MUNICIPAL THERMAL AND ELECTRICITY LOADS - A case Study in Linköping

Stig-Inge Gustafsson,
IKP/Energy Systems,
Institute of Technology,
S581 83 Linköping, Sweden

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Abstract

Linear programming models used for optimisation of various energy systems have received increased interest during the last ten years. One reason for this is the use of personal computers. Models with thousands of variables and constraints can now be rapidly optimised. If integers are introduced, which are necessary when increments or steps in cost functions are part of the model, the computing power is of even higher interest. However, many scientific authors do not discuss in detail how the model is designed and what basic data lie behind this design. This paper presents an attempt to study municipal thermal and electricity loads, and further how to divide data for one year into useful segments for linear and mixed integer programming purposes.

INTRODUCTION

In Sweden, many buildings are connected to district heating systems. Others use electricity for space, and domestic hot water, heating. Numerous buildings also use heating systems that have oil or firewood as primary sources of energy. It is natural that a proprietor tries to minimise the cost for this heating. The problem is that heating systems which can utilize cheap energy sources, such as heat from a heat pump, tend to be more expensive to buy and to install, while for instance a cheap electricity radiator must use expensive electricity in order to operate. There is therefore a problem of optimisation, i. e. how should different building-, heating- and ventilation equipment be combined when the total cost is to be minimised. The problem grows in complexity when also the utilities which produce e. g. district heat and electricity are included. If, for instance, the proprietor decides to add more insulation on the external walls of his building, this will affect the need for district heat and subsequently the possibility to produce electricity in the Combined Heat and Power, CHP, production plant.

The relation between the proprietor and the utilities is formalized in the form of an energy tariff. Many economists claim that this tariff should be based on the short range marginal cost of producing one more unit, or one unit less, of e. g. district heat or electricity. The cost for the risk of scarcity should also be included, see e. g. Reference [1] or [2]. In Sweden, where the peak load for electricity is supposed to occur during the winter, the highest price for electricity should also apply during these hours. During this peak the utilities must use oil condensing plants, or even gas turbines, in order to supply the consumers with electricity and thus the end user should be informed of these prices via the tariff. If the price is too high the proprietor will act in order to reduce his usage and hence the utility does not have to use so much expensive fuel. If everybody acts in such an rational economic way the mix between energy production and conservation would become optimal. This economic theory is, however, the subject for dispute and some researchers claim that the price should be based on the long term marginal cost instead, i. e. when the cost for new power stations etc. is included, see e. g. Reference [3].

MIXED INTEGER LINEAR PROGRAMMING

One method for optimising, i. e. finding the lowest cost for, energy systems is so called Mixed Integer Linear Programming, MILP. The original Linear Programming, LP, method has become more interesting during recent years because fast micro computers, or PCs, are readily accessible. One major drawback with the method is that the problem to be optimised must be purely linear. This is in part solved by introducing binary variables that can only take the value one or zero. The LP model then becomes a MILP problem. Another drawback is that an energy system, for example, must be divided into time segments in order to make it linear. For each such segment several variables must be used in order to find proper thermal sizes for all equipment in a building or a municipal energy system. The number of variables grows rapidly when these time segments get shorter. Too long segments, however, make the model too coarse and no trustworthy results comes out from the optimisation. The end user cost for electricity and heat is a result of the tariff which therefore is a perfect base for the time segments. This division in segments must, however, be used for the model as a whole in order to accurately describe the system in a mathematical way. More details of both LP and MILP models of energy systems can be found in e. g. References [4], [5] or [6].

TIME SEGMENTATION

As mentioned above the proprietor of a building is supposed to act according to the different tariffs which apply. In Linköping, situated about 200 km south of Stockholm, the tariff for electricity is based on three different levels. Marginal cost pricing is therefore not used. The high level is valid during working days from November to March between 0600 to 2200 and the energy cost is then 0.94 SEK/kWh, VAT and other taxes included. A medium level of 0.49 SEK/kWh applies for the same months but from 2200 to 0600 and for all weekends. From April to October the price is 0.38 SEK/kWh no matter the time, or type, of day. There are also other cost elements such as demand and subscription fees. Traditionally, this division into segments has been valid also when the utility bought electricity from the national grid, but in the now deregulated electricity market, spot pricing is likely to be more common. Because of the tariff at least three segments must be used. One for the high electricity cost, one for the medium and one for the low cost.

