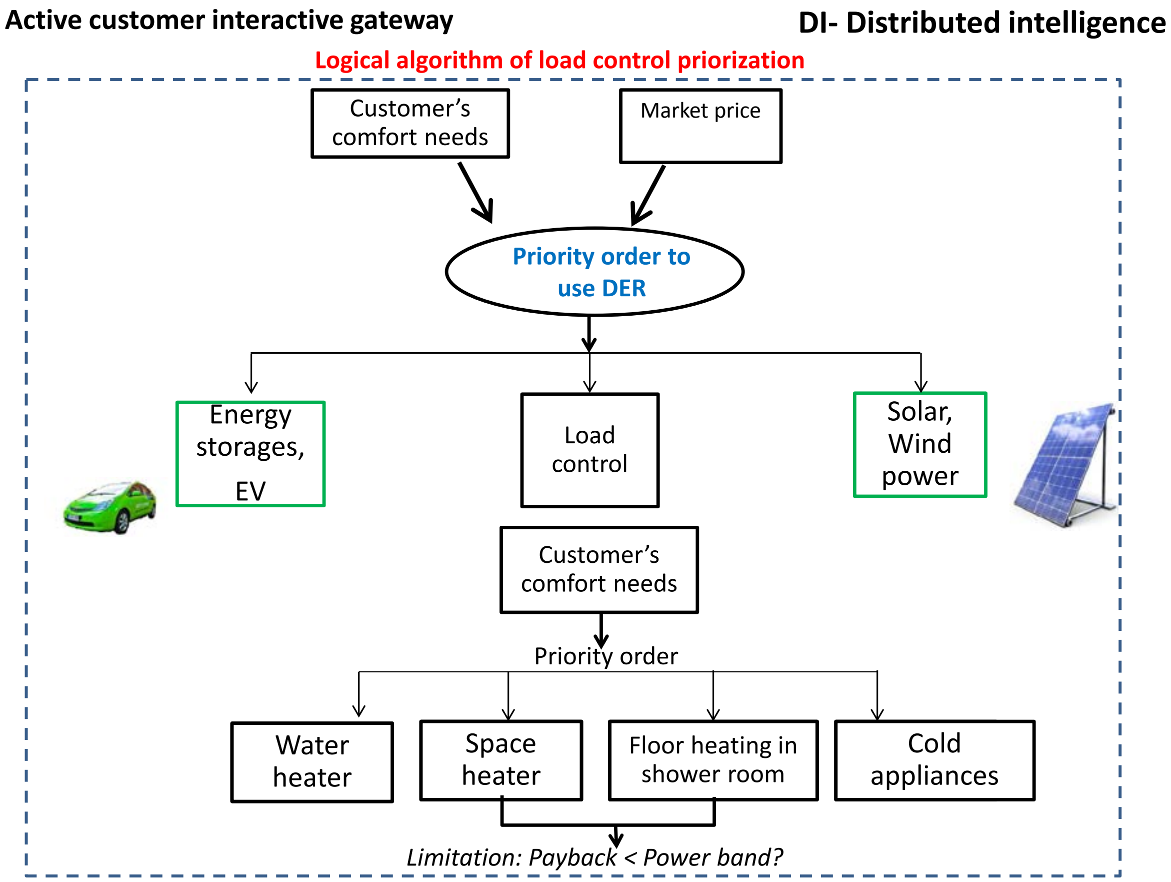

Figure 3.3. Lower level optimisation task

3.1.1 *Mathematical formulation of lower level optimisation task*

The upper level optimisation problem is already formulated in chapter 2. On the lower level optimisation the priority order to use DER at the customer's premises is defined based on the customer's comfort needs and market price value.

The priority order to use DER gives an answer to the question, which of the three options (energy storages, load control or micro generation) and how is economically beneficial to use in every hour of the considered period?

In any case it is always the most beneficial option to use the local generation for own needs, for instance to charge the energy storage or use for the own electricity consumption needs during high price hours.

During the high price hours the choice between energy storage discharging and load control is made based on the price value and cost of the battery. If the hourly price is below the marginal value for energy storage discharging, the focus is shifted to the load control implementation. Load control is carried out according to the priority order based on the customer's preferences. At the same time, exceeding of the power limit has to be avoided.

During the low price hours, energy storage can be put to the charging mode, if it does not coincide with high electricity consumption of the customer and the power band allows that.

