PN-ABS-107

RESOURCE MANAGEMENT ASSOCIATES
of Madison, Inc.

SUBCONTRACTOR REPORT

A NEW ELECTRICITY TARIFF DESIGN IN THE LITHUANIAN POWER SYSTEM

Prepared by
M. Krakauskas, Lithuanian Energy Institute
G. Volskis, Lithuanian State Power System

Prepared for
RESOURCE MANAGEMENT ASSOCIATES OF MADISON, INC.

DECEMBER 1992

BEST AVAILABLE DOCUMENT

USAID EMERGENCY ENERGY PROGRAM
FOR EASTERN AND CENTRAL EUROPE

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PREFACE

The work in this report is being carried out within the framework of the U.S. Emergency Energy Program for Eastern and Central Europe and the Baltic Republics under a Resource Management Associates of Madison, Inc. (RMA) contract with the U.S. Agency for International Development. RMA, as Prime Contractor to USAID, is currently implementing the Energy Pricing Reform Project and the Industrial Energy Efficiency Project in Romania, Czechoslovakia and Lithuania. The report is one of a series describing the activities, results and recommendations of the projects.

The report, entitled "A New Electricity Tariffs Design for the Lithuanian Power System" is one of a series of four papers written by Lithuanian subcontractors. The study was done by Lithuanian energy analysts with limited guidance from the RMA. The authors are M. Krakauskas and G. Volskis, are at the Lithuanian Energy Institute and the Lithuanian State Power System respectively.

The report demonstrates that the energy analysts for the Government of Lithuanian are well on their way to conceptually understanding the structure of and methods used to determine electric tariffs in the USA. The study is an interesting analysis of the structure of the Lithuanian power system's costs and tariffs. The most important aspect of this study is the marginal cost evaluation of Lithuania's power production.

This is a working document published informally by RMA. To present the results of the project with the least possible delay this report has not been prepared in accordance with procedures appropriate to our formally printed documents. The report was not edited and received only very light review by RMA. Comments were made on the first draft of the paper. RMA does not necessarily endorse the views expressed or the findings presented in the text. The document's subject matter warrants its distribution.

ABSTRACT

A NEW ELECTRICITY TARIFF DESIGN IN THE LITHUANIAN POWER SYSTEM

by M. Krakauskas and G. Volskis
December, 1992

LPS (Lithuanian Power System) consists of one generating utility and seven distribution utilities, all operating as monopolies. Currently variable costs (predominately fuel) account for about 90% of expenses. The generating utilities sell energy to the distributing companies and the distribution companies set prices dependent on usage and capacity. Although cost differ, prices are uniform across the distribution utilities. Inter-utility electricity sales are priced in such a manner that profits are equalized. Thus price does not reflect true costs. Industrial capacity charges are applied only when a firm exceeds their normal operating capacity by a factor of two. Industrial consumers subsidize the electric prices of the residential sector, particularly the rural residential sector. The current structure of the electrical system offers no economic means for the residential sector consumer to reduce consumption. Distribution companies profits are based on sales volume, thus here is disincentive for energy conservation. The generating utility operates at an even load, not varying with demand. Excess production (mainly at off peak times) is exported at contracted prices (which are below marginal costs). Electricity export prices are dependent on interstate contracts with Belarus and Kaliningrad. In the Baltic region, base electricity sellers are Lithuania and Estonia the peak seller is Latvia.

This paper proposes and calculates cost-based electricity tariffs, based on Western models. The authors suggest that 70% of the average costs of the distributing companies are related to usage and 30% related to capacity (i.e. 30% of all costs should be recouped by capacity charges). Currently, with demand falling, there is excess capacity, thus the marginal cost of increasing demand at peak is very low.

The authors apply marginal costing to asses the Lithuanian power generation structure. The Elektrenai thermopower plant, cogenerators, and the Kaunas hydropower station are possible marginal generators. Marginal fuel cost calculations suggest that the pumped hydro-storage power plant is preferable to using cogeneration plants in condensate operation (i.e. operating cogenerators as power only). The authors recalculated tariffs using international fuel and capital costs, and applied Western accounting practices (charging for depreciation, and return on capital) and found the recalculated tariffs to be 160% of the current tariffs (6.1 and 10.4 talonas/kWh respectively).

In the report the authors make several recommendations. Price must be determined according to costs on a usage and capacity basis. Subsidies between distribution companies and between endusers (residential subsidized by industrial users) should be eliminated. Utility incentives structure should encourage conservation; the rate of return should be increased for utilities making demand side investments. Taxation should not be based on capital but on energy production. Fixed costs should be assessed for five consumer groups: rural, retail, urban, industrial (low tension) and industrial (high tension), and levied

accordingly. Independent small energy producers should be encourage to enter the market. Off peak electric production beyond Lithuanian requirements should not be exported but converted to pumped storage and sold at peak times for export.

ERRATA

General:

1. Rubles and talonas are used interchangeably in the text of the report. The Lithuanian currency was officially changed from the ruble to the talonas on October 1, 1992. In December of 1992, the exchange (selling) rates were 284.2 rubles/ US$ and 0.8 talonas/ruble.

Page Specific:

Page	Comment
5	The graph, figure 2, is not normalized.
6	Caption on table 1 "increase in prices (SUR/kWh)" SUR refers to Soviet Union Ruble. The six columns are for six time periods in 1991 and 1992.
21	In the first sentence, the figure referred to is figure 11.
26	Figure should be labeled figure 14.
42	Table 18, the value for the "return on capital" column for scenario "III", should be 19500 not 195000.

Energy Price Reform Working Group
Government of Lithuania

A NEW ELECTRICITY TARIFFS DESIGN IN THE LITHUANIAN POWER SYSTEM

Prepared by
M. Krakauskas LEI
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Under contract with Resource Management Associates, Madison, Wisconsin, U.S.A.

K a u n a s 1992

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1. *The present situation*

The Lithuanian power system consists of seven electricity distribution utilities and one energy generating utility. There are two levels of electricity purchase and sale. In the wholesale level the power generating utility sells energy to the electricity distribution utilities. In the retail trade electricity is sold to consumers. In the wholesale trade the only good to be sold is energy, in the retail trade - capacity and energy.

Under the state requirement there are equal electricity prices in all the distribution utilities without taking into account different production costs. It makes some utilities profitable and some - unprofitable. In order to equalize their profits the wholesale trade is organised so that all the distribution utilities become equally profitable. It requires the lower energy purchase price for utilities operating with higher costs. In this case energy price doesn't reflect production costs, and creates incorrect relations between different economical measures. In fig. 1 the existing system of economical measures in diferent dispatching utilities is shown.

The existing tariffs system consists of a charge for an energy consumed and a charge for a required capacity during the maximal load of the energy system. Energy prices are not compatible with correspondant costs. Hence one group of energy consumers subsidize the other consumers group (tab. 1).

One could find that energy consumed in a residential area is the cheapest but it doesn't correspond with real production costs as load curve is a very uneven (fig. 2). Industrial consumers are paying tariffs exceeding energy production costs.

A required capacity charge for industrial consumers with an installed capacity more than 750 kW doesn't stimulate a consumer to decrease its capacity because a lower load capacity isn't measured. According to the last years contracts the required capacity exceed the real capacity twofold. So this parameter doesn't regulate consumption level.

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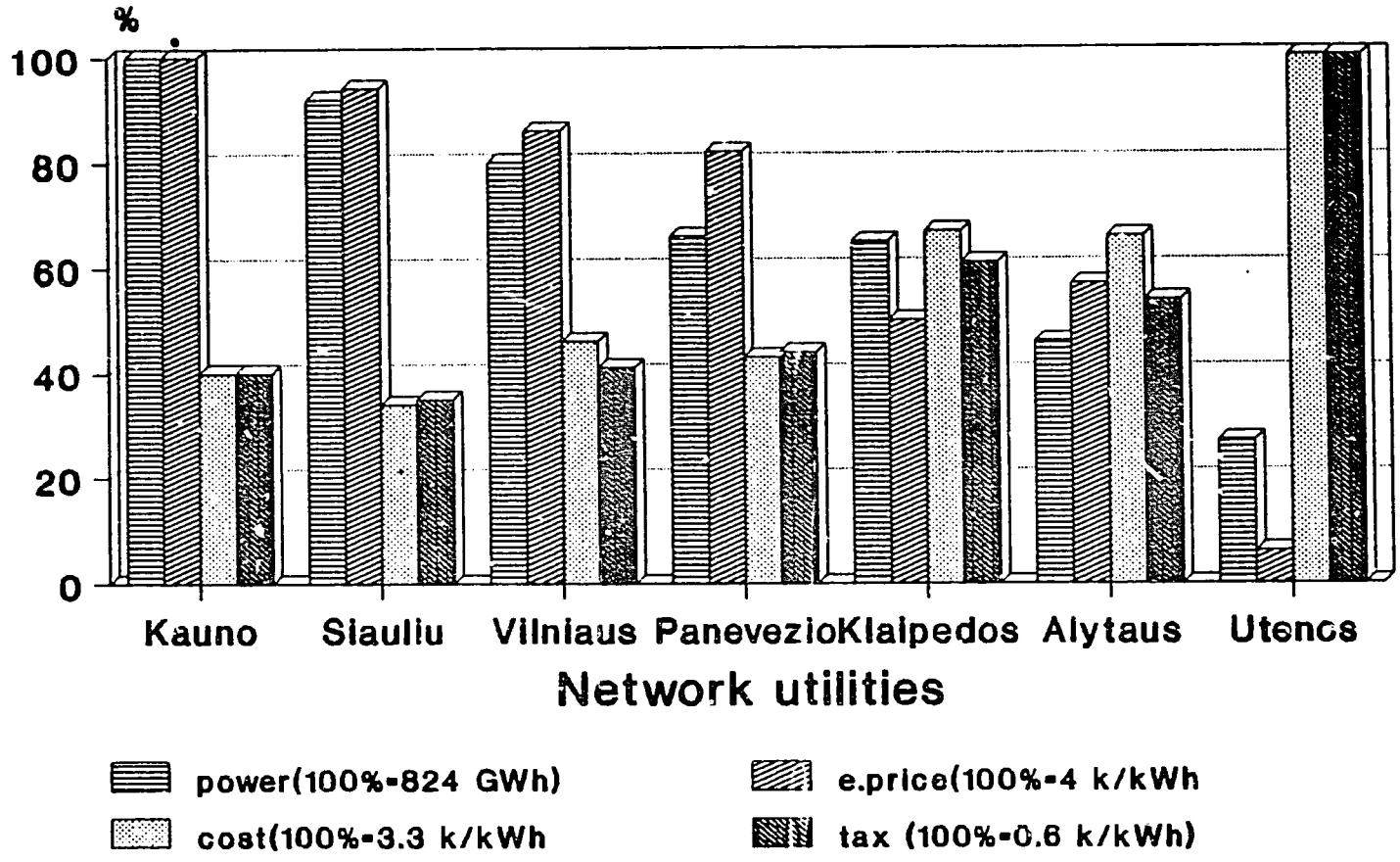