The district heating price is 0.26 SEK/kWh throughout the year. Also here certain other costs must be added. The district heating usage is highly dependent on the climate and the annual use is therefore split into the twelve months of a year. One way to reduce the cost for high priced electricity is to install a hot water accumulator. This accumulator should be charged during nights and weekends and discharged during working days. Because of the tariff, charging during the weekends can utilize a longer period of time, i.e. both Saturday and Sunday, while only eight hours are present during night time for week days. This might be important when the profitability for the accumulator is to be decided. We, therefore must treat weekends separately from other low cost periods.

From the above discussion it is obvious that at least 22 segments are needed. The winter months, November to March is each divided in three segments, one for high priced electricity, one for medium price electricity and one for weekends, due to the accumulator. This results in 15 segments. The summer months have one segment each which implies that 7 more segments must be used.

THERMAL AND ELECTRICITY LOADS

Linköping has about 130,000 inhabitants and about 80,000 of them live in the more densed part of the city. By help from the local utility Tekniska Verken in Linköping AB we have achieved monitored data on an hourly basis for the total loads of electricity and district heating for 1996 as well as outdoor temperatures for the same period. In Figure 1 the electricity load is presented and the first value, hour number 1, shows the number of MWh used between 00.00 and 01.00 for January 1, 1996.

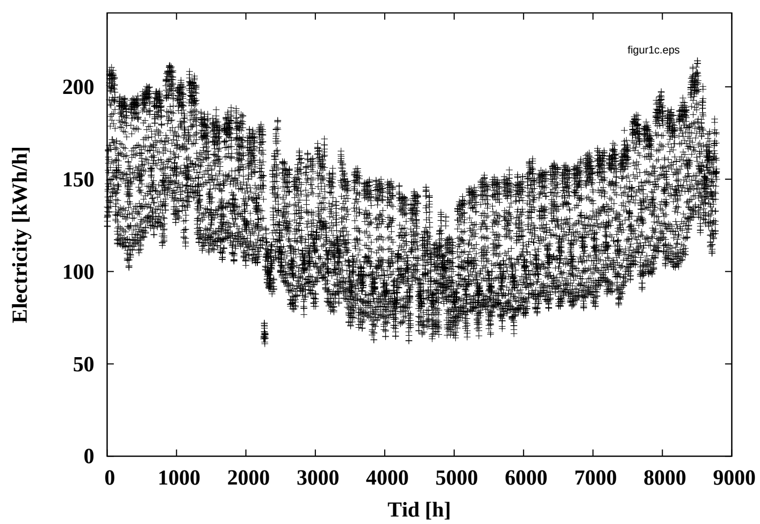

Figure 1: Electricity demand for Linköping, 1996

One full year, i. e. 8784 values are present in Figure 1 and the average demand seems to be about 130 MW. The peak load was about 214 MW, December 20 at 10.00, while the lowest value was approximately 61 MW, April 4 at 16.00. The influence of the climate is also obvious, but perhaps not as emphasized as suspected. Even in the middle of the summer when the climate is warm and the sun is up almost during the whole nights, the demand was about 60 MW. The district heating load is shown in Figure 2 and here the influence of the climate is still more pronounced.

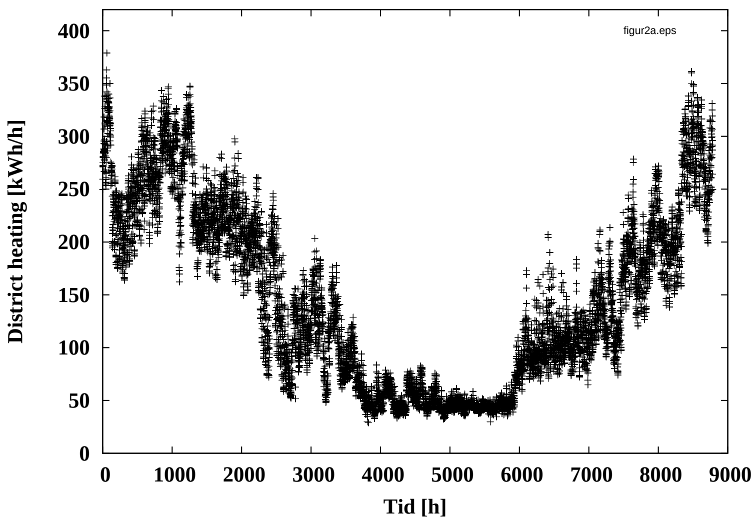

Figure 2: District heating demand for Linköping, 1996

The highest demand, 379 MW, was found for January 3, at 12.00, while the lowest value, 29 MW, emerged at June 8 at 12.00. It shall be noted here that the true maximum demand is 420 MW but a few of the district heating plants have not been included in the monitored values. Interesting to see is also the variation of the outdoor climate which is found in Figure 3.