Mathematical interpretation of the lower level optimisation, from the energy consumption perspective can be presented as follows:

$$\int_0^{24} p(t)_{€/MWh} * E(t)_{MWh} dt \rightarrow min \tag{10}$$

$$E(t) = E(t)_{uncontrol} + E_{DER}(t) \tag{11}$$

$$E_{DER}(t) = E(t)_{controllable} \pm E_{ES}(t) - E_{MG}(t) \tag{12}$$

$$\rightarrow E(t)_{controllable} = E(t)_{water\ heating} + E(t)_{space\ heating} + E(t)_{floor\ heating} + E(t)_{heat\ pump} + E(t)_{cold\ appliances} + E(t)_{wash/dishwash}$$

$$\rightarrow E_{ES}(t) = E(t)_{EV} + E(t)_{energy\ storage}$$

$$\rightarrow E_{MG}(t) = E(t)_{solar} + E(t)_{wind}$$

The functioning of the proposed model can be illustrated through case examples presented in following sections. The example case one presents the use of large-scale load control of direct electric heating and water heating loads as a tool to maximize retailer's profits. The case two presents the use of direct electric heating loads for the minimisation of customer's energy costs.

3.2 Case: Retailers profit maximisation

This case example illustrates the use of load control as a tool to maximize retailer's profits in a short-term. The optimisation model calculates the theoretical saving potential that the hypothetical DER control potential can provide for the retailer under examination. The calculation of saving potential within the time period of 1 Oct. 2011 – 31 March 2012 is made by using actual electricity sales data of a Finnish retailer and historical electricity prices.

The impact of load control on the retailer's profits is evaluated in two scenarios. In scenario one DER controls are made based on spot prices. In scenario two, the impact of load control on the retailer's profits are calculated based on the historical consumption imbalance power prices. This illustrates the active management of retailer's open position based on the prevailing market situation. In practice, however, imbalance power prices are known only after the delivery, and thus, it should be borne in mind that results of this scenario shows the theoretical maximum saving potential.

The retailer's hypothetical DER control capacity is estimated based on the data of the retailer's total sales to residential retail customers' and the data of the Finnish households' electricity usage study. A detailed description from the methodology used for the evaluation of DER control capacity can be found in (Valtonen 2012). The retailer's hypothetical DER control capacity consists of the retail customers' aggregated water heating and direct electric heating loads. The estimated load control response, when a load control command is given by the retailer, approximates 10 % of the retailer's hourly sales to the residential retail customers. Limitations on the load control set by the customers' comfort is taken into account by setting the maximum continues disconnection of loads to one hour during the permissible control periods, 6 to10 a.m. and 17 to 21 p.m. (Valtonen 2013)

The model determines the optimal load control time within each control period, and calculates the effect of the load control on the retailer's profits. Results are presented in figures 3.4, 3.5 and 3.6, and in Table 3.1. Fig. 3.4 and 3.5 presents the same results, but the graph in Fig. 3.6 has been made more illustrative by setting the maximum y-axis value to 4000.

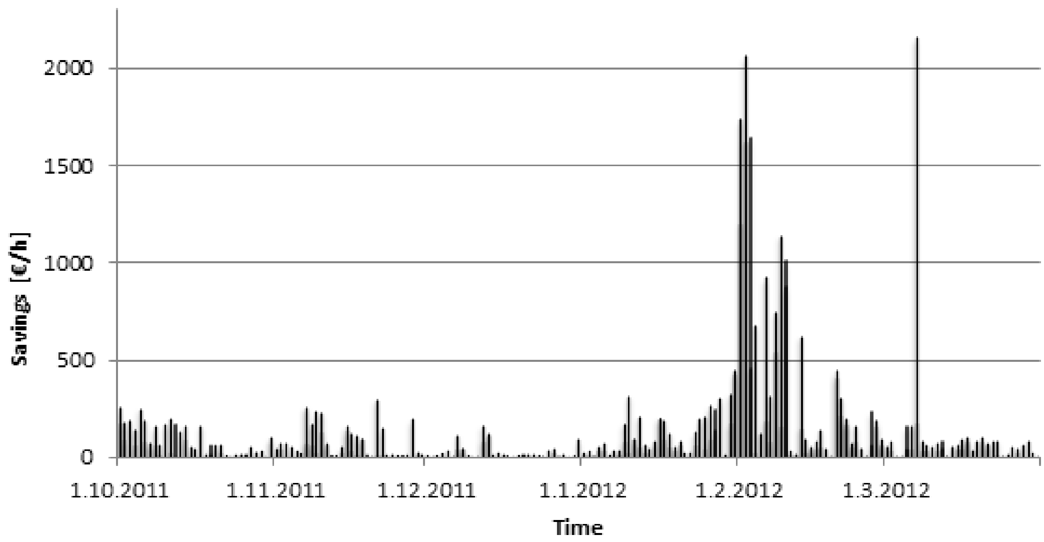

Figure 3.4. Saving potential for optimized load control based on spot prices (Valtonen 2013)