Fig. 1. The main indicators of electricity network utilities, end of 1991

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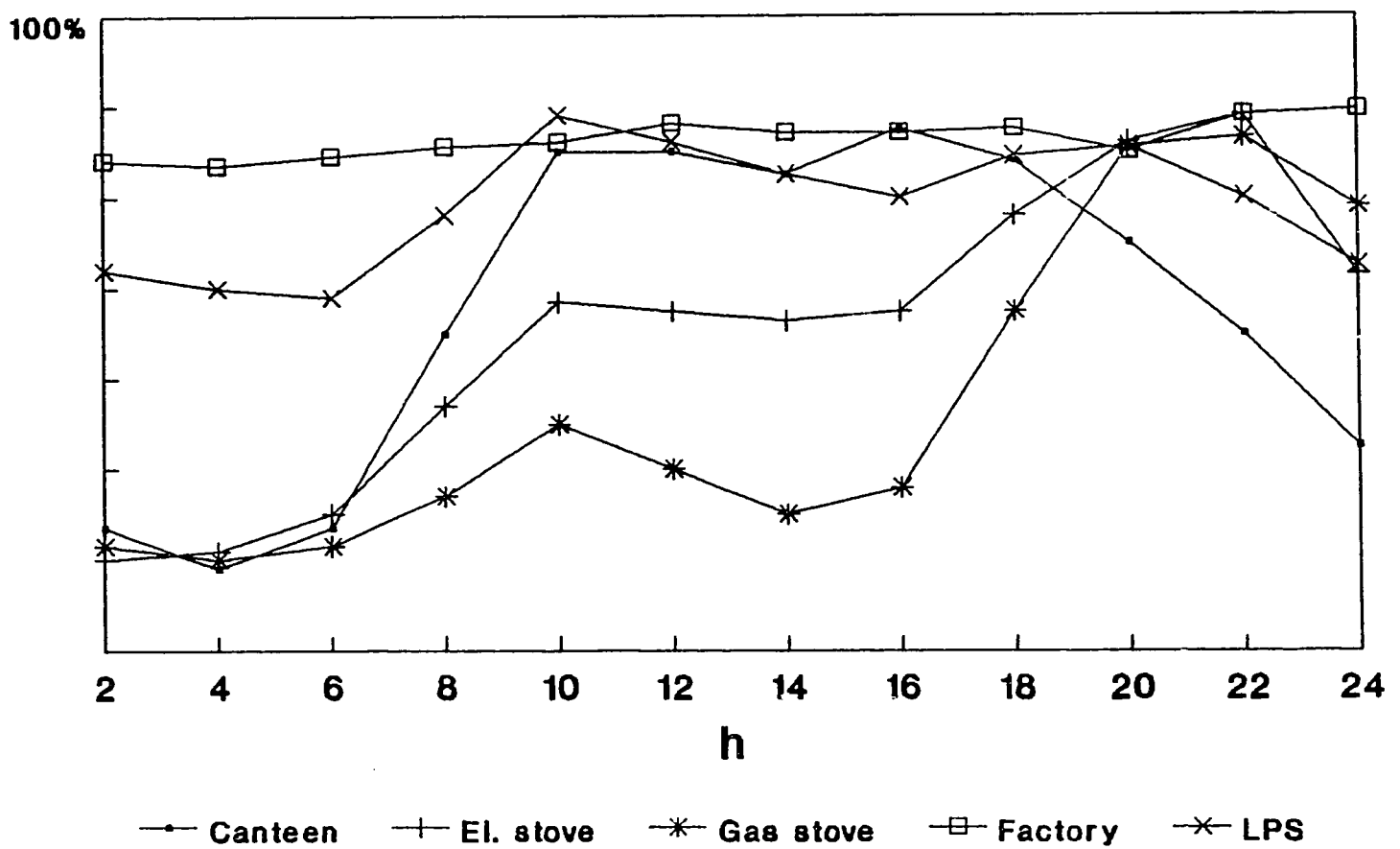

Fig.2. Normalized demand curves

Table 1

Increase of electricity prices for different consumer groups

Energy consumers	Increase in prices (SUR/kWh) 1991-1992					
	1	2	3	4	5	6
Residential	0.066	0.35	0.5	0.7	3.5	5.4
Residential during night	-	-	0.25	0.35	2.0	3.0
Energy storage equipment	0.03	0.16	0.25	0.35	2.0	3.0
Small industry	0.06	0.50	1.50	2.00	3.5	5.8
Large industry:						
capacity charge					160	250
av. energy charge	0.038	0.42	1.1	1.4	3.3	5.2
night en. charge	-	-	-	-	2.0	3.0
middle en. charge	-	-	-	-	3.5	5.8
peak energy charge	-	-	-	-	4.5	8.0

Defficiency of the existing tariff system are different energy charges according to different groups of consumers. A consumer has no economical tools to reduce energy consumption and correspondant expenditures in the system.

Furthermore, every state utility is profit seeking, and its profit depends on the amount of energy sold. An application of this principle at an energy distribution enterprise is especially serious hindrance to energy conservation, as a supplier isn't interested in energy saving at a consumers side.

Though there was created a number of independent utilities in the power system, in practice one monopoly was substituted by several ones. There could be no competition among the utilities, while they were established instead of former power distribution network enterprises which were natural monopolies. Energy generation, where competition could be introduced, is still supervised by the state enterprise "Lithuanian power system". So the Lithuanian power system is operating as a monopoly, and

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Lithuania even has no antimonopoly law*. Such an energy market is rather complicated and the pricing system isn't clear.

So a reform of economic relations in thepower system is needed. Implementation of market relations in the power system should be the main aim looking for an optimal energy pricing.

2. *Improvement of energy purchase and sale process*

Improvement of an energy purchase and sale process must be connected with organization structure of the power system. The pricing system must assure independance of formally independant electricity distribution utilities and encourage process of decentralization. Hence energy price must be determined according to its cost at the correspondant utility.

Energy purchase and sale process could stay at two levels: a wholesale trade and a retail trade. In a wholesale trade producer sells electricity to an independant distribution utility and in a retail trade - distribution utilities sell electricity to consumers. Though in the first stage one couldn't chose a producer, the pricing system should encourage independant small energy producers. Time by time they could be competetive with the large-scale producers.

In the wholesale trade the existing principle when energy sale price depends on buyer costs must be changed. Energy price must depend on producer costs. A new pricing system should reflect all the systems costs. In order to cover total costs the correspondant price system should be established.

3. *Structure of tariffs*

Structure of tariffs must encourage both energy producers and energy consumers to create an optimal operation of the power system. The tariff system must help to remove now existing the following problems:

- industrial consumers subsidize residential consumers*,

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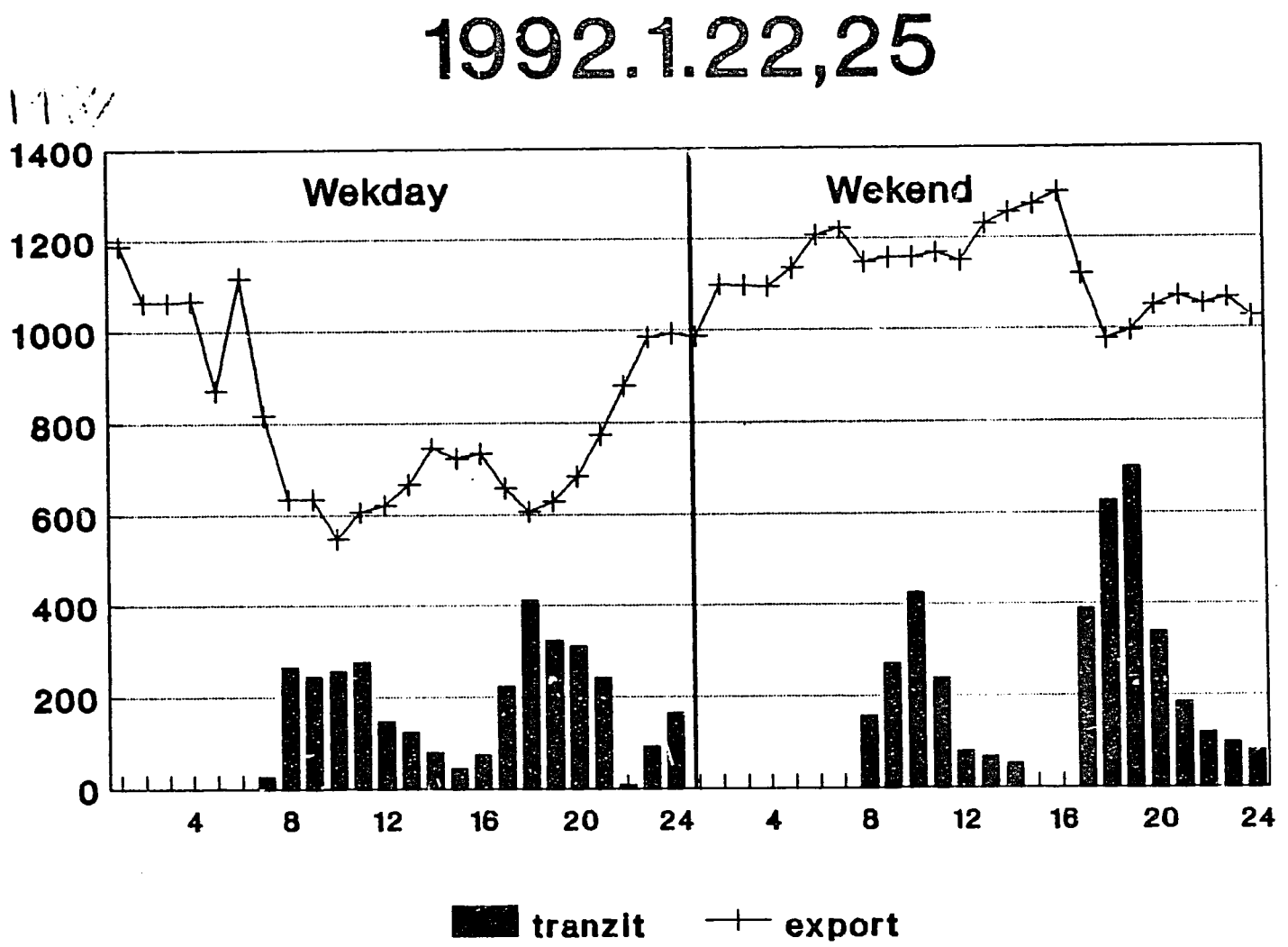

fig 3 Export and tranzit

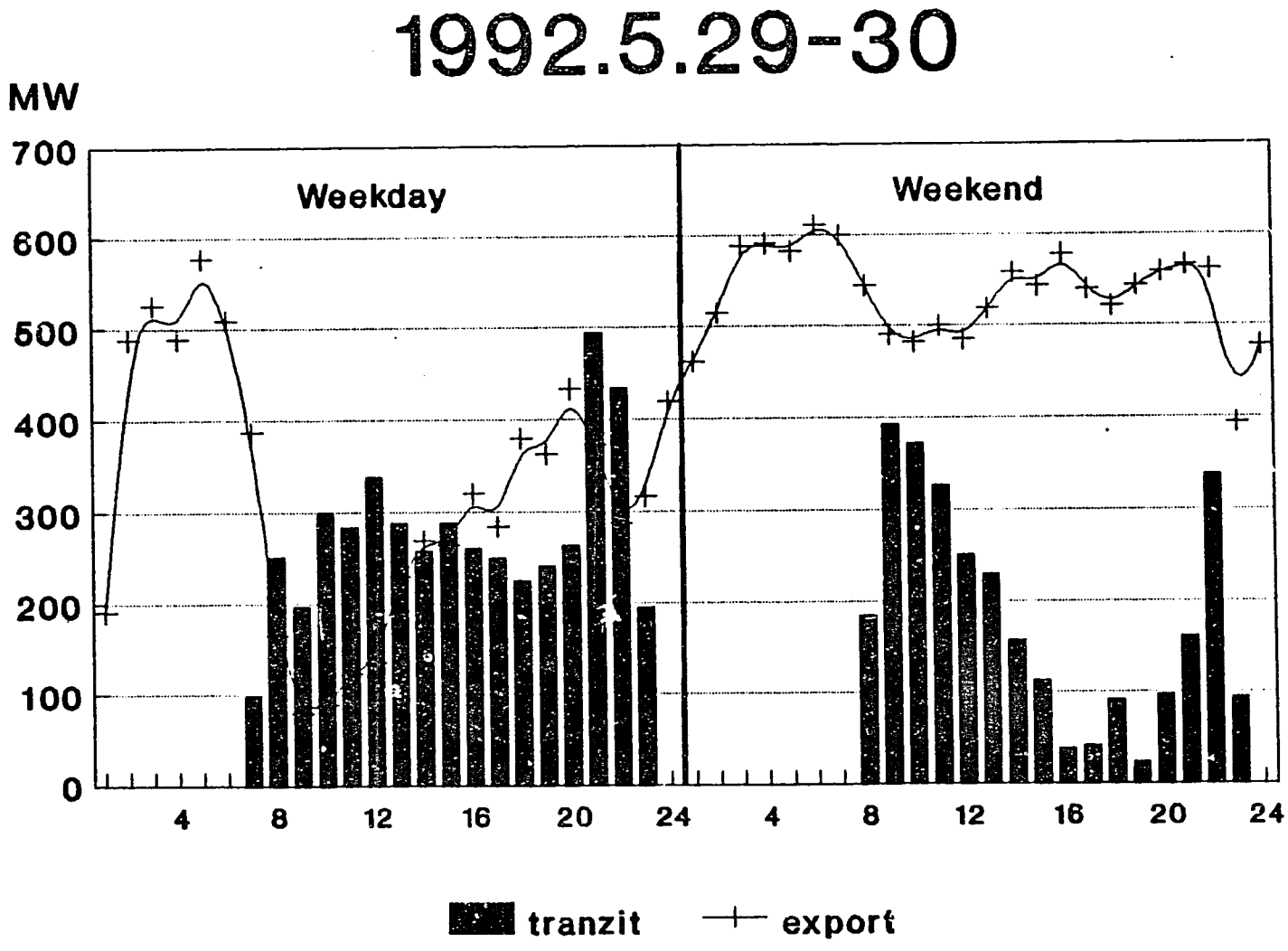

Fig.4 Export and tranzit

- some electricity distribution utilities are subsidizing the other electricity distribution utilities,

- system of profit seeking for energy utilities doesn't stimulate energy savings,

- cheap minimal load energy isn't used sufficiently in Lithuania and sold abroad (fig 3,4)

- cheap minimal load energy is sold abroad instead of using it in pumped storage hydropower station to convert it into a more expensive peak energy for export.