The highest temperature + 28 °C occurred at June 8, 14.00, while the lowest temperature, - 20 °C was found for February 18, 07.00. There was therefore not a precise connection between the maximum demand and minimum outdoor temperature. The overall behavior, however, shows that the climate has a significant role for the demand of both electricity and district heat. Another way to depict the demand is to use a duration graph, i. e. to sort the values in descending order. The winter will then be located to the left, and the summer to the right in such a diagram. Figure 4 and 5 show this for electricity and district heat respectively.

In Figure 4 the duration graph for the electricity demand is shown. Once again it is obvious that the base load, with a very long duration, is about 60 MW. The curve follows almost a straight line up to about 150 MW when the increase gets steeper. However, the peak is not very accentuated.

A more obvious peak can be found in Figure 5 where the duration graph for the district heating system is shown.

The base load has also a much lower level and the curve therefore has a

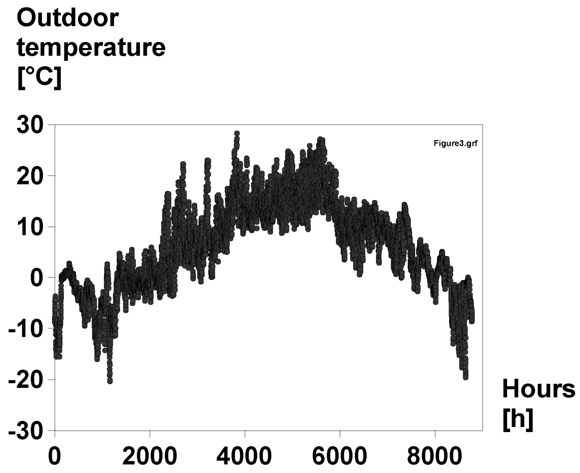

Figure 3: Outdoor temperature in °C for Linköping, 1996

steeper slope.

The duration graph for the outdoor temperature, see Figure 6, is constructed as a difference between the highest outdoor temperature, about 29 °C and the actual temperature.

The reason for this is because the graphs will then have similar shapes.

The district heating and electricity loads must now be implemented in the mathematical models. Because of the tariffs for district heat and electricity and the possible use of the hot water accumulator it seems suitable to use the same time segments for the loads as used for the tariff. A small computer program has therefore been elaborated to sort the load in these segments. The result is shown in Table 1.

From Table 1 it is obvious that some of the finer details in the duration graphs, Figures 4 and 5, disappear. For instance the highest peak in Figure 4 is about 210 MW while the corresponding peak in Table 1 is only 188 MW, see the February high cost segment. The same thing could be found for the district heating load. The peak in Figure 5 is about 350 MW while 277 MW can be found in Table 1. One problem with the loads is that they do not follow each other in a perfect order. The third largest value for the electricity load can be found in the December high cost segment while the third largest value for the district heating load is in the February medium cost segment. When a model is designed it is important to maintain the distribution of the time segments. Further, the main interest when a CHP plant is built is the electricity production and therefore the load is sorted so that the electricity load is arranged in a descending order while the district heating load follows the corresponding electricity segment order. Such a graph, based on Table 1, is found in Figure 7.

If the district heating load was about three times the electricity load a CHP plant would have been an ideal proposition. This because about three times

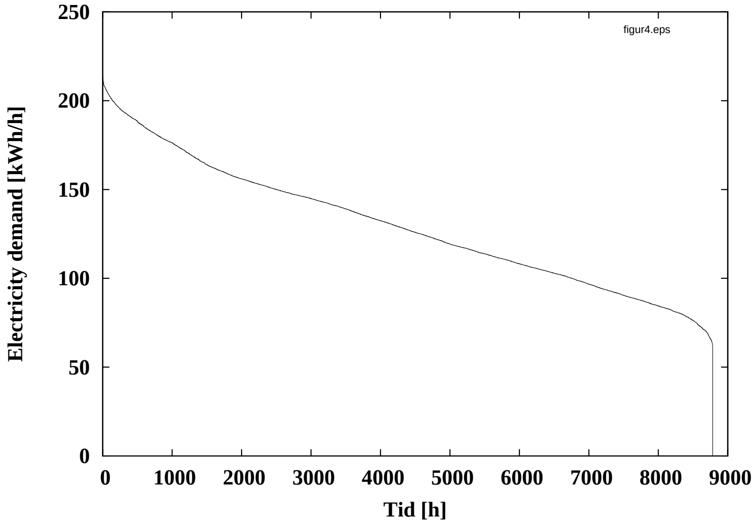

Figure 4: Duration graph for the electricity demand in Linköping, 1996.