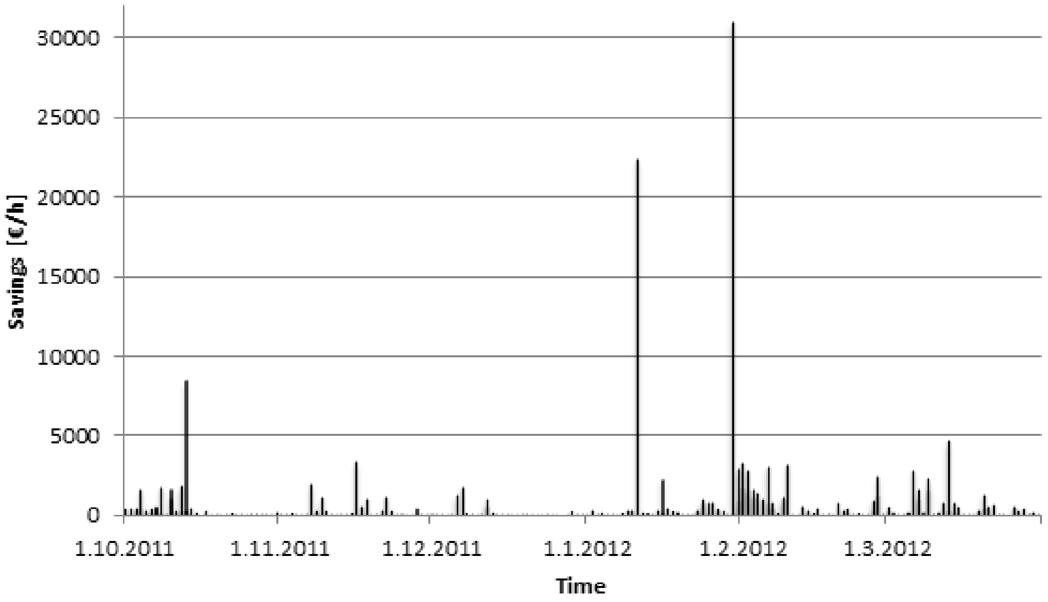

Figure 3.5. Saving potential for optimized load control based on consumption imbalance power prices (Valtonen 2013)

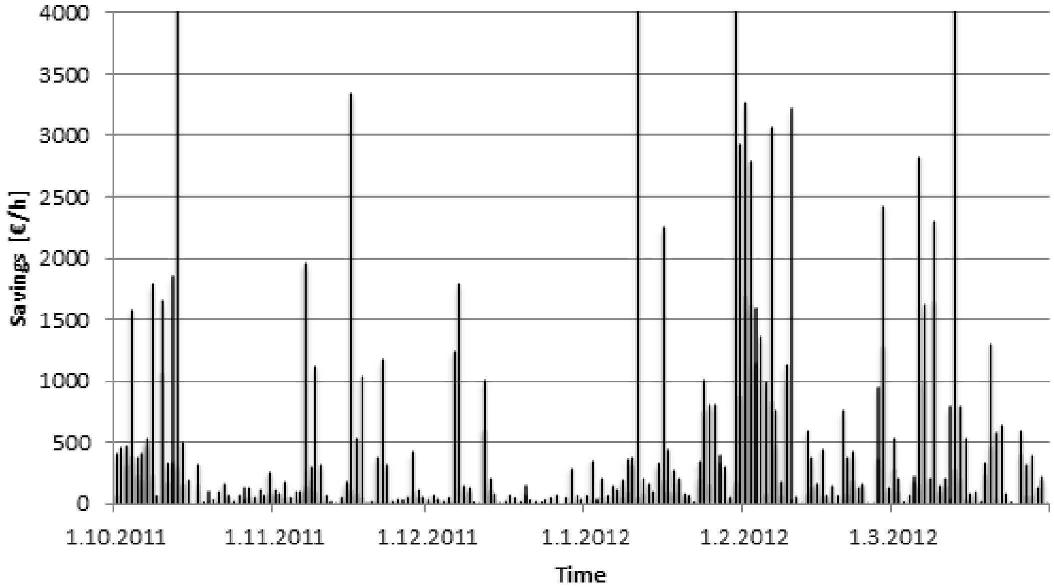

Figure 3.6. Saving potential for optimized load control based on consumption imbalance power prices, zoomed figure. Y-axis values are limited to 4000. (Valtonen 2013)

Figure 3.4 shows saving potential within each control period in scenario one, and Figures 3.5 and 3.6 in scenario two. Table 3.1 presents the characteristics parameters describing the effects of load control in both scenarios. Figures 3.4, 3.5 and 3.6 shows that significant saving potential can be found in both scenarios.