Some of these problems could be solved if tariffs were oriented into covering all the costs in the power system.

Costs in the power system depend on conditions of energy consumers. There are several cost categories:

- constant power plants costs,
- constant network costs,
- variable power plants costs,
- variable network costs.

Different costs are conditioned by different consumer factors as:

- type of consumer,
- consumers maximal capacity,
- energy consumed.

Relation between power system operation costs and consumer factors is shown in fig. 5. A value of cost depends on intensity of consumer factors. So the factors must be characterised by measured parameters or evaluated by some method.

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* - just changed

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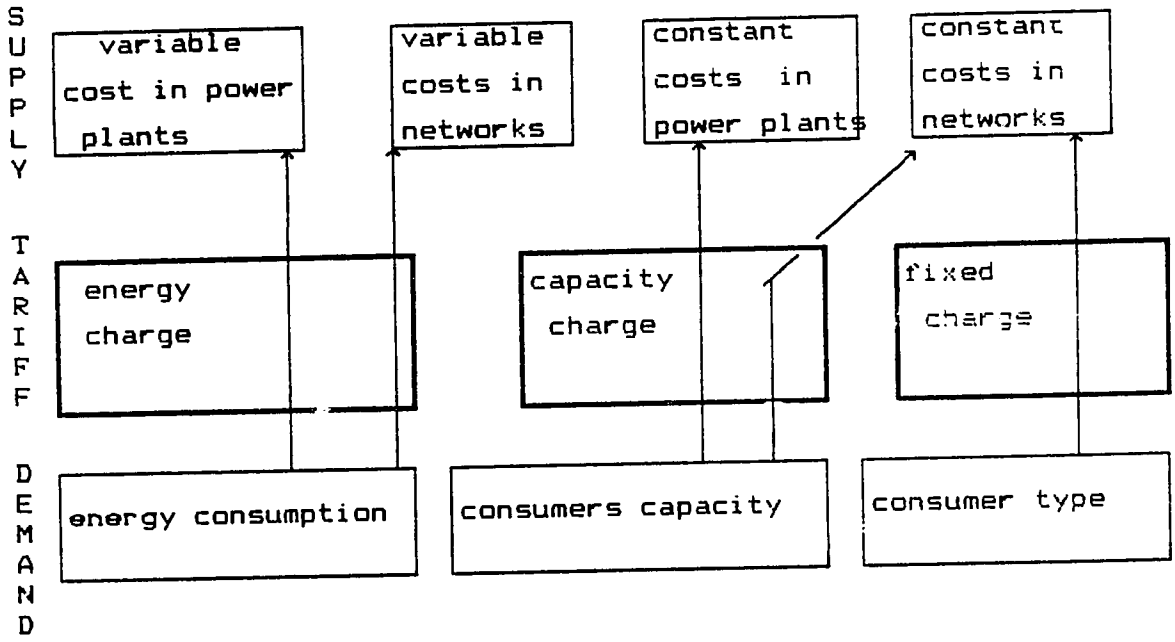

Fig. 5. Relation between power systems costs, consumer factors and tariff structure

A type of consumer could be characterised according to: continuity of energy supply, controllability from the power system, level of a nominal tension. These parameters aren't measured, they are evaluated.

A consumers capacity is characterised by the required capacity during maximal load of the energy system (P_{sm}) and the required maximal capacity (P_m). These parameters could be measured.

Consumer must pay his energy bill according to these parameters. Hence a new tariff system could be as follows:

$$M = m_f + m_c * P_m + m_l * E_l + m_m * E_m + m_p * E_p \qquad (1)$$

where M - payment for energy supply,

m_f - fixed charge,

m_c - charge of required capacity at the peak time,

m_l - energy charge at the low demand time,

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m_m - energy charge at the middle demand time,

m_p - energy charge at the peak demand time,

P_m - required capacity at the peak time,

E_l, E_m, E_p - used energy at the low, middle and peak demand.

This system will enable a consumer not only to cover all the system operation costs but also to regulate its own consumption diminishing expenditures as also overall costs.

Such a tariff system is rather complicated and needs a sophisticated account. Hence during the transitional period the simpler system should be implemented. Simplification of the system leads to a reduction of the number of componenets. Possible simplifications are:

$$M_1 = m_{17} * W, \tag{2}$$

where $m_{17} = M/W$, $W = \Sigma E_i$,

$$M_2 = m_2 + m_3 * W, \tag{3}$$

where $m_8 = m_f + m_c * P_c$, $m_3 = (m_l * E_l + m_m * E_m + m_p * E_p)/W$,

$$M_3 = m_4 * P * m_5 * W, \tag{4}$$

where $m_4 = (m_f + m_c * P_c)/P_c$,

$$M_4 = m_4 * P_c + m_l * E_l + m_m * E_m + m_p * E_p, \tag{5}$$

$$M_5 = m_f + m_l * E_l + m_m * E_m + m_5 * E_p, \tag{6}$$

where $m_5 = m_c * P_c / E_p + m_p$

$$M_6 = m_f + m_l * E_l + m_6 * E_{mp} \tag{7}$$

where $m_6 = (m_m * E_m + m_p * E_p)/(E_m + E_p)$

4 Diferentiation of energy acording to tariff structure

Planing income from sold energy acording to different tariffs requires some detalization of total used energy over a period. This detalisation should be provided according to a tariff structure shown in fig. 6, 7, 8, 9. From analysis of energy consumption characteristics were concluded the following relations:

winter energy consumption share is 65% of annual consumption,

summer energy consumption share is 35% of annual consumption,

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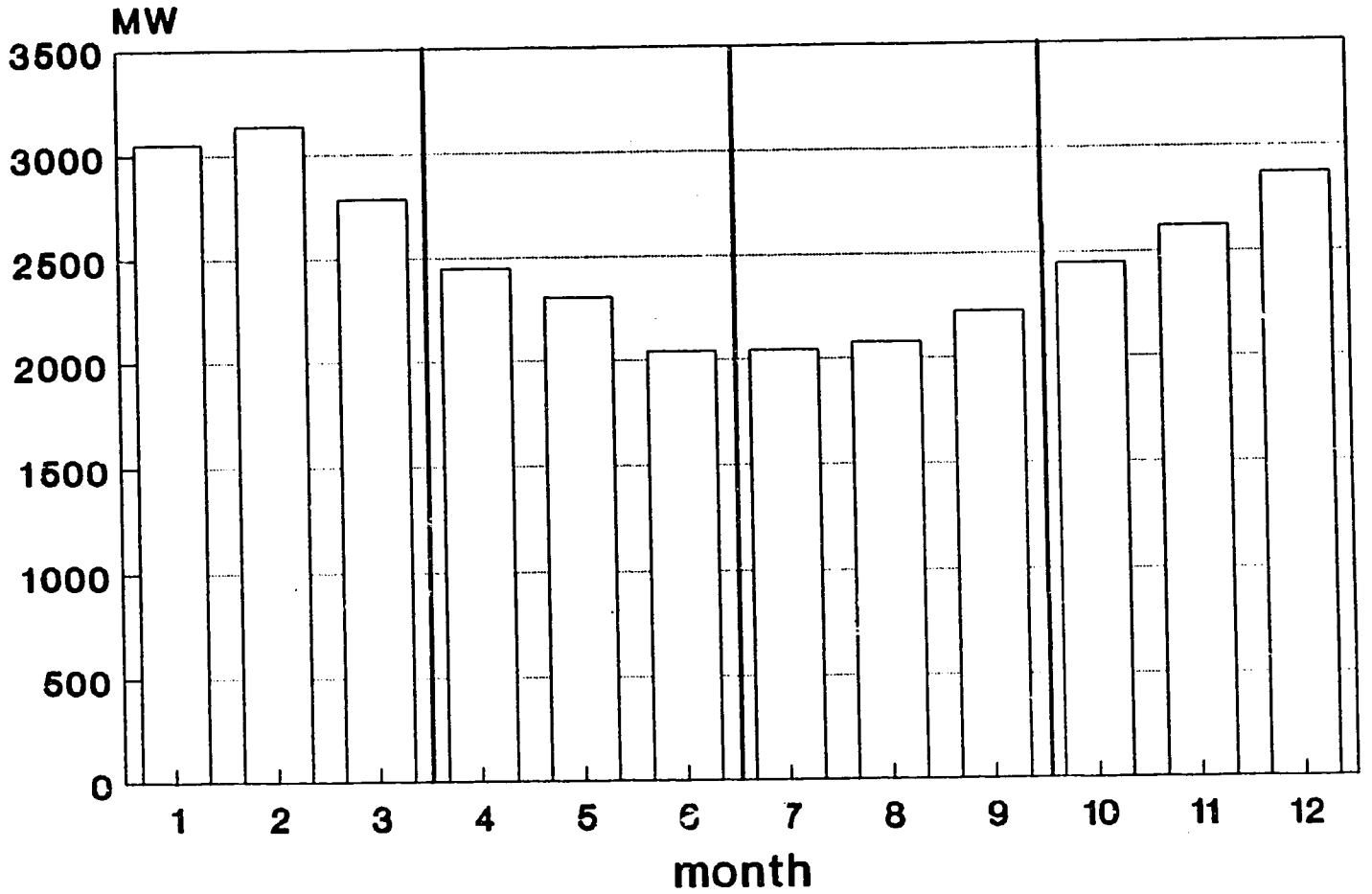

