Economic Impact of Demand Response on Costs to Distribution System Operators

by

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Abstract

Current transmission and distribution units are designed to cope with extreme cases of maximum power demand, which sparsely occur. Dimensioning the grid to such specifications for the purpose of meeting temporary peak load is a costly endeavor which can be lowered via exploitation of load modification. Demand response potential is estimated to be high in European power systems with high penetration of renewable energy sources. Implementation of demand response has been slow to emerge, especially amongst residential users commonly attributed to limited knowledge on the scope of potential savings that can be achieved (Torriti et al., 2010). This work investigates the aggregate economic impact of demand response on costs to distribution system operators in Sweden. The simulation indicates that demand response has the highest savings per customer per year when postponing future grid investments followed by lower grid fee to feeding costs and power losses.

1 Introduction

The European Union is aiming to reach a 20% increase in energy efficiency and a 20% emission reduction compared to 1990 levels in addition to 20% of electricity production from renewable energy sources (RES) by 2020. In order to meet policy objectives the current power system will undergo radical changes in the coming years. Along these lines, the Swedish government has adopted a framework which has the ‘planning goal’ of expanding wind power capacity to 30 TWh[7] (20 TWh onshore and 10 TWh offshore) by 2020 (Swedish Energy Agency, 2010). Moreover, as of 2010, Sweden became the first European member state to achieve a full-scale deployment of smart meters in households, putting the country at the forefront of exploring the potential of residential load management (Hierzinger et al., 2012). The implementation of demand response is one of the most investigated solutions oriented towards the improvement of electricity market efficiency and maintenance of power system reliability. Demand response (DR) is regarded as a modification of electricity consumption in response to price of electricity generation and state of system reliability (ACER, 2012; DOE, 2006). Load management can have a twofold impact: (i) flexibility supply to balance the system (especially in a system with high RES penetration) and (ii) alleviation of grid overload (Strbac, 2008). This work explores the latter impact of demand response for the distribution system.

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[7] Terra-watt hour

At present, transmission and distribution units are designed to cope with extreme cases of maximum power demand, which sparsely occur. However, dimensioning the grid to such specifications is a costly endeavor (Bartusch et al., 2011). Demand response is a tool that can be used by grid operators to reduce such load variations. General actions which a customer can take when subject to demand side management include (i) a reduction consumption during a peak periods where prices are high or use of onsite electricity generation (solar PV, storage etc.)[8] and (ii) shift consumption during peak periods to off-peak (Albadi and El-Saadany, 2008).

In Sweden potential resources for demand response are estimated between 3.300 to 5.500 MW[9], which equals 10 to 20 percent of maximum power output (Bartusch et al., 2011). Nevertheless, although DR potential is high, implementation has been slow to emerge in Swedish (and in general European) power markets commonly attributed to limited knowledge on the scope of potential savings that can be achieved (Torriti et al., 2010). This study focuses on uncovering the economic impact demand response from residential users has on costs to Distribution System Operators (DSOs) in Sweden. Section 2 describes the simulation method used for this work followed by an analysis of the results in section 3. Section 4 provides some conclusions and recommendations for distribution system operators and regulators when considering the implementation of demand response mechanisms.

2 Methods

In order to understand how demand response may affect the DSO economically, it is important to have insight into what drives the distribution business. Fundamentally, a DSO distributes electrical energy to consumers while operating as a natural monopoly subject to regulatory oversight for tariff remuneration. The Swedish Energy Markets Inspectorate establishes the set of rules which determine the frame of income for the DSOs before each period of supervision (EI, 2009), currently running from 2012 to 2015. The remuneration has a focus on revenues with the regulator deciding a cap which will cover operational costs and returns on assets. More specifically, costs for the DSO are split into capital expenditures and operating costs. Capital expenditures are considered the asset base,[10] which includes the cost of assets and depreciation time during the period of supervision. Operating costs are split into controllable costs and uncontrollable costs. The latter uncontrollable costs do not have any efficiency requirement and are directly passed on to the customers. Typical, uncontrollable costs consist of distribution *network losses*, taxes and authority fees in addition to charges the DSO has to pay to be connected to sub-transmission level, commonly referred to as the *grid fee to feeding grid cost* (EI, 2009). Meanwhile, the former controllable costs are influenced by demand side efficiency, forcing the DSO to improve operation over time.