Table 3.1. Optimisation results (Valtonen 2013)

	Scenario 1: Load control based on spot prices	**Scenario 2: Load control based on consumption imbalance power prices**
Total savings [€]	39825	178117
Average savings [€/h]	236	545

Highest saving [€/h]	2157	30923
Highest sifted energy during one hour control [MWh/h]	18.8	18.6
Lowest sifted energy during one hour control [MWh/h]	7.3	7.4

As Table 3.1 shows, the retailer can achieve savings in both scenarios, if load controls can be put in practice with low costs. However, load control based on the consumption imbalance power prices provided over four times higher saving potential than load control based on spot prices. Total saving potential in scenario one was approximately 40000 € when sifted energy usage varied 7.3 to 18.8 MWh/h, and in scenario two 178 000 € when sifted energy varied 7.4 to 18.6 MWh/h. This indicates that active management of open positions could be an effective way to improve retailers short-term profit optimisation in a smart grid environment, although it includes higher risks than load control based on spot prices. (Valtonen 2013)

3.3 Case: End-customer's energy cost minimisation

The price difference approach defines the following rules to be implemented on the market-based load control (Belonogova, 2013):

1) Controllable power is turned off at the hour when the price difference between that hour and the following hour is higher than the value given for the load control cost.
2) It is not allowed to disconnect the load during the hour of load reconnection for the sake of customer's comfort. If the price difference is high enough also between the following couple of hours, the following combinations of disconnection are possible:
   a) All controllable power is disconnected during the hour t, no load disconnection occurs during the hour t+1
   b) All controllable power is disconnected during the hour t+1, no load disconnection occurs during the hour t

3.3.1 *Controllable load*

The task to find the minimum level of consumption at each hour of the day, when the comfort of customer is satisfied, is challenging. This task can be turned into finding the controllable power at each hour of the day. The controllable load is assumed to be electric heating in this study. First, rough assumptions have to be made about controllable power.

On one side, the controllable power depends deterministically on the heating solution (direct electric heating, partially stored electric heating, stored electric heating, heat pump) and outdoor temperature. It is also dependent deterministically on the insulation of a house and its space heating area.

On the other hand, controllable power depends stochastically on the customer individual preferences. The combination of these deterministic and stochastic dependencies makes it challenging to estimate controllable power for a single customer.

The customer individual preferences can be expressed by the desired indoor temperature, which varies during the day depending on whether the customer is present at home or not, sleeping or active.

Before the load control scheduling, the retailer makes estimation of the controllable power based on the outdoor temperature forecasts (estimation of electric heating load) as well as feedback about previous load control events.

For the simulations of load control, a sensitivity analysis, when controllable power changes within certain limits, could be useful to estimate in which boundaries the impact on load curve and energy cost savings is changing.

3.3.2 *Duration of disconnection*

The second parameter needed in the optimisation, is duration of disconnection. This depends on the heating method. In this regard, it is necessary to bring up the term "electric heating storage capacity". For direct electric heating, the capacity is low. This means, that a heating element cannot store much heating once at a time, cools down fast (depending on the difference between indoor and outdoor temperature, and insulation of the house) and has to be supplied by electricity many times during the day. Stored electric heating, on the contrary, has high heating capacity, slowly cools down, emitting the heat to the surrounding air and can be without electricity many hours. Therefore, duration of disconnection may be short for direct electric heating and long for stored electric heating loads. This means, that the energy cost optimisation algorithm will generate a different optimum set of load control events for different types of heating loads.

For this combinatorial optimisation task the day is divided into 12-hour periods. The vector k consisting of 0 and 1 is formed for each hour, where 1 corresponds to the case when load control could take place due to the high enough price compared to the price of the following hour. After that, the iterative process generates all the possible combinations of disconnections and selects the one with maximum savings from the load control actions according to (1). The optimisation algorithm is illustrated in Figure 3.7.