Fig.6 Maximal Load over the 1991 year

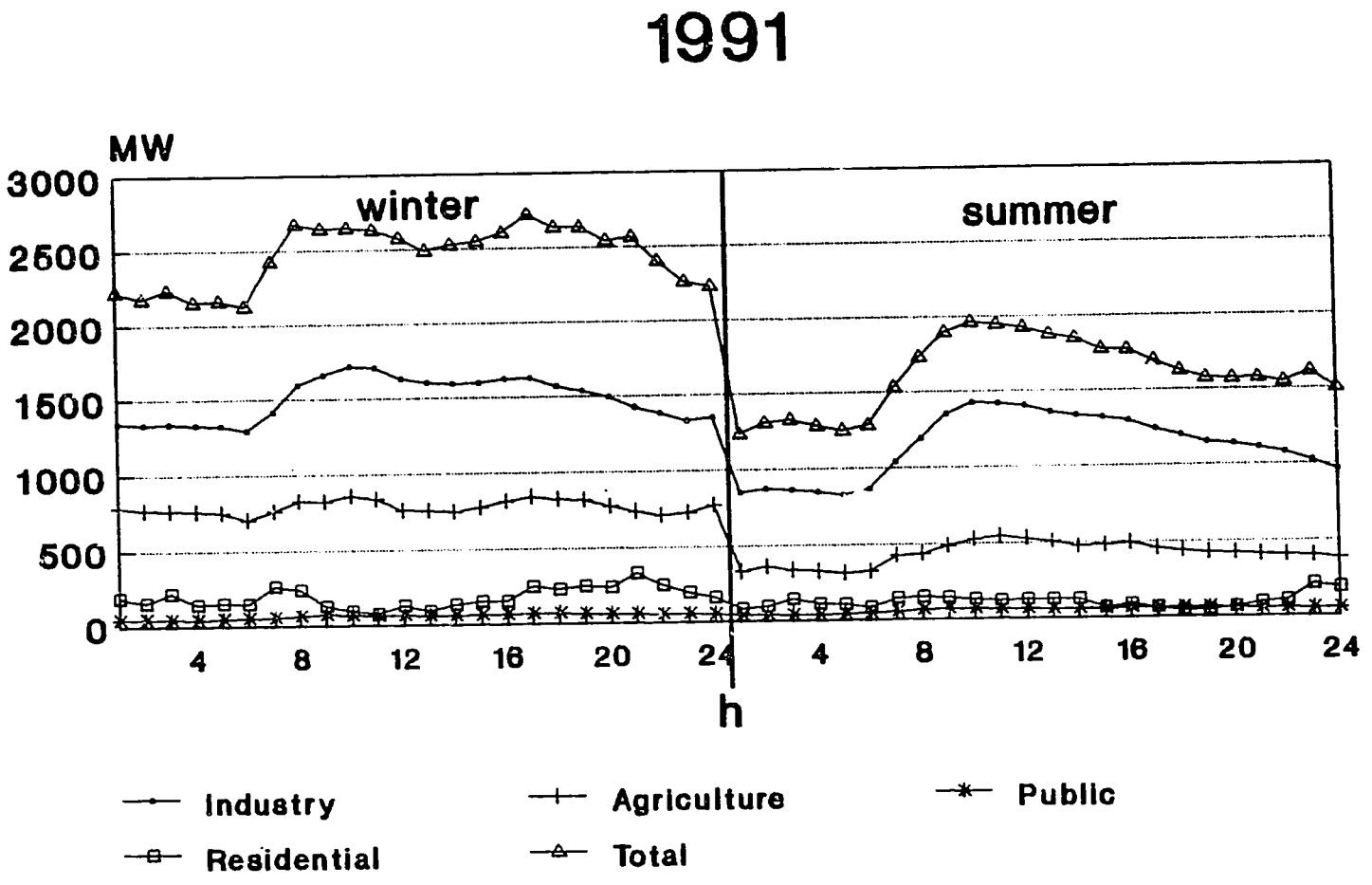

Fig.7.Load of seasonal electricity consumption

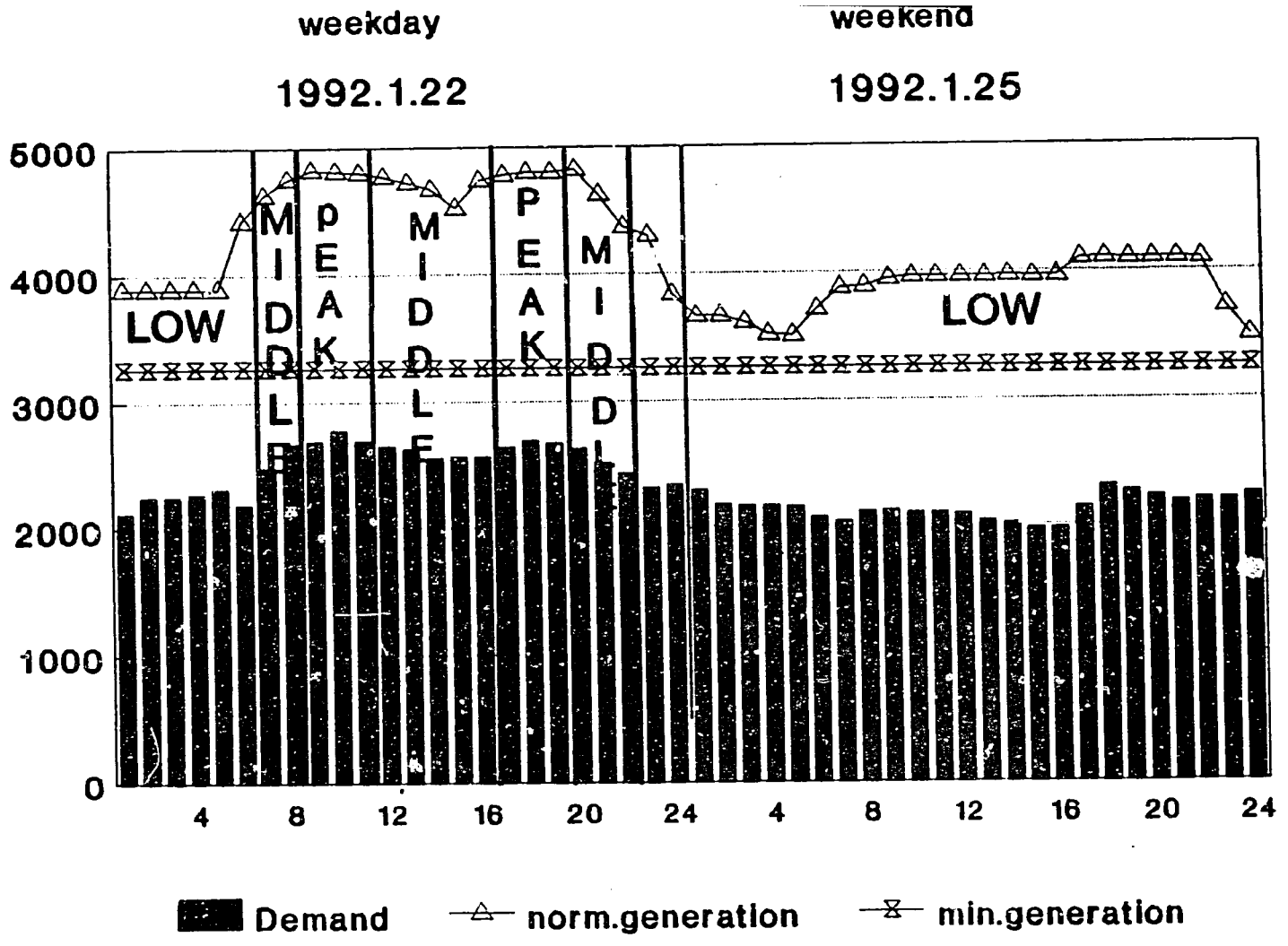

Fig. 8 Differentiation of energy use time

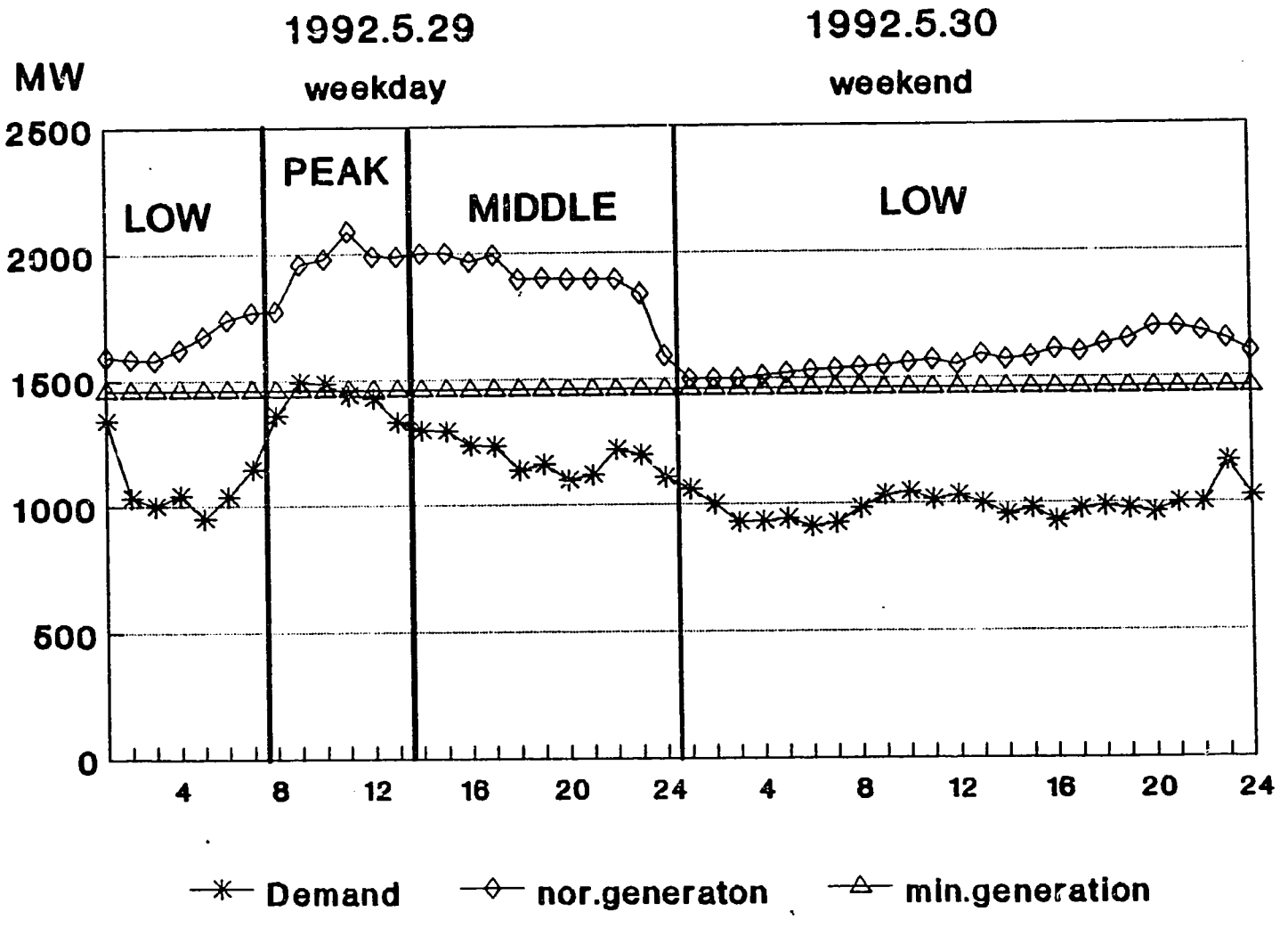

Fig.9 Differentation of time of energy use in summer

weekday energy consumption share is 78% of annual consumption,

weekend energy consumption share is 22% of annual consumption,

peak-tariff energy consumption share is 28% of daily consumption,

middle-tariff energy consumption share is 47% of daily consumption,

low-tariff energy consumption share is 25% of daily consumption,

peak-tariff energy consumption share is 20% of month consumption,

middle-tariff energy consumption share is 35% of month consumption,

low-tariff energy consumption share is 45% of month consumption,

peak-tariff energy generation share is 25% of daily generation,

middle-tariff energy generation share is 42% of daily generation,

low-tariff energy generation share is 33% of daily generation,

peak-tariff energy generation share is 18% of month generation,

middle-tariff energy generation share is 37% of month generation,

low-tariff energy generation share is 45% of month generation,

Acording to this relations energy planning was provided for an every utility .It is shown in table 2.

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Pricing conceptions

ASPECTS	EMBEDED COST	MARGINAL COST
POSITIVE	Cost of components stem directly from allocation of revenue requirements providing total coverage of cost responsibility Costs are assigned on the basis of the reasons they were incurred	Assigns costs in a forward looking manner to send appropriate price signals to consumers Pricing may complement resource development External impacts of electricity use can be incorporated into pricing
NEGATIVE	Historic drivers of system development may no longer be related to current uses May not send correct price signals to consumers	Not tied to utility accounts ideal prices may not generate desired revenue requirements Requires projections of incremental costs

Fig. 10. Analysis of two pricing conceptions

Table 2

UTILITIES	Energy planned for II quarter MWh			
	TOTAL	PEAK	MIDDLE	LOW
Generating utility 'Lithuanian power system'	924	166	342	416
Network utilities:				
Vilnius	437	87	153	197
Kaunas	540	108	189	243
Klaipeda	376	75	131	170
Siauliai	392	78	138	176
Panevezys	312	62	110	140
Alytus	250	50	88	112
Utena	140	28	49	63

5. Valuation of tariff components

When determining the tariff components the main problem is to evaluate production costs. According to economical theory optimal prices must reflect marginal costs. Marginal costs are extra costs to produce an extra output. In a fair competition system these costs are automatically reflected in a price. In our energy system they must be determined artificially.