more heat than electricity must be produced in such equipment.

From Figure 7 it is obvious that this is not the fact. Sometimes the district heating load is twice the electricity load but during the summer the opposite is valid, i.e. the electricity load is larger than the district heating load.

Above it was mentioned that the finer details of the two loads disappeared when they were sorted in the 22 time segments. The MILP models are used for optimisation, i. e. they result in a minimised cost for the system. This cost in part depends on the sources for electricity and heat that are used. For a municipal electricity system the peaks are almost always covered by use of purchased electricity from the national grid while the peak in district heating is covered by use of oil fired boilers. The energy cost for the peak is therefore known and hence the loads in Figure 7 could be used. However, there must be equipment which have sufficient power for covering also the worst situation. When electricity is of concern costs emerge in the form of demand charges while expensive oil fired oil boilers must be used for covering district heating peaks.

The demand charges are frequently based on a mean average value of the demands for one hour during each high cost segment. In our case this leads to examining five values, one for each month from November to March. The values for Linköping, 1996, are shown in Table 2. Because of the now deregulated electricity market in Sweden we do not know the exact design of the demand charges but probably a mean value of the demands in Table 2, i. e. 205 MW, will be sufficient for a MILP model. There is also a subscription fee based on the absolute maximum demand, i.e. 214.1 MW.

The maximum district heating demand, 378.9 MW, was found for January 3, at 12.00.

If the MILP model is to be used as a basis for future investments it is not enough to study just one specific year but instead a number of years for a long period of time. However, with all other uncertainties in mind the fluctuations of the electricity and thermal loads might be of minor interest if not an extremely

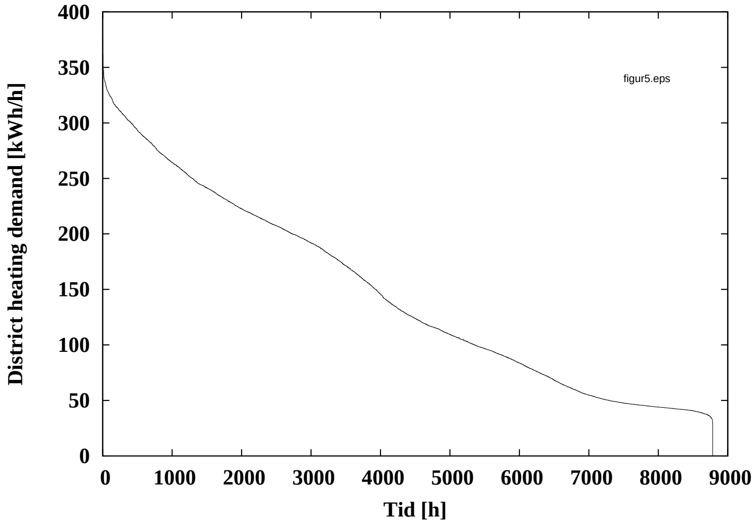

Figure 5: Duration graph for the district heating demand in Linköping, 1996

mild, or cold, year is used as a base for the model.

CONCLUSIONS

We have shown how monitored data for one electricity and one district heating load are split up in smaller segments for use in LP and MILP models. The base for the segmentation is the applicable tariffs used by the utility and the producers and owners of the national grid. The electricity tariff is divided in high, medium and low cost periods while district heating has the same price throughout the year. Both the monitored loads show, however, a strong influence of the climate and therefore each month is an applicable basis for the segmentation. The use of a hot water accumulator makes it necessary to keep apart weekends during the winter period from other medium cost periods. This results in 22 separate segments. One drawback with this method is that finer details of the peaks disappear. Adding some very short, one hour, segments solves this difficulty. At least one such segment should be added for the district heating load while two or more segments must be used for the electricity load.