State of the art literature concerning the role of the distribution system operator in the Swedish electric power system (EI, 2012; ERGEG, 2008; Söder and Amelin, 1999) reveal the economic forces behind the DSO's business (EI, 2009; E.ON, 2013) and the effects of implementing demand response programs (Capgemini, 2008; Balijepalli et al., 2011; Shaw et al., 2007). In order to gain deeper understanding into the sometimes intricate and complex interdependencies of legislation, technologies and business operations that drive the functioning of Swedish distribution systems a series of interviews have been conducted with the CEO of Sala-Heby Energi Elnät AB (Mårtensson, 2013a; 2013b), a Swedish DSO with experience in successfully implementing demand response programs. This research revealed that benefits from demand response for Swedish DSOs will have the highest

8 For a DSO both actions will have the same effect on the grid i.e. less electricity transferred through the network.
9 Megawatts
10 Assets that included in the asset base are lines, cables, substations, transformers, systems for operating distribution assets and meter reading systems (Boström and Pettersson, 2011)

economic impact on the following factors: *power losses*, *grid fee to feeding grid costs*[11]and *postponed future investments*. Note, maintenance was also found to be an influencing factor but was disregarded due to complex interactions with demand response yielding uncertainty in simulation outcomes. Furthermore, the focus of this simulation is not to design a perfect demand response program for the DSO but rather to convey an example of the magnitude of benefits any DSO can gain via the utilization of load management. As such, the demand response model (described in detail below) was constructed in such a way that is relatively simple to implement for most, if not all, Swedish DSOs.

2.1 Simulation

Sala-Heby Energi Elnät AB provided distribution load data[12] from 2007 to 2012 for this analysis[13]. The data consists of figures on the energy imported through the feeding grid and the energy produced within the DSO's own network. Therefore, the total demand including losses, for which the data is aggregated on an hourly basis in kWhs[14] (for the entire distribution area) yields the Basic Load Curve (BLC) as a result of *equation 1*:

Equation 1: $$\bar{E}_{BLC} = (x_1 + y_1, x_1 + y_2, \ldots, x_n + y_n)$$

where $\bar{E}_{BLC}$ is a vector containing hourly data of the total demand including losses in the DSOs grid over a year, x is the data point for each hour of imported electricity over the whole year and y the hourly produced electricity over the whole year (see Figure 1).

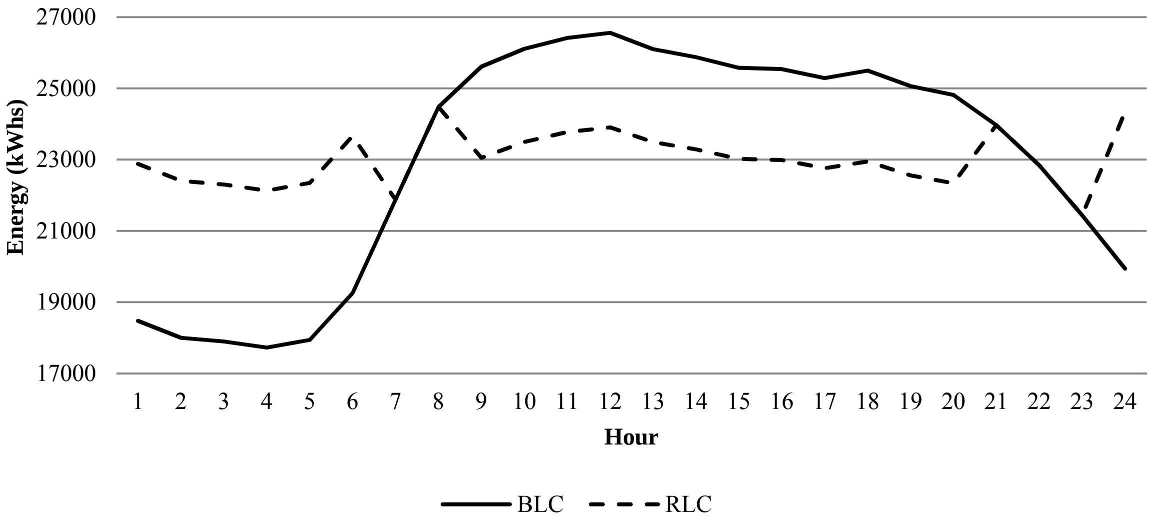

Figure 1: Average daily load curves

[11] The Swedish Grid has three levels (i) transmission grid (ii) regional grid (iii) distribution grid. The grid fee to feeding grid is based on the cost imposed on the DSO by the owner of the regional grid which transfers electricity into the DSO's grid. If the power transferred is higher than the level of the subscribed maximum power, this fee has to be paid to the regional grid manager. This fee is quite costly to the DSO, and in order to hedge against there are contracts between grid mangers resulting in a high subscribed max power

[12] This includes both the energy fed into the distribution grid through the sub-transmission level and the electricity that is locally produced within the distribution area.

[13] On average, Sala-Heby Energi Elnät AB is considered to be a smaller than average DSO when compared to other Swedish operators. Sala-Heby Energi Elnät AB has 13.211 customers with a total demand of 199.690MWhs.