Increased output of capacity, energy or services (like reliability) in a power system is connected mostly with increased costs (fig. 11). This increment of cost should be forecasted according to the least cost planning principle and technological aspects of the power system (distribution of electricity in network, technical and economical indicators of power plants). This approach is aimed to regulation but not a financial measure.

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Broadly used in electricity pricing is an average cost approach. It relates tariffs and revenues with a financial situation in a power utility. In various approaches it's very important if there are operation costs or perspective costs. In fig. 10 the more detailed characteristics of these approaches are given, positive and negative sides of each are revealed. Hence some mixed approach could be determined.

The main points of the proposed approach could be formulated as follows:

- energy valuations are determined according to variable marginal costs,
- capacity valuations are determined according to constant average cost,
- fixed charge must cover the rest part of the planned revenue.

6. Energy charges reflecting marginal variable cost in the generating utility 'Lithuanian Power System'

According to this approach energy demand vary, i.e. increases or decreases. Energy generation, transmission and distribution system should react to these variations. This reaction causes additional costs. Determination of these costs is a background to establish base and peak energy prices. These costs are characteristic to some power plants only.

For example, if there are several generators, with decreasing demand the most expensive generator will be switched off. And with increasing energy demand the most expensive generator will be switched on. This generator is called a marginal generator. In the Lithuanian power system the marginal generator according to varying conditions could be the Elektrenai thermopower plant or cogeneration power plants working in condense conditions, or the Kaunas hydropower station, or peak energy from abroad. Variable cost in the generating utility is expenses of fuel. So marginal variable cost is defined by marginal fuel consumption in the system. Marginal fuel consumption is evaluated in the appendix

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and shown in the fig.

From the figure we can see the marginal fuel expenditures in all the conditions. It is also shown how energy demand changes with crossing various electricity generation conditions. It determines the time periods with different marginal fuel expenditures (fig. 9, above). These time periods are separated by vertical lines according diferentiation energy used time like in fig. For example, energy price in the first time interval is determined by increments of fuel expenditures in a 300 MW unit regulation conditions. As one could see there are several time intervals with different marginal fuel expenditures. So very short or very similar time intervals could be united.

On this base marginal fuel consumption energy charges could be always calculated by the following formula:

$$m_i^o = b_i k \left(\frac{\eta + 100}{100}\right) \qquad (8)$$

where m_i^o - energy price in the i-th time interval,

k - fuel price,

η - share of own consumption, equals to 4.34 %.

Results of calculation are shown in table 3

Table 3

Interval name	Marginal fuel expens (g/kWh)	Fuel price (rub/t)	Energy price (rub/kWh)
Low	240	4200	1.00
Middle	350	4200	1.47
Peak	430	4200	1.81

7. Hydro pumped storage plant in the marginal evaluation

A hydro pumped storage power plant (HPSPP) at the minimum load operates like consumer. So hydro pumped storage plant at the minimum load should be evaluated by a marginal fuel consumption.

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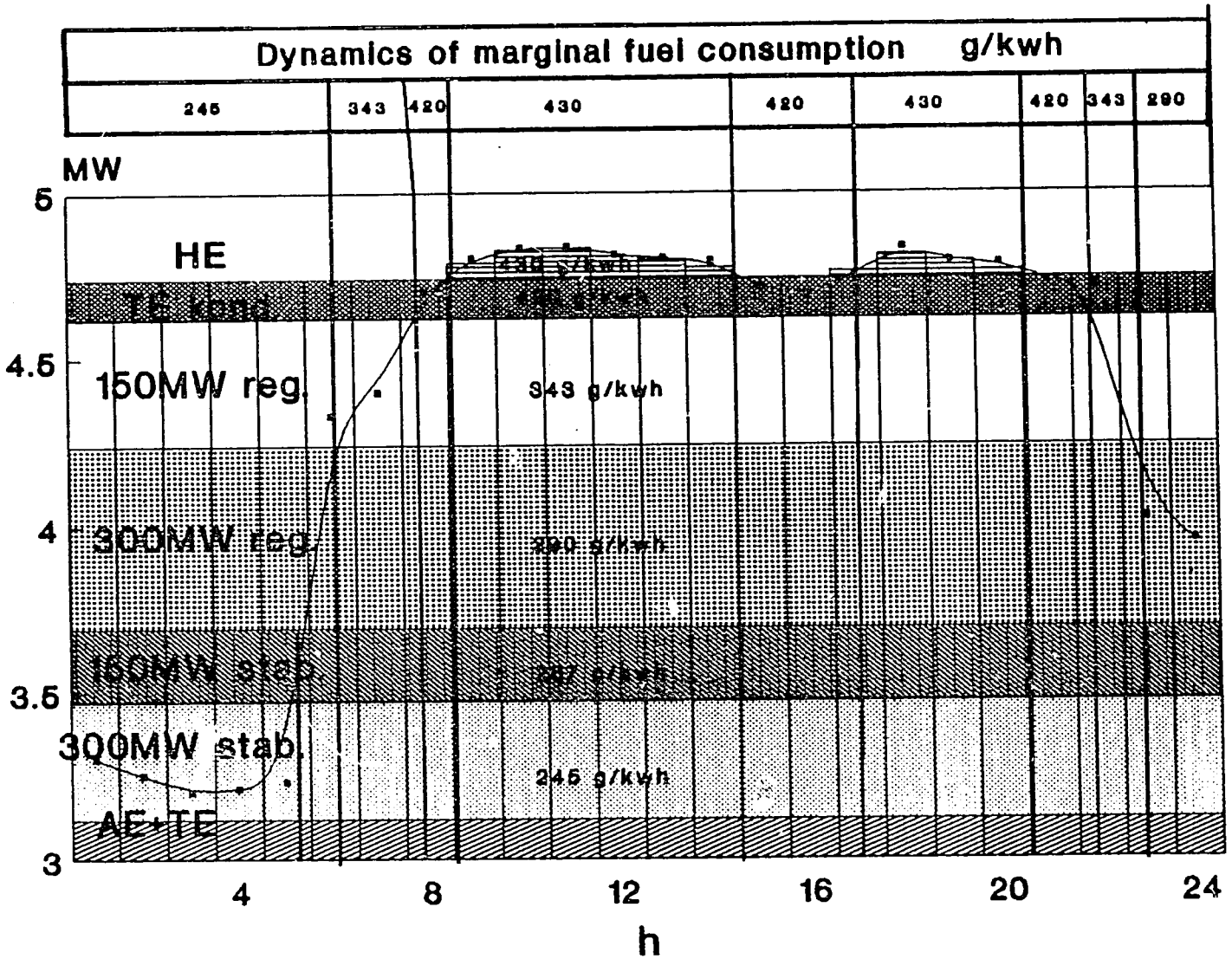

Fig.11 Principle of a marginal fuel consumption (1992.II.8)

We have already found that at the minimum load marginal fuel consumption is about 240 g/kWh. During the peak time HPSPP will generate electricity with 70% efficiency. So electricity from a HPSPP could be evaluated as a marginal fuel consumption in the following way:

$$b_{hps} = b_{night} /0.7 = 240 / 0.7 = 343 \text{ g/kwh}$$

So we can see that a HPSPP in the merit order will be included before including cogeneration plants in condense operation. Peak energy evaluated according to condensing operation of cogeneration plants (430g/kwh) create incentives for a profitable HPSPP operation in the Lithuanian power system.

8. The Baltic power market and a marginal conception

At present application of this approach is complicated as Lithuanian power plants are operating on a minimal, even load and doesn't react to variations of demand. As one could see from fig. 9 variation of demand causes export variations only. Hence export prices should reflect marginal cost and valuations should be determined as follows:

$$m_l = P^{l}_{ex}$$

$$m_m = P^{m}_{ex}$$

$$m_p = P^{m}_{ex}$$

Export prices will depend on interstate contracts in the newly created Baltic power market (fig. 14), where base energy sellers are Estonia and Lithuania and peak energy seller is Latvia. All kinds energy will purchase Belarus and Kaliningrad. They could chose where from to buy night, day and peak energy. Peak energy prices should be determined by the Latvian power system proposed prices. Base energy price should be determined by the Estonia power system proposed price, and if their deliveries

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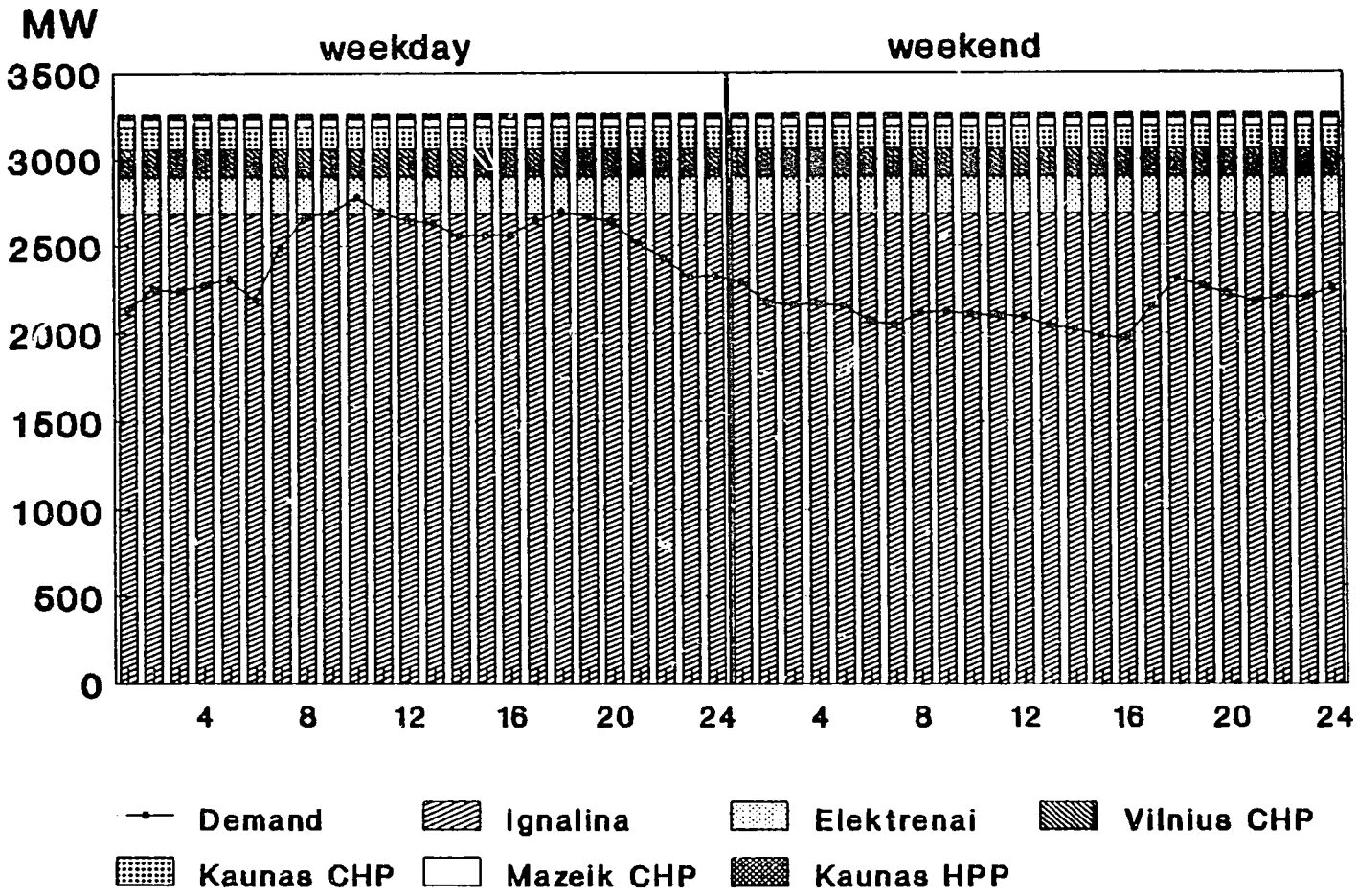