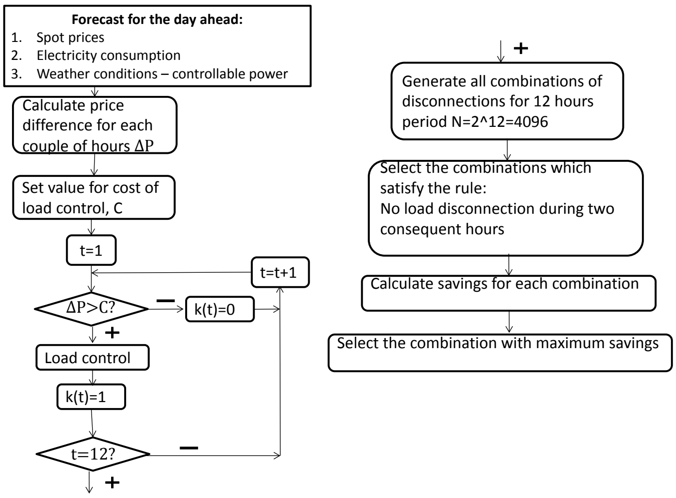

Figure 3.7. Energy cost optimisation flow chart

Here is the example of spot-price based load control on three types of customers:

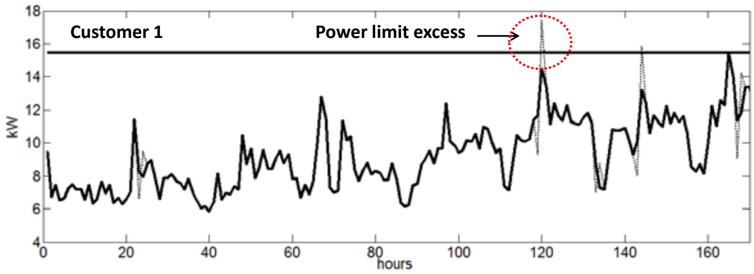

Figure 3.8. Example of a customer's consumption behaviour from the cluster 1, price-based load control causes peak power level excess

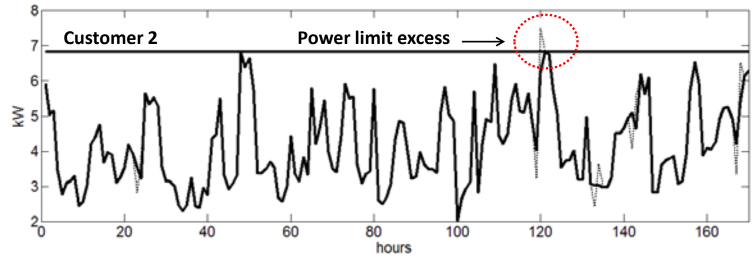

Figure 3.9. Example of a customer's consumption behaviour from the cluster 2, price-based load control causes peak power level excess

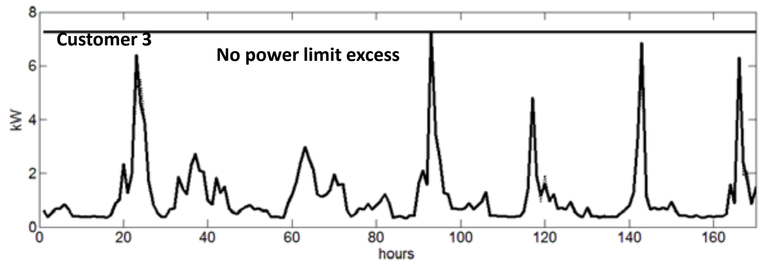

Figure 3.10. Example of a customer's consumption behaviour from the cluster 3, price-based load control does not cause peak power limit excess

The results show that for the customers with a low peak-to-average ratio (PAR) (customer 1 and 2), i.e., with a peak power value close to the average power consumption, the risk of exceeding the peak power limit as a result of load control is higher. For load curves with the high PAR instead (customer 3), the risk of exceeding the maximum peak power is low. It has to be borne in mind that the demonstrated results are case-sensitive. The risk of higher annual peak powers depends primarily on the weather conditions and price volatility. The risk is higher during cold weathers when the electric heating load level is high, as well as during high price volatility periods when the load control is likely to occur.

4 Implementation

A test system for the proposed multi-objective control system for INCA has been implemented in laboratory as a part of LVDC research platform. The LVDC-system simulates single household with eight controllable loads and has also one generation unit which can produce a maximum of 1.2 kW. With the setup the operation of the control algorithms can be tested and impacts of different kinds of initial conditions or weighting of the objectives of different market parties simulated. The main components of the realised INCA pilot system are:

- Customer-end inverter of the LVDC-system
- 8 controllable household loads
- Relay control for loads
- HydroBoy grid inverter (1200 W)
- AC/DC power source
- Embedded PC with SQL database (the actual "brains" of the INCA – distributed intelligence)
- Matlab PC (retailer/DSO optimisation and external control – centralised intelligence)

The structure of the INCA laboratory pilot is illustrated in Figure 4.1.