[14] Kilowatt hours

In the simulation, the program for load management is modeled as a Time of Use[15] tariff, since this is what has been implemented by Swedish DSOs in the current system. As seen in Figure 1, it has observed that the average load is at its highest between the hours of 09:00 and 20:00. For the DR simulation, during peak hours consumption is reduced by an arbitrarily chosen value of 10%. The reduced energy is then distributed evenly among the off-peak hours between 23:00 and 08:00. The hours between the peak and the off-peak are considered to be unaffected by demand response. Following load management, a Resulting Load Curve (RLC) is assessed against the Basic Load Curve in order to see the impact of implementing demand response (see Figure 1). The RLC is derived as follows:

Equation 2: $$\bar{E}_{RLC} = f(\bar{E}_{BLC}) = (z_{1,RLC}, z_{2,RLC}, \dots, z_{n,RLC})$$

where $\bar{E}_{RLC}$ is a vector containing hourly data of the total demand (including losses) in the DSO's grid over a year modified by the DR estimation $f(x)$, with z as the vector corresponding to each hour over the whole year with the same modifications. Evidently, the model only takes peak load shifting into consideration, which carries a positive connotation, but it may also affect the DSO negatively since the main income is based on the tariff to the consumers that is set over the regulatory period (2012 to 2015). For instance, a decrease in overall consumption will also result in an overall income reduction for the DSO. The analysis regarding this is quite complex and is not handled in this work since the aim of this model is to look at the positive economic impact of the implementation of demand response.

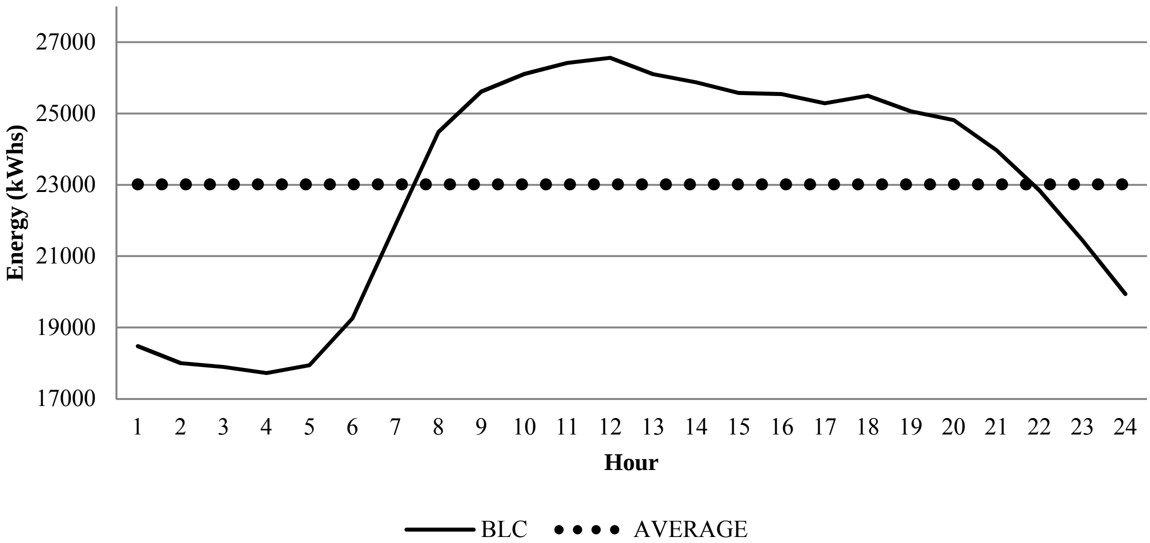

Figure 2: The BLC of Sala-Heby Energi Elnät AB compared to the average hourly value for the year 2012

The maximum impact of load management is achieved when the load curve is flattened out throughout the day. Such a simulation yields optimal demand response implementation as a result of peak load shifting (see Figure 2). Thusly, simulation analysis is conducted under the following two scenarios:

- *Scenario 1* takes into consideration 10% demand response from peak load shifting during peak hours and evenly distributes load over the off-peak hours

[15] Time-of-Use (TOU): varying by season, day of the week and time of day with predefined unit prices for 2 to 3 different blocks of time throughout the day aimed at reflecting average varying cost of generation (Braithwait and Eakin, 2002; Bossart and Giordano, 2012; FERC, 2012).

- *Scenario 2* looks at the best case scenario where the load curve is flattened out throughout the day yielding an evenly distribution of load.

The discussion continues below with an analysis of the factors which impact Swedish DSOs the most (*power losses*, *grid fee to feeding grid costs* and *postponed future investments*) following the implementation of demand response under *scenario 1* and *scenario 2*. See Figure 3 for a layout of the demand response model which results.