Fig.12 Load curve January 25, 1992

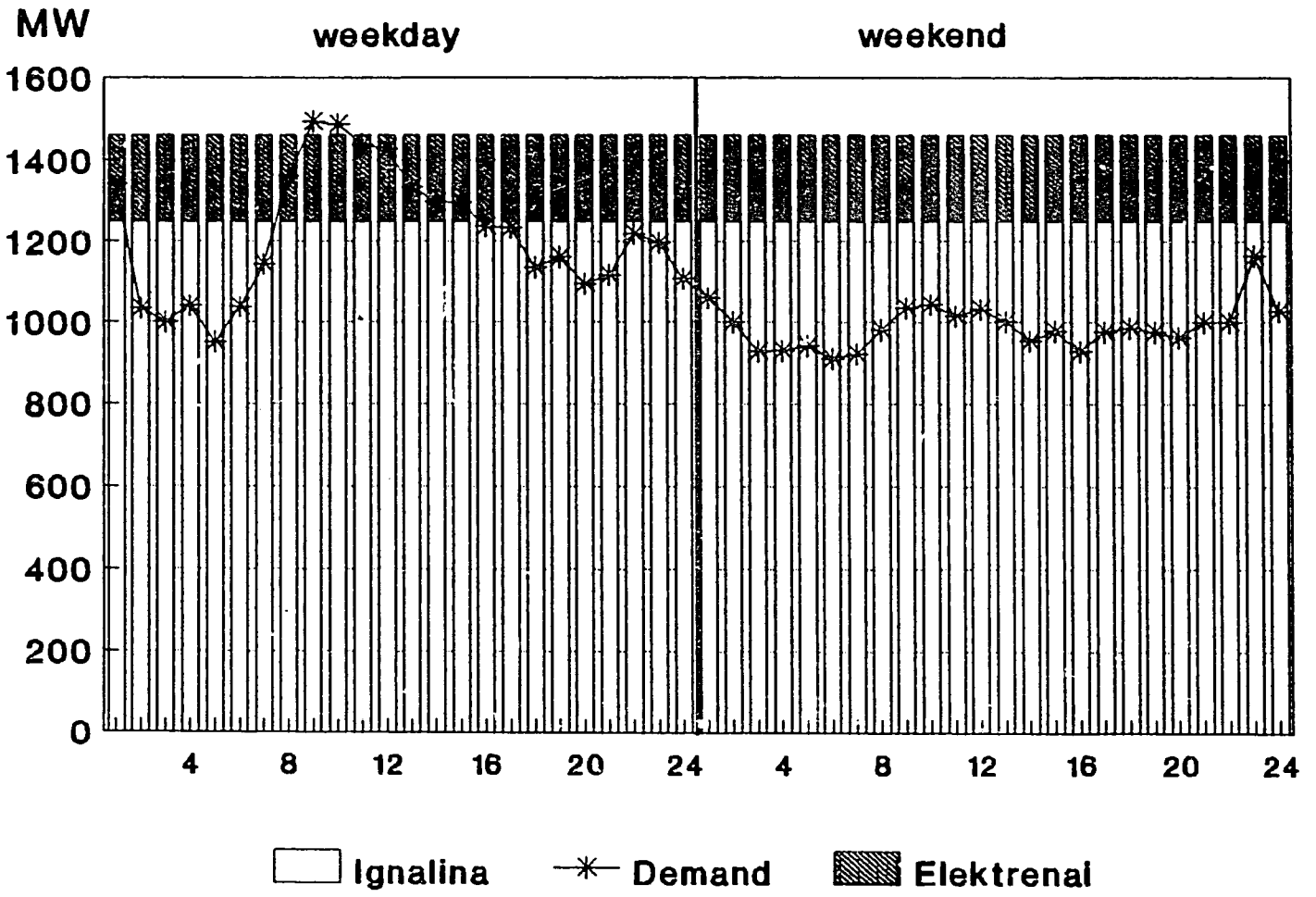

Fig.13 Load curves of May 29 and 30, 1992

will not be sufficient the base energy prices could be dictated by the Lithuanian power system.

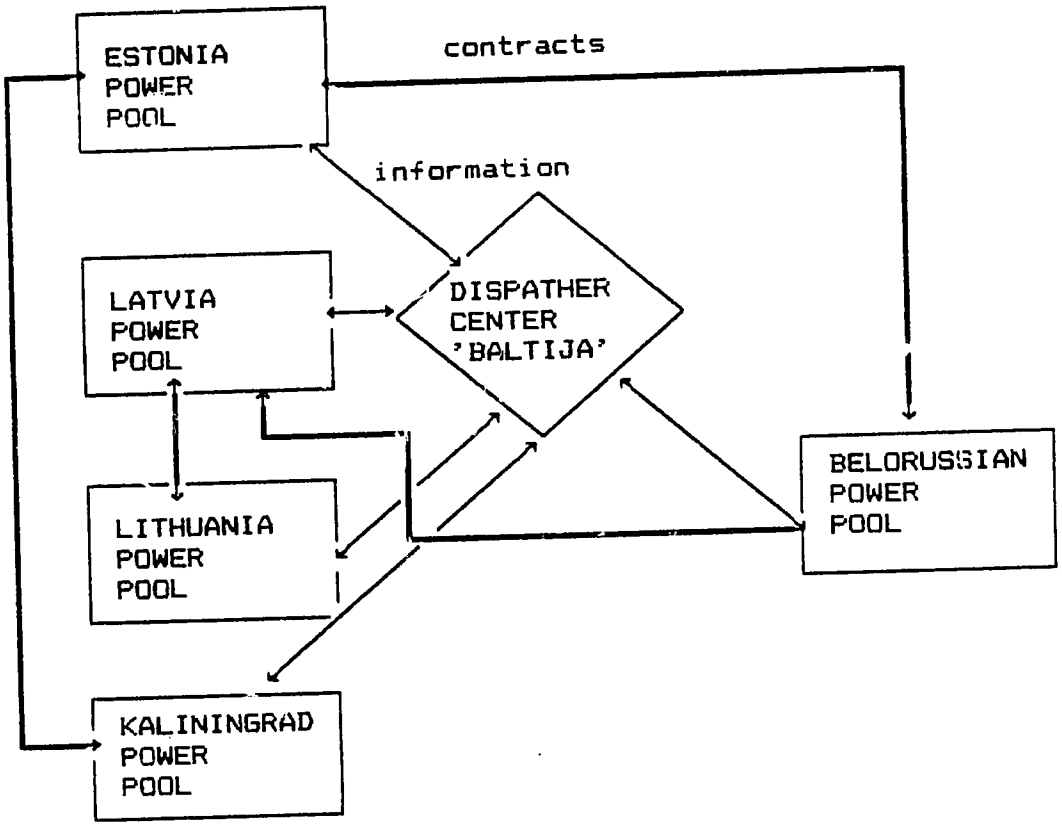

Fig. 3. The Baltic power market

9. Charge of the required capacity during the peak in the generating utility

During the peak time price of required capacity acording to marginal cost principles theoretically must reflect a perspective development cost and, hence, to optimize development of the system. But from utility point of view tariff should be not only optimizing measure, but finansing too. So in total tariff should reflect all the embeded cost to colect necessary revenue. Revenue can be defined in such a way:

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REVENUE = EXPENSES + CAPITAL * RETURN.

Expenses consist of constant and variables costs in generating utility and shown in the table 4

Table 4

Expenses in the generating utility "LPS" in the second quarter of 1992

Items	mln.rb.	%
constant cost	124	10
variable cost	1154	90
expenses	2178	100

Return on capital is very important for an economical regulation in generating utility in the case of private capital. In a private electricity system through this measure investments can be regulated. In the case of state capital which can not participate in the capital market this measure play only an accounting role. Return on capital in the existing situation covers interest, profit and taxes. We agree that return on capital in our case should cover interest on a state capital . But some allowance for profit and taxes should depend on amount of sold energy. This problem requires an additional discussion. But in this report we asume that all items are covered by return on capital like in the existing situation (tab 5).

So a revenue can be evaluated in a following way:

REVENUE = 1278 + 968 * 0.037 = 1314.mln.rb.

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Table 5

An existing projection on return of capital, second quarter of 1992

Items	mln.rb.	%
state capital	988	100
return on capital	37	3.7
taxes	11	1.1
interests	17	1.7
profit left in the utility	9	0.9

One part of revenue consists from energy sold and the other - from charged capacity. So capacity price can be defined in the following way:

$$m_c = \frac{\text{REVENUE} - \text{INCOME FROM ENERGY}}{\text{REQUIRED CAPACITY}} \qquad (9)$$

INCOME FROM ENERGY = $m_p * E_p + m_m * E_m + m_i * E_i =$

$= 1.81 * 166 + 1.47 * 342 + 1.81 * 416 = 1219$ mln.rb.

REQUIRED CAPACITY =1000000 kW

$$m_c = \frac{(1314 - 1219) * 10^6}{1000000} = 97 \text{ rb./kW}$$

9a About a fixed charge in the generating utility

Fixed charge should reflect a cost due to allocations of consumers. Generating utility "LPS" doesn't supply energy to consumers directly. So any cost depending on consumers type or allocation doesn't occur. Therefore a fixed charge is assumed to be zero.

$m_f = 0$

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10. *Energy charges reflecting marginal variable cost in electricity network utilities*

Above evaluated energy components reflect production costs only, so according to it electricity could be sold only to network distribution utilities. They will formulate a consumers tariff covering network operation costs also. A total network utilities cost consists from a constant cost and a variable cost. The variable cost is connected with an electricity transmission. Transmission cost is shown in table and fig 5.

If one wants to evaluate a variable network cost, in the marginal terms, he must know their dependance on a demand curve. It can be defined by marginal losses in the electricity network. Marginal losses (Π_i) at low, middle and peak demand are evaluated in the appendix. Then energy distribution marginal cost in each time period could be calculated according to:

$$m_i^t = \Pi_i \, m_i^p \qquad (10)$$

where m_i^t - marginal energy transmission cost in an i-th time interval

m_i^p - energy price paid to producer by a network utility in an i-th time period.

A network utility will sell energy to consumer by a price determined from

$$m_i = m_i^t + m_i^p = m_i^p \, (1 + \Pi_i) \qquad (11)$$

where m_i - energy charge for consumer in the i-th time period.

Calculation of concrete energy charges in all the electricity distribution network utilities is shown in table 6.

In this table energy prices are calculated according to formula (15), using earlier calculated producer energy charges, i.e. m_l^g = 1.00 rub/kWh, m_m^g = 1.47 rub/kWh, m_p^g = 1.81rub/kWh.

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Table 5

Utilities	Π_l	Π_m	Π_p	C_l rub/kWh	C_m rub/kWh	C_p rub/kWh
Kaunas ENU	0.125	0.167	0.175	1.12	1.72	2.12
Vilnius ENU	0.137	0.202	0.236	1.13	1.77	2.24
Šiauliai ENU	0.136	0.156	0.165	1.13	1.70	2.11
Panevežys ENU	0.140	0.168	0.175	1.14	1.72	2.13
Klaipeda ENU	0.143	0.205	0.225	1.14	1.77	2.22
Alytus ENU	0.152	0.203	0.253	1.15	1.77	2.27
Utena ENU	0.198	0.269	0.297	1.19	1.87	2.35

Energy valuations are very similar at different utilities so it seems that the same price could be used. But we'll use the different prices and only at the end we'll make conclusions.

11. Charge of a required capacity at the peak time

The main tariffs principle is that consumers should cover all the costs caused by energy generation, transmission and distribution. In this report we couldn't say exactly what share of constant costs in networks is connected with a maximal energy demand and what with consumers type. We think that 70% of total constant network cost are connected with a consumer and only 30% with the required capacity. It is easily explained as installed capacity of lines and transformators in most cases is significantly higher than a required maximal capacity, particulary in the present time, when demand is decreasing. According to the marginal cost principle extra increase of demand during load maximum time could cause no extra costs. So it is no sense to send strong signals to consumers about expenses for increasing networks capacity. 30% of constant cost would be enough to include in a capacity charge. Calculations of capacity charge can be provided in two ways: diferent for eatch utility or the same for all utilities acording to folowing formulas:

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$$m_c^{t\,i} = \frac{0.3 * \text{constant cost}}{P_i}.$$

or

$$m_c^t = \frac{0.3\ \Sigma_i\,(\text{constant cost})_i}{\Sigma_i P_i}$$

where P_i – required capacity at the peak time in the i- utility.

Data and results of this calculation are given in the table 7.