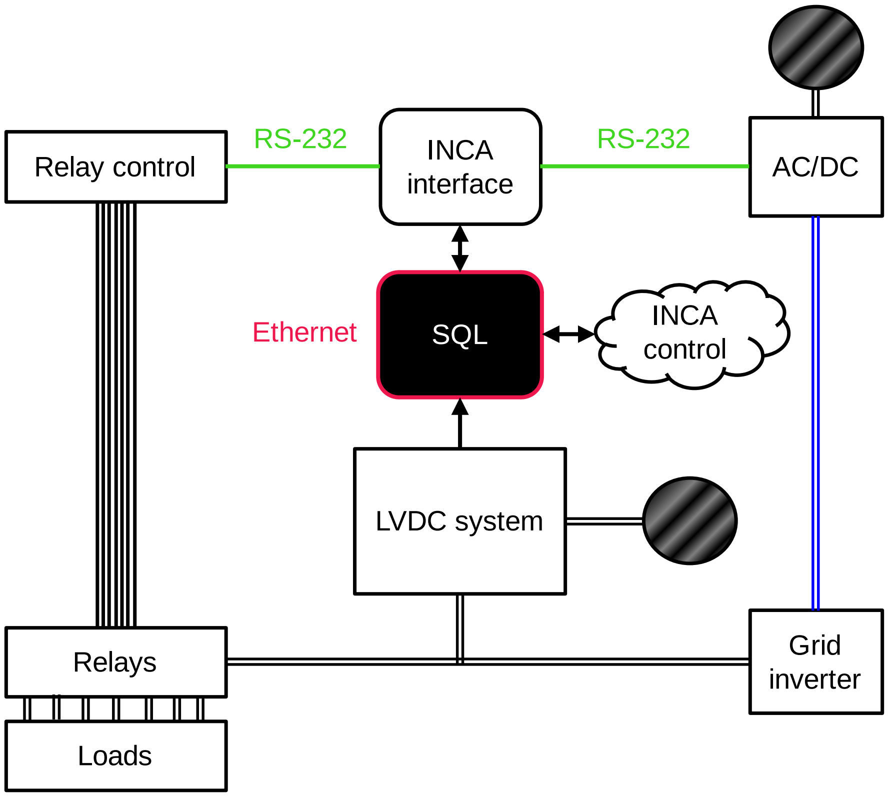

Figure 4.1. Technical structure of the INCA laboratory setup.

The INCA interface controls AC/DC power source and relay control with a RS-232 interface according to the instructions in SQL-database. The INCA interface also updates the current relay and AC/DC status (power) to the SQL-database for the optimisations. The INCA control also needs current power which is provided by the LVDC systems measurements.

The INCA interface can control eight "customer loads". Six of these loads are fixed, three of 1830 W and three of 2520 W. The two remaining relay spots can be used for different size of loads, controllable or uncontrolled (manual).

In addition, grid inverter can be used to simulate energy storage or distributed generation with a maximum power of 1200 W. The power can be controlled with AC/DC power source with a 10 W resolution.

4.1 Communication and information exchange

The upper optimisation (central optimisation) in the INCA concept is done based on the customer load forecast, customer load curve (present load) and electricity market. The upper optimisation presents TSO, DSO, retailer or aggregator optimisations, giving price signal and load signal for the lower optimisation (local optimisation). The lower optimisation controls the household units based on price and load signal from the upper optimisation and load priority and load curve from the customer side. The lower optimisation needs also to take the customer load behaviour into consideration, as the customer's actions cannot be fully forecasted. Hence, the lower optimisation must be adaptive. The concept of INCA communication is presented in Figure 4.2.