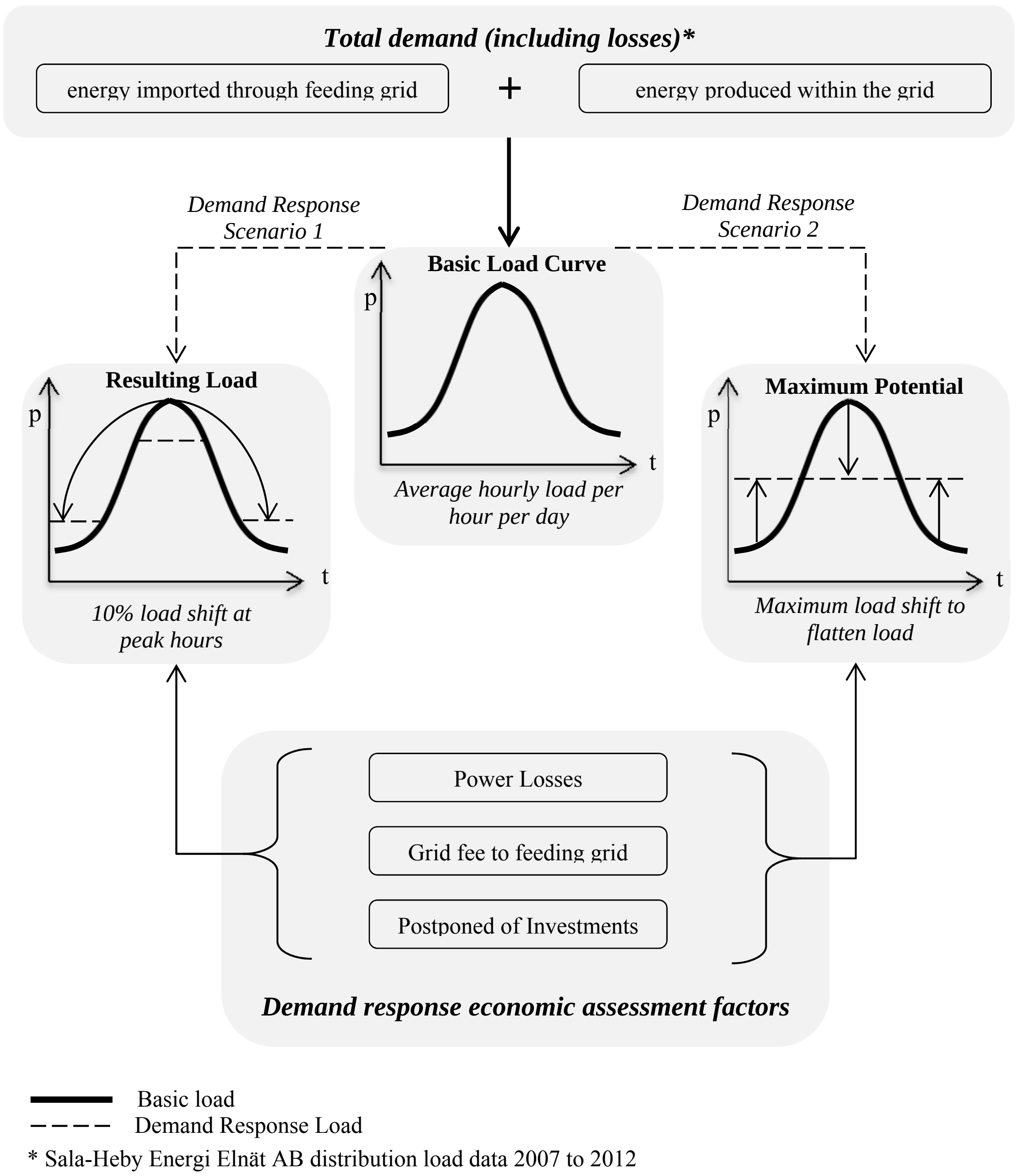

Figure 3: Demand Response Model Layout

2.2 Power losses

Power losses are defined as the difference between the amount of electricity entering the distribution system and the amount of consumption, when aggregated, which can be registered at the metering points of end-users (ERGEG, 2008). Real values of distribution losses can be calculated by using the difference between the hourly input (production) and the hourly output (consumption) of electrical energy. For the model, the hourly input energy is obtained from actual Sala-Heby Energi Elnät AB measurements while consumption data at individual points in the grid is not used[16]. Since the investigation is focused on the aggregate impact of demand response, this part of the model assumes that load is equal in all parts of the distribution grid and that the losses are evenly spread throughout the network.

Losses can be further broken down into technical and non-technical. The latter non-technical losses consist of electricity which is delivered but not paid for as a result of own consumption from the DSO, energy theft, non-metered supplies (e.g. public lighting), and errors in metering, billing and data processing (ERGEG, 2008). Although non-technical losses are costly and relevant for the DSO, for this simulation they will be disregarded since they are not affected by load management. The former technical losses are caused by the conversion of electrical energy into heat and noise when flowing through grid components (ERGEG, 2008). Such losses can be fixed, since they primarily result from iron loss of transformers which is independent of the power flow and therefore irrelevant for this work. Moreover, technical losses[17] can also be variable resulting from the natural resistance found in power lines (Shaw et al., 2007). Loss through a power line is calculated from *equation 3*:

Equation 3:
$$P_f = P^2 * R * \frac{(1+(sin\Phi/cos\Phi)^2)}{U^2} = k * P^2$$

where P_f is the power loss, P is the reactive power, R is the resistance, Φ is the phase angle for active power $cos\Phi$ and reactive power $sin\Phi$ and U is the voltage. Reactive power is the only variable, the variable power loss is said to be proportional to the square of the power flow or the load within the grid. Since all but the reactive power is constant, *equation 3* can be simplified as follows:

Equation 4:
$$k = R * \frac{(1+(sin\Phi/cos\Phi)^2)}{U^2}$$

Accordingly, due to resistive losses being proportional to the square of the load, losses can thusly be reduced significantly if the existing load fluctuations in the distribution grid are normalized. In this way, the model assumes that the variable load is directly proportional to the square of the load. This proportionality is utilized to create a loss vector which varies with load output of the curve and the variable part of the mean arithmetic loss which the DSO provides. Sala-Heby Energi Elnät AB has a mean arithmetic loss of 4,3% and is used with *equation 3* to create a variable function of loss using the basic and resulting load curve (BLC and RLC) as inputs. The levels of loss at different points on the load curve are calculated in *equation 5*:

Equation 5:
$$\Delta_L = \frac{P_A^2 - P_B^2}{P_A^2}$$

where Δ_L is the associated change in loss percentage when the load goes from P_A to P_B (two different values on the load curve). This proportionality is utilized to create a loss vector varying with load output of the curve and the variable part of the mean arithmetic loss which the DSO provides. The percentage of the arithmetic mean loss corresponding to variable losses for both the BLC and RLC curves is established in as follows:

Equation 6:
$$L_{am,var} = L_{am}\,(1 - L_{fix,rel-to-var})$$

[16] Installed electricity meters in Swedish households have the capability of collecting data with such a resolution on an hourly basis. Such data is used to calculate individual electricity bills (Sweco, 2011), but for the purposes of this work since we are concerned with distribution.

[17] Resistive/variable losses occur in transformers as well as power lines. The fixed losses only occur in transformers.

where $L_{am,var}$ is the amount of the arithmetic mean loss that is caused by variable losses, L_{am} is the DSOs arithmetic mean loss over a year (given by Sala-Heby Energi Elnät AB at 4,3%) and $L_{fix,rel-to-var}$ represents the fixed losses in relation to variable losses out of the total arithmetic mean loss (Shaw et al., 2007), which for Sala-Heby Energi Elnät AB is 1 to 5 (Mårtensson, 2013a). The variable loss vector can then be compared using the load profile over the year that was created for BLC and RLC for determining the impact of DR in kWhs. Finally, the resulting value is then multiplied with pricing data from the Nord Pool spot market to estimate the aggregated economic impact. Note, Swedish DSOs are required to purchase electricity from the electricity market to cover the (technical) power losses within their grids (EI, 2009). It is the cost of these purchases that is considered to be the cost of losses that is passed directly to the consumer in the tariff. Accordingly, the procurement of losses has an impact on the DSOs finances as well.

2.2.1 Simulation results for power losses

The model shows that demand response has a maximum capacity to reduce annual losses by about 19% which leads to savings of almost $200 thousand per year. Such potential can be considered substantial for the chosen DSO since it amounts to approximately 2% of its yearly turnover[18]. If maximum peak load shift is achieved annual costs can be reduced by over of 36%. Moreover, the simulations indicate almost a 4% reduction in annual losses with savings over $40.000, a result much lower than that of the maximum potential but still with a significant economic impact (see Table 1).

Overall, the implemented demand response program achieves roughly 20% of the maximum potential of load reduction over the year. While incomparable to the magnitude of the maximum potential, the figures are far from negligible. Under *scenario 1*, load shifting yields an 8% reduction of the annual cost for power losses. The maximum annual potential gain for Swedish customers (*scenario 2*) is about $14 which is a relatively low value, seemingly of little importance to individual customers (see Table 1 for details). The current regulation (2012 to 2015) treats power loss as an uncontrollable cost, which through the tariff is passed directly to the customer, giving little incentive for DSOs to implement load management.

	Scenario 1	Scenario 2	Difference from maximum
Reduction in kWh over the year	346 756	1 635 036	1 288 280
Reduction in mean arithmetic loss	3,99%	18,81%	14,82%
Annual difference in USD	$40.260	$180.133,28	$139.873,12
Annual difference in USD per customer	$3,05	$13,64	$10,59
Reduction in annual cost (percent)	8,08%	36,14%	28,06%

Table 1: Simulation results for power losses after the implementation of Demand Response

Furthermore, the above simulation yielded an interesting secondary effect when losses are shifted from peak hours of the day towards the off peak hours in the night. If the DSO is using day-ahead spot market prices to purchase electricity in order to cover losses instead of using a fixed price ex-ante, the prices will typically be higher during the day and lower at night. In turn, this yields a positive economic effect when more losses are transferred from the day into the night. Additional exploration in comparing fixed pricing contracts and variable pricing contracts when compensating for losses in an environment where DR exists may prove very useful for further insight into these gains.

[18]Sala-Heby Energi Elnät AB has an average yearly turnover $8.798.560 from 2008 to 2012 (PROFF.se, 2013).

2.3 Grid fee to feeding grid

As previously mentioned, the cost imposed on the DSO by the owner of the regional grid for transferring electricity to the distribution grid is regarded as the *grid fee to feeding grid*. Since both networks are regulated monopolies, the same rules imposed by the Swedish Energy Markets Inspectorate on the DSO apply to the regional system owner as well. Most regional grids in Sweden are owned by Vattenfall, Fortum and E.ON (Svenska Kraftnät, 2012). Regardless of the owner there are three components (see Table 2) to the feeding grid tariff which are designed in the same manner and updated on a yearly basis (Fortum Distribution 2013; E.ON, 2013; Vattenfall Distribution, 2013).