Table 7

Utilities	constant cost t.rb.	capacity req. at peak time(P) MW	m_c rb/kW
Vilnius	29604	300	29
Kaunas	31067	360	26
Klaipeda	32300	250	38
Siauliai	30215	260	34
Panevezys	22906	180	38
Alytus	21646	120	54
Utena	20700	70	70
Total	188438	1540	36

From table 7 could be made a conclusion: the smaller capacity the higher charge. It is a wrong incentive from an optimizing network point of view. In utilities with tendency of growing capacity this process will be stimulated by a decreasing charge.

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In utilities with tendency of decreasing demand and not fully using installed capacity. This process will be stimulated by increasing charge. Therefore we'll use an average charge m_c=36 rub./kW per quarter.

12. Fixed charge and demand side management

Pricing system should provide good incentives from the demand side management point of view. Profit seeking and energy selling processes must be decoupled. In this case two problems arise:

- rate of return planning,
- profit collection from consumers.

In planning rate of return it is necessary to check in what field of activity the utility has made an investment. If it was made in energy saving field the norm of return must be higher.

A utility will not insist to sell energy as much as possible if profit they could collect will depend on tariff components not connected with an amount of energy sold. Such a component is a fixed charge.

13. A fixed charge in network utilities

A fixed charge should fulfill a revenue requirement, because energy and capacity charges were established without relating with a required revenue. A required revenue for network utility can be evaluated like in a case of generating utility

$$REVENUE^n = EXPENSES^n + CAPITAL^n * RETURN^n$$

Expenses consist of constant and variables cost in network. A variable cost is equal to expenses for electricity purchase for generating utility 'LPS' according to evaluated charges. It is shown in the table 8.

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Table 8

Purchase of electricity from the generating utility 'LPS'

UTILITIES	capacity MW	energy for II quarter mln.kWh			expenses for buyng electricity mln.rb.
		PEAK	MIDDLE	LOW	
Vilnius	300	87	153	197	615
Kaunas	360	108	189	243	758
Klaipeda	250	75	131	170	530
Siauliai	260	78	138	176	551
Panevezys	180	62	110	140	434
Alytus	120	50	88	112	346
Utena	70	28	49	63	196

Table 9

Expenses in the network utilities mln.rb.

Items	Viln.	Kaun.	Klp.	Siaul	Panev	Alyt	Uten	Total
constant cost	29	31	32	30	23	21	20	188
variable cost	615	758	530	551	434	346	196	3430
expenses	644	789	562	581	457	367	216	3618

Return on capital like in a case of generating utility 'LPS' : the main in accounting financial balance in the network utilities. A detail project of return on capital is given in the table 10

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Table 10

An existing projection of return on capital in network utilities second quarter of 1992

	STATE CAPITAL		RETURN ON CAPITAL							
			interest		taxes		profit		total	
	mln.rb	%	mln.rb	%	mln.r	%	mln.rb	%	mln.b	%
Vilnius	224	100	3.93	1.75	2.44	1.1	2.05	.9	8.	3.7
Kaunas	268	100	4.69	1.75	2.91	1.1	2.45	.9	10.	3.7
Klaipeda	276	100	4.83	1.75	3.00	1.1	2.52	.9	10.	3.7
Siauliai	217	100	3.80	1.75	2.36	1.1	1.98	.9	8.	3.7
Panevezy	195	100	3.42	1.75	2.13	1.1	1.78	.9	7.	3.7
Alytus	168	100	2.94	1.75	1.83	1.1	1.54	.9	6.	3.7
Utena	183	100	3.21	1.75	2.00	1.1	1.67	.9	6,	3.7
Total	1532	100	26.82	1.75	16.67	1.1	13.98	.9	57.7	3.7

We think that this projection should be changed removing taxes. Taxes should be related with energy but not with capital. So this question requires an additional discussion. But in this report the existing project of return on capital will be used.

So revenue for each utility is evaluated in table 11

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Table 11

Plan of revenue for the second quarter of 1992

	expenses	return on capital	revenue
	mln.rb	mln.rb	mln.rb
Vilnius	644	8.4	652.4
Kaunas	784	10.0	794
Klaipeda	562	10.4	572.4
Siauliai	581	8.1	588.1
Panevezy	457	7.3	464.3
Alytus	367	6.3	373.3
Utena	216	6,8	222.8
Total	1532	57.47	3667.3

One part of revenue consists of an energy sold and the other - from a capacity charge. The rest part of revenue should consist of fixed charge. This part can be defined for each network utility according to following formulas:

$$RR_i = REVENUE_i - INCOME\ FROM\ ENERGY_i - INCOME\ FROM\ CAPASITY_i$$

Results of calculations are given in table 12

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Table 12

The rest part of revenue in the second quarter of 1992

Utili-ties	income from energy	income from capacity	revenue	the rest revenue
	mln.rb.	mln.rb	mln.rb.	mln.rb.
Vilnius	46	579	652.4	26
Kaunas	56	715	794	23
Klaipeda	39	497	572.4	36
Siauliai	40	519	588.1	29
Panevezy	28	413	464.3	23
Alytus	18	331	373.3	24
Utena	11	185	222.8	26
Totall	238	3239	3667.3	187

The rest part of revenue in each utility should be divided through fixed charge between varius consumers. We assume that the part of revenue could be covered by forht categories of consumers;

the retail rural consumer,
urban consumer,
industrial low tension consumers,
industrial high tension consumers.

The fixed charge could help to collect a revenue needed but it could be distributed between consumers according to their categories and their influence to the constant utility operation cost. Structure of consumers is gven in the table 5

Every rural consumer needs a higher service cost from the utility. Industrial consumers possess more complicated connections and it causes additional costs, especially for a high tension connection. Hence we propose the next relation to determine the fixed cost:

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$$m_F^R = 2\ m_F^R\ ,$$

$$m_F^{Li} = 20\ m_F^u\ ,$$

$$m_F^{hi} = 20\ m_F^u\ ,$$

where m_F^R, m_F^{Li}, m_F^{hi} - fixed charges for rural, urban, low tension and high tension industrial consumers.

Then the following balance equation could be proposed:

$$\Sigma m_F^i * N_i = RR$$

where N_i - number of urban, rural, industrialwith low and high tension consumers.

From the balance equation one could calculate m_F^u :

$$m_F^u = RR/(N_u + 2\ N_R + 20\ N_{Li} + 200\ N_{hi}\ .$$

Table 13

	Viln	Kaun	Klaip	Siaul	Panev	Al	Ut	Total
Constant cost mln.rub.	29	31	32	30	23	21	20	186
Rest of rev mln.rub.	26	23	36	29	23	24	20	181
Number of rural cons.	82000	69000	64000	60000	59000	59000	58000	451000
Number of urban cons.	209000	166000	123000	101000	73000	63000	42000	777000
Number of low ten. ind.cons.	194	183	162	135	92	85	104	955
Number of high ten. ind. cons.	254	236	148	120	104	95	71	1026
Total, th.	291448	235419	187310	161255	132196	122180	100175	1.23 mln.

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We must add that these equations are only examples and some appropriate method should be defined for a practical use.

Results of calculation are given in the next table

Table 14

Fixed charge rb./q

consumers	Vil	Kaunas	Klaip	Siaul	Panev	Alyt	Utena
Urban	60	64	126	117	107	118	114
Rural	120	128	252	234	214	236	228
Low tens. ind.	1200	1280	2520	2340	2140	2360	2280
High tens. industrial	12000	12800	25200	23400	21400	23600	22800

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Final tariff system

Table 15

utilities	Tariff komponents							
	fixed charge rb.q. kategories				capas ityo rub/kw.	low rub/kwh	midlle rub/kwh	peak rub/kwh
	I	II	III	IV				
GENERATING								
'LES'	-	-	-	-	97	1	1.47	1.81
NETWORKS								
Vilnius	60	120	1200	12000	126	1.12	1.72	2.12
Kaunas	64	128	1280	12800	123	1.13	1.77	2.24
Klaipeda	126	252	2520	25200	135	1.13	1.70	2.11
Siauliai	117	234	2340	23400	131	1.14	1.72	2.13
Panevezys	107	214	2140	21400	135	1.14	1.77	2.22
Alytus	118	236	2360	23600	151	1.15	1.77	2.27
Utena	114	328	3280	32800	167	1.19	1.87	2.35

14. Simplification

When network utilities doesn't use an additional charge for a capacity during peak time all the revenue should be covered by a fixed charge. Exspenses do to losses could be included into the fixed charge too. So planned revenue, in such cace could be calculated according to

Revenue = constant cost + losses + return on capital

and fixed charge calculated by the same formula as above. Resullts of calculations reprezented in the table 16

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Simplified final tariff system

Table 16

Utilities	Tariff components							
	fixed charge rb.q. categories				capa-city rub/kw.	low rub/kwh	middle rub/kwh	peak rub/kwh
	I	II	III	IV				
GENERATING								
'LES'	–	–	–	–	97	1	1.47	1.81
NETWORKS								
Vilnius	131	262	2620	26200	97	1	1.47	1.81
Kaunas	200	400	4000	40000	97	1	1.47	1.81
Klaipeda	155	310	3100	31000	97	1	1.47	1.81
Siauliai	260	520	5200	52000	97	1	1.47	1.81
Panevezys	234	468	4680	46800	97	1	1.47	1.81
Alytus	169	340	3400	34000	97	1	1.47	1.81
Utena	172	344	3440	34400	97	1	1.47	1.81

15. SOME SCENARIOS

There are two directions in organization structure of electricity industry in the world: integrated and disintegrated. As an example of a good integrated power system is the U.S.A. power sysstem where big companies own generation, transmission and distribution systems. On the other hand there are efficient disintegrated power systems in Europe. Disintegration and unbundling of power systems are proposed by European Community in order to create competitive electricity industries. This requirement is reflected in the 23 article of the EEC document "Proposal for a Counsil Directive concerning common rules for the internal market in electricity" (see Annex 4).

The Lithuanian Power System with a surplus of installed

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capacity should be prepared to enter the common European market. So the decentralisation principle must be included in restructuring of the institutional order. In the table 17 the unbundled accounting is provided for network utilities.

From this table we can see that prices in different utilities without subsidies are different. But these differencies are decreasing. As we can see from the table 17 at the end of 1991 differencies between prices in the Siauliai Network Utility and the Utena Network Utility were 40% and at the end of 1992 it will be only about 20%.

Table 17

A new approach in calculating average prices in 1991 and 1992

		Network utilities					
		Kaunas		Siauliai		Utena	
		1992	1991	1992	1991	1992	1991
Purchased en.	GWh	180	276	107	252	41	74
Wholesale pr.	rb/kWh	1.4	0.31	1.4	0.31	1.4	0.31
Purch. expense	M rb	252	8.6	150	7.8	52	2.3
Fixed cost	-"-	25	3.3	22	2.5	16	2.0
Total cost	-"-	277	11.9	172	10.3	69	4.3
Capital	-"-	1265	273	1054	217	873	185
Rate of return		0.0125		0.0125		0.0125	
Return on cap.	M rb	15.8	3.41	13.0	2.71	1.0	2.31
Revenue	Th rb	293	15.3	185	13.0	80	6.7
Energy sold	GWh	173	250	106	217	38	62
Average price	Rb/kWh	1.69	0.061	1.74	0.06	2.1	0.1

The main reason of it was an increasing share of fuel cost in the price and fuel cost was almost the same in each utility. So there were no real needs to have the same price in every utility and no no need for cross-subsidies in accounting system.

After reshaping the accounting system the other important

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thing in the pricing system is costing. In a power system only fuel cost is evaluated by market, when the other things still should be defined artificially. In the table 18 there are given three scenarios for costing in the pricing system.

Table 18

Scenarios	Assets tal/kW	Depreciation tal/kW/y	Labor cost tal/kW/y	Fuel cost tal/y	Ret. on cap. tal	Revenue tal	Tariff		
							av. char	cap. char	en. char
I	2100	37	74	30000	315	30426	6.1	426	6
		0.12%	0.24%	98.6%	1%	100%			
II	2100	8666	74	30000	315	39055	7.8	9055	6
		22.2%	0.19%	76.8%	0.8%	100%			
III	130000	2321	74	30000	195000	51895	10.4	21895	6
		4.5%	0.14%	58%	37%	100%			

Where:

I scenario reflects the present situation in the existing accounting, i.e. only fuel price is on world level,

II scenario includes international fuel price and depreciation is evaluated by replacement cost at world prices,

III scenario includes international level of fuel prices as also of capital and of return on capital.