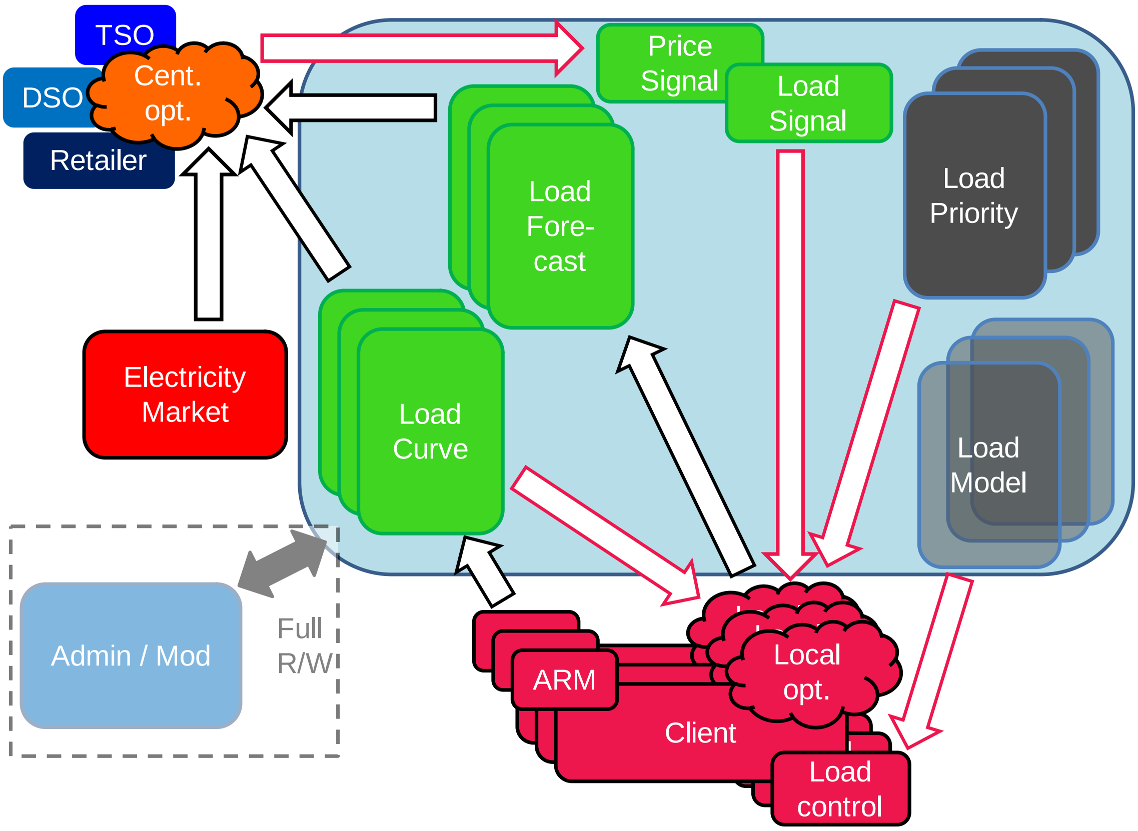

Figure 4.2. The concept of INCA communication structure.

The unpredicted customer behaviour is presented in Figure 4.2 as a load model. Even though customer behaviour can be somewhat forecasted (load forecast), the load model presents only the current actions of the customer, giving no information for the future behaviour.

The price signal can vary from -100% to 100% (value -100 to 100 with an accuracy of 1), guiding customer optimisation to increase or decrease consumption. The values of the price signal are inserted in a SQL database, allowing lower optimisation to access price signal information for the next 24 hours. Same procedure is applied with load signal which can vary from 0% to 100%.

The lower optimisation takes the price and load signal into account with the load priority list and current load curve when producing optimized load table. While the optimisation decides the needed actions, it also forms the load forecast for the upper optimisation, creating feedback loop. Hence, the upper optimisation acquires information how much controllable load is available for next hours, allowing it further optimize the load or price signal for the next hours.

The INCA laboratory pilot follows the presented INCA communication structure with a few exceptions. The upper and lower optimisations are done in the same interface (Matlab) at first phase, giving already optimized load table for the INCA customer interface. Also, the load model is pre-set for the loads for next hours in the SQL database. However, the load model information is not used for the optimisations, simulating unpredicted actions of the customer.

The relay control is done based on the relay instructions in the optimized load table. After the instructions have been made, the INCA interface uploads the current status of the system for the lower and upper optimisation. The information structure of the first and second phase is presented in Figure 4.3