Component type	Payment	Influence of Demand Response on grid fee to feeding grid and impact on simulation
Fixed	A ***fixed fee*** paid regardless of the amount of power or energy transferred	DR cannot impact this cost and is henceforth neglected in the simulation
Variable	A variable fee dependent on an agreement of a ***subscribed level of maximum power*** transferred for one whole year at a time	Load shifts from peak to off-peak hours and/or overall demand reduction, the level of the highest peak loads can decrease which in turn yields a lower subscribed level of maximum power transferred for the DSO
Variable	A variable fee dependent on the amount of ***energy transferred*** based on a fixed price for each kWh	Load shifting will not impact the outcome for this variable. Overall demand reduction will result in decreased total energy transferred and in turn yield a lower fee.

Table 2: Impact of DR on grid fee to feeding grid tariff components

The grid fee to feeding grid component of the simulation considers the cost impact of demand response on the two variable parts of the tariff (Table 2) utilizing Sala-Heby Energi Elnät AB data from 2007 through 2012. From this data, total transferred energy is calculated as follows:

Equation 7: $$\Delta_E = \sum(\bar{E}_{BLC} - \bar{E}_{RLC})$$

where Δ_E is the difference in energy transferred over the year, the result of the difference between the two load curves $\bar{E}_{BLC}$ and $\bar{E}_{RLC}$. With that, the difference in cost as a result of demand response is calculated in *equation 8*:

Equation 8: $$\Delta_{C,E} = C_{t,E} * \Delta_E$$

where $\Delta_{C,E}$ is the difference in cost resulting in a reduction in demand, $C_{t,E}$ is the tariff cost for the energy transfer and Δ_E is the difference in energy from load management.

As mentioned above, details of the subscribed maximum power and its fees are different depending on the regional grid operator. Nevertheless, there is always an element of risk involved which is based on the fluctuations in energy demand from customers coupled with the fee for surpassing the subscribed maximum power (Mårtensson, 2013b). When it comes to the risk of deviating, temperature variations from the Swedish temperate climate can have a devastating impact on DSOs. A cold year may increase electricity demand from residential customers, e.g. from 2008 to 2011 there was more than a 13% increase in consumption (ERGEG, 2008). Lower risk can be ‘bought’ by increasing one’s maximum subscribed power, in turn implying the existence of an optimal value for the DSO. Such a value exists in theory but in practice it is quite elusive. Lowering the subscribed maximum power to this optimal value brings about reduced added risk to high payments for deviations from the subscribed power level. Each regional grid operator optimizes for the subscribed level of maximum power in the following manner:

- **Vattenfall** calculates maximum power by using the mean of the two highest monthly load values for the year
- **Fortum** uses the mean of the two highest hourly values during each calendar week to determine maximum power (i.e. the level changes on a weekly basis)
- **E.ON** separates winter weekdays[19] from the rest of the year and then calculates its maximum power by using the mean of the two highest monthly load values for the year for each type of day

The estimation of the subscribed maximum power requires input of multiple years of hourly load data in order to capture the fluctuations in energy demand in between years. Such load data should be strictly limited to load that is imported to the DSO's grid through the feeding grid; thusly load produced within the distribution grid is irrelevant in this modeling step. For the simulation, data from Sala-Heby Energi Elnät AB for the years 2007 to 2012 is utilized in conjunction with prices from the regional grid operator Vattenfall. During this time, the cost of subscribed maximum power is $29,6 per kW while the cost of deviation is $44,4 per kW (Vattenfall Distribution, 2013). Regardless of the regional grid operator, the model imports load data over the set of years and then optimizes a level of subscribed maximum power as result of the lowest possible sum of costs for both BLC and RLC. The difference between these two optimal values estimates the change in costs after an implementation of demand response.

2.3.1 Simulation results for grid fee to feeding grid

The model results summarized in Table 3 show a maximum potential decrease in subscribed level of power that is nearly 50% lower than the current level, with cost savings to the tune of over $700 thousand yearly. Under *scenario 1* subscribed maximum power decreases by 9% and reduces costs by almost 5% yearly. Although the results are not to the magnitude of the maximum potential, the values are far from negligible. Even if most load fluctuations are reduced, some peaks might still exist and those peaks are what determine the reduction of the grid fee to the feeding grid cost. Along these lines, should the peak loads be reduced, optimizing the *grid fee to feeding grid costs* demonstrates a high potential economic gain for the distribution system operator. Even so, there exists a high risk for the operator in trying to capitalize on this potential.