It is also important to use the same segments for electricity and district heat. For Linköping it is shown that the district heating load is about twice the electricity load in some segments while about half, in others. This might have a significant influence on the possibilities to use CHP.

ACKNOWLEDGEMENT

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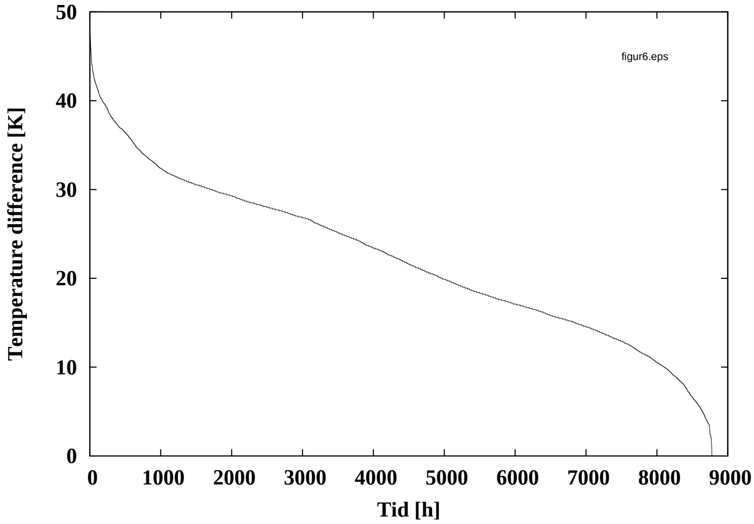

Figure 6: Duration graph of the difference between the highest monitored outdoor temperature and the actual temperature

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Month	Segment	Hours	Electricity		District heating	
		[h]	Demand [MW]	Energy [GWh]	Demand [MW]	Energy [GWh]
Jan.	High cost	368	184.8	68.0	265.4	97.7
	Medium cost	184	132.6	24.4	235.2	43.3
	Weekends	192	140.4	26.9	235.5	45.2
Feb.	High cost	336	187.7	63.0	276.6	92.9
	Medium cost	168	142.3	23.9	263.5	44.3
	Weekends	192	144.3	27.7	259.3	49.7
Mar.	High cost	336	168.5	56.6	220.5	74.1
	Medium cost	168	124.1	20.8	213.8	35.9
	Weekends	240	126.8	30.4	210.7	50.6
Apr.	Low cost	720	121.0	87.0	136.2	98.0
May	Low cost	744	115.8	86.0	110.2	81.9
Jun.	Low cost	720	103.8	74.6	52.3	37.6
Jul.	Low cost	744	100.2	74.5	50.9	37.9
Aug.	Low cost	744	106.8	79.4	44.8	33.3
Sep.	Low cost	720	116.0	83.4	93.1	66.9
Oct.	Low cost	744	125.7	93.3	119.0	88.4
Nov.	High cost	336	167.8	56.4	188.5	63.3
Nov.	Medium cost	168	113.3	19.0	166.1	27.9
Nov.	Weekends	216	120.5	26.0	162.5	35.0
Dec.	High cost	352	176.4	62.1	254.8	89.7
Dec.	Medium cost	176	129.3	22.6	225.8	39.5
Dec.	Weekends	216	140.6	30.4	244.3	52.8

Table 1: Electricity and district heating load for the 22 time segments

Time	Demand [MW]
January 3, 16.00	210.5
February 7, 10.00	211.6
March 15, 11.00	188.7
November 28, 15.00	197.4
December 20, 10.00	214.1

Table 2: Maximum electricity demand for the winter months in Linköping, 1996

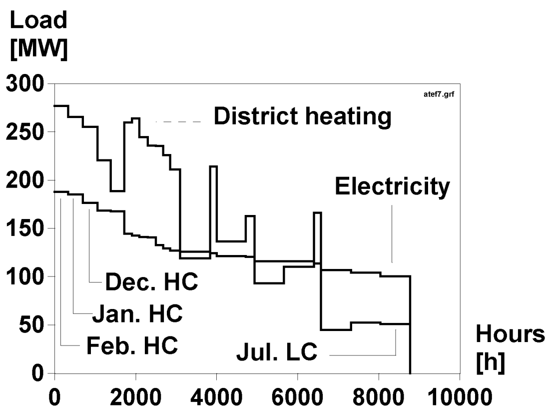

Figure 7: Electricity and district heating loads for Linköping, 1996. The electricity load is sorted as a duration graph