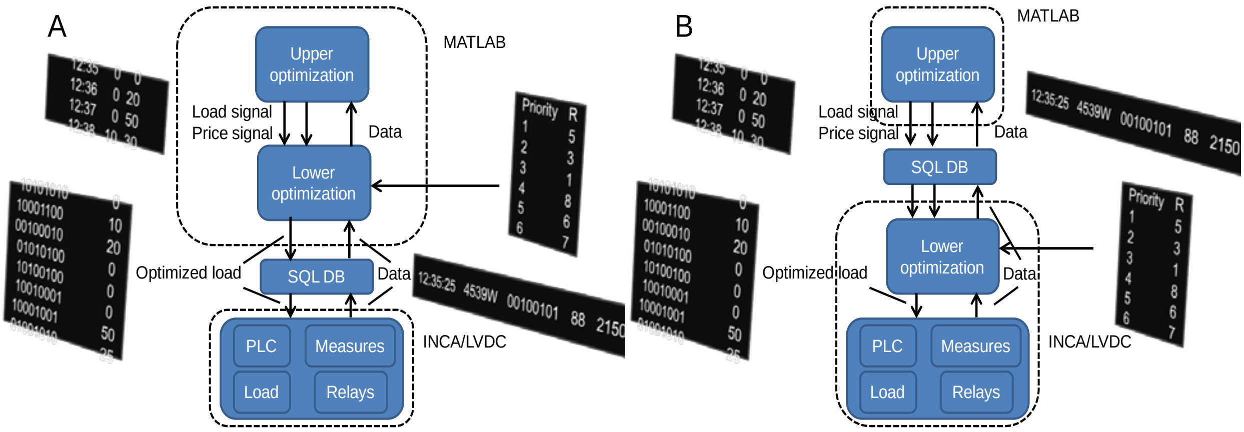

Figure 4.3. Information structure of INCA laboratory pilot at first phase (A) and second phase (B).

The SQL database structure is identical on both phases, except for the price and load signals which are internal at first phase (A) and only emitted to the SQL database at second phase (B). Also, as Figure 4.3 illustrates, the lower optimisation is shifted as a part of the INCA/LVDC-system at the second phase, simulating physical customer interface. This information structure can be shifted to fit generally the need of the INCA concept by modifying the interface between lower optimisation and the LVDC-system. The Figure 4.4 illustrates general information structure of INCA concept.

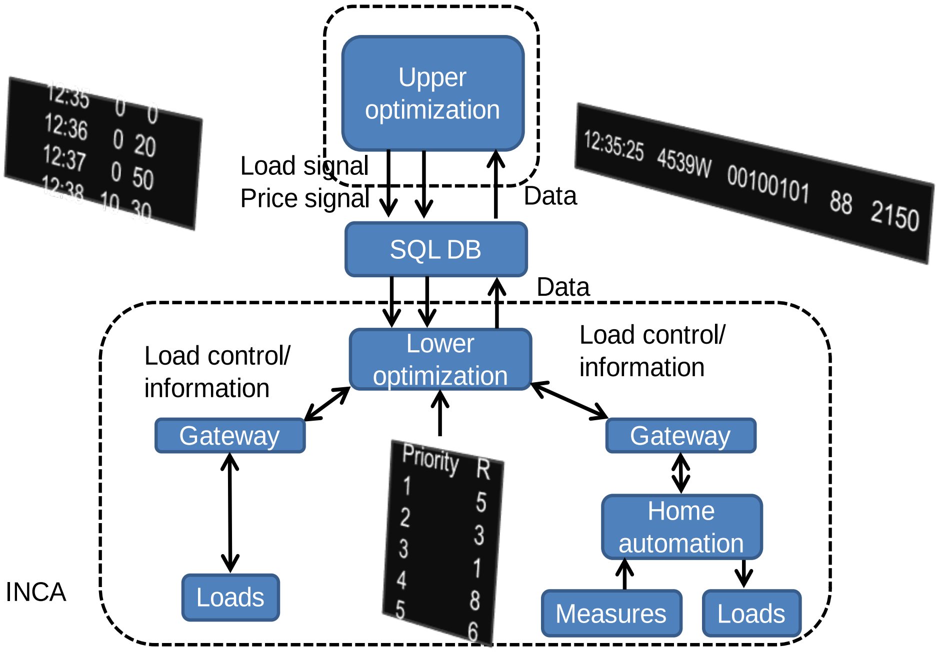

Figure 4.4. General information structure of INCA concept.

5 Conclusions

In this report the objectives and technical realisation of the energy optimisation on the interactive customer gateway were discussed.

The most challenging task in the implementation of the interactive customer gateway concept lay in the development of the optimisation algorithms combining the objectives of the business players with the needs of the end-customer. The objectives of a retailer, a DSO and a single customer on the optimisation problem were verbally and mathematically described, with objective functions and constraints listed. It was emphasized that the load control results into the conflict of interests between the involved parties if carried out independently according to the party's own interests. Therefore the total optimisation task represents a compromise between all parties, where the retailer controls the loads within the customer's and DSO's constraints. The optimisation principles on the upper level (retailer) and lower level (customer) were presented. It was shown that the interaction between all parties is essential to deliver benefits to all parties.

Another outcome of the report is a description of the technical implementation of the optimisation algorithms in the laboratory environment. The presented methods and algorithms can and will be applied later in the Green Campus environment. The optimized use of wind and solar power generation together with electric vehicles as mobile energy storages, static energy storages and electricity consumption will demonstrate the opportunities of smart energy usage patterns and active control.

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