	Scenario 1	**Scenario 2**	**Difference from maximum**
Optimized value (kWh)s for subscribed maximum power	38 499	19 770	-18 729
Decrease in subscribed maximum power (%)	8,99%	46,70%	37,71%
Annual difference in USD	$63.385,92	$701.608,64	$638.222,72
Annual difference in USD per customer	$4,80	$53,11	$48,31
Reduced annual cost (%)of subscribed maximum power	4,86%	46,23%	41,37%

Table 3: Simulation results for grid fee to feeding grid after the implementation of Demand Response

Ultimately, the current design of the feeding grid tariffs puts a high risk on the distribution operator while the feeding grid is reaping the benefits of a smoother load. At present, the *grid fee to feeding grid cost* is treated as an uncontrollable cost by the Swedish Energy Markets inspectorate in the

[19] Winter weekdays are defined as Monday to Friday, 06:00 to 22:00 in January, February, March, November and December.

remuneration. This means that the figures listed above will most likely accrue to the customer and not the DSO, once again giving little incentive to distribution operators when it comes to the implementation of demand response.

2.4 Postponing future investments

A distribution grid is comprised of a variety of components which include transformers, air cables and ground cables of several dimensions and types (Söder and Amelin, 1999) to aid in the transfer, transformation and distribution of electricity. Load typically varies throughout the day (as see in Figure 1) and as a result the grid is rarely used to its full capacity. Since the grid is technically capable of coping with extreme load flows its full potential remains untapped during times of normal consumption. As such, the grid is dimensioned according to the specifications of the load it needs to be capable of transferring (Albadi and El-Saadany, 2008). Current material capital assets are considered to be the actual grid capacity, along these lines Sala-Heby Energi Elnät AB has a current net worth of almost $22 million [20](PROFF.se, 2013; EI, 2011).

Investments into the distribution system can be divided into two categories: reinvestments and upgrade investments. Reinvestments replace current equipment at the end of their lifecycle (Mårtensson, 2013a). Upgrading investments aims to extend the capacity of the grid in order to cope with higher demand. Since assets have such long life cycles, such investments are often intertwined with each other (Mårtensson, 2013a). For instance, if a major power line is nearing the end of its lifetime, the DSO might choose to upgrade it to cope with future demand instead of merely replacing it. Like so, the average yearly increase in distribution assets is estimated at 1,6%[21] (PROFF.se, 2013). When simulating investments, the net present value (NPV) is commonly used. In essence, NPV sums up the present value of all the cash flows over the time which investments are active in the following manner:

Equation 9:
$$NPV = \sum_{i=0}^{n} \frac{C_i}{(1-p)^i} K$$

where n is the number of years for which the investment is valid, C_i is the cash flow for year i, p is the rate of discount and K is the initial investment. In this model, the initial investment is disregarded and thusly K is not used .The discount rate used is prescribed value by the Swedish Energy Markets Inspectorate at 5,2% for the regulatory period 2012 to 2015 period of supervision (EI, 2011). The distribution system operator provides a figure on how much the grid is expected to grow each year in order to calculate the time frame over which the NPV of the postponed investments can be estimated. If the growth of the network is stagnant or decreasing, no savings can be realized based on the assumptions of this model.

According to a study performed by Sweco (2010) for the Swedish Energy Markets Inspectorate, the current standard lifetime for distribution assets is 40 years. In the same report Sweco also suggests an increase in the standard lifetime of distribution assets by five to ten years (Sweco, 2010). This is one way to curb short term costs. Differently, it can be argued that the investments in the grid could be better utilized if the demand fluctuations are lowered. Literature (Bartusch et al., 2011; Skillbäck, and Ibrahim, 2012) suggests that the absence or postponement of future investments could lead to positive effects for the DSO as a direct effect of load management. More specifically, peak load shifting works to reduce load fluctuations and as long as extreme demand variations stay low, the grid which is dimensioned to withstand them can handle a higher overall amount of transferred energy.

[20] $21.438.240

[21] The average yearly increase in distribution assets was derived from historical values of material capital assets between 2009 and 2012 by averaging the yearly increase (PROFF.se, 2013).

The model assumes that the DSO's grid is dimensioned to handle the maximum load[22] possible, such that the ratio of load the grid needs to be able to withstand is directly proportional to the current maximum capacity. If the current maximum load is reduced, then the grid investment needed to cope with higher loads is nullified until the next time demand exceeds the maximum network dimensions. The savings in future investments are calculated based on these postponed investments. Demand response is modeled by the difference in maximum peak, between BLC and RLC:

Equation 10:
$$I^n = \frac{1}{E_{max,ratio}}$$

where I is the estimated average yearly increase in grid equity and n is the number of investment years load management can save. The postponed future investments in these years are then valued and discounted over the years n so that a net present value can be obtained. However, at the start a value for the postponed investments for each year must be established. The first postponed investment, i.e. the investment of year 0, is calculated as follows:

Equation 11:
$$C_0 = E_{max,ratio} * A$$

where C_0 is the value of the first postponed investments and A is the current material capital assets of the DSO. In order to properly reflect the ever increasing value of the investments, C_i is increased each consecutive year by I.

2.4.1 Simulation results of postponing future investments

	Scenario 1	Scenario 2	Difference from maximum
Difference in USD	$326.064	$7.320.640	$6.994.576
Postponed investment years	2	43	41
Difference per customer in USD	$24,68	$554,13	$529,45

Table 4: Simulation results for postponing future investments after the implementation of Demand Response

When initially looking at the results of the postponed investments component of the model, the figures seem staggering. It is important to remember that in order for the DSO to save anything from postponing investments there has to be a need to upgrade the grid to cope with rising demand. When looking at the maximum potential with a perfect load distribution, the grid would only need to be dimensioned to cope with half of the current demand. The net present value of this yields a reduction of almost a third of the current distribution assets with savings above $7 million. Under *scenario 1* savings accumulate to almost $330 thousand with 2 years of postponed investments.

3 Results discussion

When summarizing the results of maximum potential (*scenario2*), simply from power losses and grid fee to feeding grid optimization annual saving of over $880 thousand can be realized, approximately $67 per customer. Maximum savings from postponed future investments can also accumulate to over $7,3 million or $550 per customer. From *scenario 1* annual saving are above $100.000 or $7,8 per customer per year are achieved simply from the losses and feeding grid components. An additional savings of over $300 thousand or $25 per customer are available if

[22] In this part of the simulation, the actual maximum values are used as opposed to calculations dictated by the regional grid operator for subscribed maximum power calculated in equation.

investments are postponed, but the level of uncertainty here is quite high, due to the long time periods involved in the investments especially when considering the volatility of demand.

In order for the model to yield more accurate results, the implemented demand response program will have to be designed in more detail. This study was focused on designing a generally applicable model which illustrates the positive economic impact demand response can have for DSOs. The overall results indicate savings which cannot be neglected in the optimization of each factor (*power losses*, *grid fee to feeding grid costs* and *postponed future investments*) impacting the economics of distribution. Although the gains are relatively small in *scenario 1*, the optimum *scenario 2* serves as in indication of the maximum potential which leads to figures that are far from negligible for both distribution system operators and customers.

3.1 Lessons for future work

For the simulation we use data from Sala Heby Energi Elnät AB in order to analyze the economic impact of demand response for the distribution system operator. Nevertheless, it is important to emphasize that the model can be utilized for any DSO in Sweden inquiring further insight into the economic impact of DR implementation. Although not deeply considered in this simulation, it is undeniable that the Swedish climate varies enough to cause heavy irregularities in the load over seasons and in turn highly impact DSO remuneration. For instance, when comparing an average hour of January to the average hour in July of the distribution load curve, the problem becomes apparent. In January the average load is 29.760 kWh while the July average is a mere half at 15.534 kWh. This is largely attributed to the fact that Swedish households use electric heating. It is important to mention that Sala Heby Energi Elnät AB has seasonal fluctuations incorporated in its implemented demand response program (Sala Heby Energi AB, 2013; Sollentuna Energi AB, 2013). As a result, future simulations should consider seasonal variations in model design for load management stimulus.

What's more, the model does not consider the uncertainty in the amount of peak load that is shifted. The shifted load is evenly distributed throughout non-peak hours, which is something that rarely happens in practice. In fact, uneven distribution of load may lead to new peaks close to the turning points in a Time of Use tariff program (Parekh, 2013). For the model, the chosen level of peak load shift is 10%, based on figures for DR estimated or observed in electricity markets. It is uncertain if this value will be directly applicable to DSOs, thusly increasing the uncertainty of the impact demand response can have. Nevertheless, a 10% estimation serves as an achievable goal from consumers.

4 Conclusion

The above results indicate that under current conditions demand response savings can be achieved, but the magnitude is relatively low and the benefits only seen by the consumers. However, savings are still conceivable and therefore load management programs should not be neglected. The model may prove useful to Swedish DSOs implementing load management in the future since it provides a generally applicable way of examining what the positive economic effects may be following DR; something that has been hard to estimate before. The simulation also gives an indication as to how the different factors weigh against each other in effect. In the above simulation, *postponing future grid investments* had the highest savings per customer per year followed by *grid fee to feeding cost* and *power losses*. The total yearly savings for 10% demand response during peak hours is a little over $30 per year for each customer. These saving currently accrue to the customer and therefore DSOs have little incentive to engage customers in load management but if future regulation results in these saving per customer for the operator things might change. Further investigation is needed with respect to designing incentive mechanisms such that benefits are split between and DSO and the customer. In this way, incentives for load management will stimulate both consumers and DSOs to engage in demand response. Such mechanism design can be taken into consideration for the following period of regulation in tariff design by the Swedish Energy Markets Inspectorate.

Moreover, one interesting secondary effect that cannot be ignored from the simulation is that of price fluctuations on the spot market which serve to increase the potential yield from peak load shifting. This is not thoroughly researched in this work as the phenomenon was merely observed. Additional research may yield more accurate results on how this impacts the costs to DSOs via mechanisms designed from fixed tariffs, day-ahead prices, intra-day prices and even balancing. Additional exploration in comparing fixed pricing contracts and variable pricing contracts when compensating for losses (in an environment where demand response exists) may prove very useful for further insight into these gains.

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