CONCLUSIONS

1. In favour of simplification some calculations could be removed.

2. Calculations showed that energy charge depending on networks utility differs insignificantly, so price could be the same, i.e. networks are purchasing and selling at the same price.

3. When determining the tariffs the principle of unbundled accounting should be valid. So calculations based on average costs

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should be removed. A charge for capacity in electricity distribution utilities could be equaled to that proposed by the generating utility. I.e. utility is buying and selling capacity at the same price.

4. The fixed charge in utilities is very useful to oblige utilities to worry about energy saving at the demand side. Fixed charge is also very important in an unbundled accounting.

5. Some allowance for profit should be provided in the fixed charge after approval in the tariff regulatory commission.

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A P P E N D I X - A -

I. Determination of marginal fuel expenditures in the power system

We should determine the marginal fuel expenditures and their dependance from a demand curve. Let's start our calculation with data from 1990, then all the existing capacities were fully employed (fig. 15).

Let's study a winter weeekday energy demand curve and a corresponding generation process from a marginal fuel expenditures point of view. Marginal expenditures mean an increment of fuel consumption when energy demand increases by a unit. As one could see from fig. 11 energy demand varies during a day, and it causes the different energy generation conditions (shown in figure by different stripes). These conditions are arranged in increasing order. Conditions crossed by a demand curve are called marginal conditions. In general, the marginal fuel cost is calculated according to formula:

$$b_i = b_r + \Delta b \qquad (12)$$

where b_i - marginal fuel expenditures during i-th time period,

b_r - increments of fuel expenditures in marginal conditions,

Δb - changes of fuel expenditures in the system caused by increased energy generation in j-th conditions.

Marginal fuel expenditures calculated according to this formula depend on marginal conditions. All the conditions shown in fig. 8 according to load level could become marginal except of 1 and 2.

Marginal fuel expenditures in the power system

<u>Marginal conditions No.</u> 3

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$$b_r = \frac{B_t + b_e \times P_{min}}{P_{min}} \qquad (13)$$

where B_t - idle fuel expenditures, equal to 8,46 t,

b_e - increments of comparative fuel expenditures in conditions of technical minimum, equal to 0,273 t/MWh,

P_{min} - a technical minimum for a 300 MW units, equals to 120 MW.

Putting into formula (8) these values we get

$$b_r = \frac{8,46 + 0,273 \times 120}{120} = 0,343 \text{ t/MWh} = 343 \text{ g/kWh}$$

$$\Delta b = \frac{B_{pal}}{P_{min} t} \qquad (14)$$

where t - time of units standstill, could equals to 6 h,

B_{pal} - fuel expenditures to start operation of 300 MW unit after 6 h standstill, equals to 70 tonnes,

$$\Delta b = - \frac{70}{120 \times 6} = - 0,0972 \text{ t/MWh}$$

minus sign means that these expenditures could be avoided if consumer will use energy. Hence marginal fuel expenditures in these conditions will be

$$b = b_r + \Delta b = 0.343 - 0.0972 = 0.245 \text{ t/MWh}$$

Marginal conditions No. 4

There - B_t = 5.025 t,

b_e = 0.288 t/MWh,

P_{min} = 60 MW,

$$b_r = \frac{5.025 + 0.288 \times 60}{60} = 0.371 \text{ t/MWh},$$

t = 6 h (assumed),

B_{pal} = 30 t,

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$$\Delta b = \frac{30}{60 \times 6} = 0.0833 \text{ t/MWh},$$

$$b = b_r + \Delta b = 0,371 - 0.0833 = 0.287 \text{ t/MWh},$$

Marginal conditions No. 5

$$b_r = \frac{b'(P_i - P_{min}) + b''(P_n - P_i)}{P_n - P_{min}} \qquad (15)$$

(average of comparative fuel expenditures increments)

where b' - comparative fuel expenditures increments for a 300 MW unit in efficient load interval, equals to 0.273 t/MWh,

b'' - comparative increments of fuel expenditures for a 300 MW unit in inefficient load interval, equals to 0.313 t/MWh,

P_i - efficient load of the unit, equals to 222 MW

$$b_r = \frac{0.273\ (222 - 120) + 0.313\ (300 - 222)}{300 - 120} = 0.290 \text{ t/MWh},$$

$\Delta b = 0$ (has no influence to the other conditions),

$$b = b_r + \Delta b = 0,290 + 0 = 0.290 \text{ t/MWh}$$

Marginal conditions No.6

$$b_r = \frac{b'\ (P_i - P_{min}) + b''\ (P_n - P_i)}{P_n - P_{min}} \qquad (16)$$

(average of comparative increments of fuel expenditures)

where b' - comparative increments of fuel expenditures for a 150 MW unit in an efficient load interval, equals to 0.986 t/MWh,

b'' - comparative increments of fuel expenditures for a 150 MW unit in inefficient load interval, equals to 0.388 t/MWh,

P_i - an efficient load of the unit, equals to 100 MW,

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$$b_r = \frac{0.288\ (100 - 60) + 0.388\ (150 - 100)}{150 - 60} = 0.343\ t/MWh$$

$\Delta b = 0$ (no influence).

Marginal conditions No. 7

Here $b_r = 430$ g/kWh (increments of fuel expenditures in cogeneration plants operating in condense conditions.

$\Delta b = 0$ (has no influence to the other conditions),

$$b = b_r + \Delta b = 430 + 0 = 430\ g/kWh = 0.430\ t/MWh$$

Marginal conditions No. 8

Here $b_r = 0$ (HPS doesn't use fuel),

$\Delta b = 430$ g/kWh = 0,430 t/MWh (we assume the most inefficient thermal conditions),

$$b = b_r + \Delta b = 430 + 0 = 430\ g/kWh = 0.430\ t/MWh$$

II. Determination of energy components of tariff according to marginal costs in network utilities

According to the marginal cost approach the variable cost is connected with marginal energy losses. in the network. These losses consist from load losses at every time moment. In general, they could be calculated by a formula:

$$\Delta P = R\ I^2 = R\ (\frac{P}{U})^2 = \frac{R}{U^2}\ P^2 \qquad (17)$$

where ΔP - load losses,

R - active network resistance of transmission,

I - required consumers load current,

P - required consumers demand,

U - tension in network.

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In this formula resistance R and tension U are easily determined for a one electricity transmission line and for one transormator. For a more complicated network with tigh lines of various length with various tensions a general network indicator is determined. Then formula (16) could be rewritten:

$$\Delta P = r\ P^2 \qquad (18)$$

where r - a general network indicator.

Marginal load losses means increasing of load losses in network when demand load is increased by a unit. Mathematically it could written as a derivative of (18)

$$\Pi = \frac{\delta\ \Delta P}{\delta P} = \frac{\delta\ (r\ P^2)}{\delta P} = 2\ rP \qquad (19)$$

For an evaluation of real load losses one needs to determine a general network indicator. Though this indicator reflects an engineering side of the network, its calculation is very complicated. Hence it could be calculated from the data according to the formula:

$$\Delta P_N\ t_N + \Delta P_D\ t_D + \Delta P_P\ t_P = A, \qquad (20)$$

where ΔP_N ΔP_D, ΔP_P - load losses in network during night, during day and during peak time,

t_N, t_D, t_P - duration of day, night and peak time intervals,

A - energy losses during a day.

Putting (18) into (20), we get

$$r\ (P_N^2\ t_N + P_D^2\ t_D + P_P^2\ t_P) = A, \qquad (21)$$

from (21) we could determine a general network indicator r

$$r = \frac{A}{P_N^2\ t_N + P_D^2\ t_D + P_P^2\ t_P} \qquad (22)$$

According to these formulas one could roughly calculate concrete increments of losses in different network utilities.

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Kaunas electricity network utility

$$A = \frac{E\ L}{100},$$

where E - energy daily demand in the Kaunas electricity network utility (according to fig. equals to 13672 MWh),

L - share of losses in Kaunas ENU (equals to 7.72 % data of 1989)

$$A = \frac{13672 \times 7.72}{100} = 1055 \text{ MWh},$$

P_l - average capacity at night, equals to 450 MW,

P_m - average capacity at day, equals to 600 MW,

P_p - average capacity during peak time, equals to 630 MW,

$$r = \frac{1055}{450^2 \times 8 + 600^2 \times 11 + 630^2 \times 5} = 0.0001394$$

$$\Pi_l = 2 \times rP_N = 2 \times 0.0001394 \times 450 = 0.125$$

$$\Pi_m = 2 \times rP_D = 2 \times 0.0001394 \times 600 = 0.167$$

$$\Pi_p = 2 \times rP_p = 2 \times 0.0001394 \times 630 = 0.175$$

Vilnius electricity network utility

$$A = \frac{8434 \times 9.52}{100} = 803 \text{ MWh}$$

$$r = \frac{803}{250^2 \times 8 + 370^2 \times 11 + 430^2 \times 5} = 0.000274$$

$$\Pi_l = 2 \times rP_N = 2 \times 0.000274 \times 250 = 0.137$$

$$\Pi_m = 2 \times rP_D = 2 \times 0.000274 \times 370 = 0.202$$

$$\Pi_p = 2 \times RP_p = 2 \times 0.000274 \times 430 = 0.236$$

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Šiauliai electricity network utility

$$A = \frac{7699 \times 7.1}{100} = 546 \text{ MWh}$$

$$r = \frac{546}{280^2 \times 8 + 320^2 \times 11 + 340^2 \times 5} = 0.000244$$

$$\Pi_l = 2 \times rP_N = 2 \times 0.000244 \times 280 = 0.136$$

$$\Pi_m = 2 \times rP_D = 2 \times 0.000244 \times 320 = 0.156$$

$$\Pi_p = 2 \times rP_P = 2 \times 0.000244 \times 340 = 0.165$$

Panevežys electricity network utility

$$A = \frac{5638 \times 7.9}{100} = 444 \text{ MWh}$$

$$r = \frac{444}{200^2 \times 8 + 240^2 \times 1 + 250^2 \times 5} = 0.000350$$

$$\Pi_l = 2 \times rP_N = 2 \times 0.000350 \times 200 = 0.140$$

$$\Pi_m = 2 \times rP_D = 2 \times 0.000350 \times 250 = 0.168$$

$$\Pi_p = 2 \times rP_p = 2 \times 0.000350 \times 250 = 0.175$$

Klaipeda electricity network utility

$$A = \frac{4472 \times 9.61}{100} = 430 \text{ MWh}$$

$$r = \frac{430}{140^2 \times 8 + 200^2 \times 11 + 220^2 \times 5} = 0.000512$$

$$\Pi_l = 2 \times rP_N = 2 \times 0.000512 \times 140 = 0.143$$

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$$\Pi_m = 2 \times rP_D = 2 \times 0.000512 \times 200 = 0.205$$

$$\Pi_p = 2 \times rP_p = 2 \times 0.000512 \times 220 = 0.225$$

Alytus electricity network utility

$$A = \frac{3131 \times 9.11}{100} = 285 \text{ MWh}$$

$$r = \frac{285}{90^2 \times 8 + 120^2 \times 11 + 150^2 \times 5} = 0.000848$$

$$\Pi_l = 2 \times rP_N = 2 \times 0.000848 \times 90 = 0.152$$

$$\Pi_m = 2 \times rP_D = 2 \times 0.000848 \times 120 = 0.203$$

$$\Pi_p = 2 \times rP_p = 2 \times 0.000848 \times 150 = 0.253$$

Utena electricity network utility

$$A = \frac{1981 \times 11.68}{100} = 231 \text{ MWh}$$

$$r = \frac{231}{60^2 \times 8 + 80^2 \times 11 + 90^2 \times 5} = 0.0001653$$

$$\Pi_l = 2 \times rP_N = 2 \times 0.0001653 \times 60 = 0.198$$

$$\Pi_m = 2 \times rP_D = 2 \times 0.0001653 \times 80 = 0.264$$

$$\Pi_p = 2 \times rP_p = 2 \times 0.0001653 \times 90 = 0.297$$

III. COMPUTER MODELLING OF MARGINAL COSTS IN THE LPS

There is a mathematical model created to calculate marginal costs in LPS. The task is solved using a standard linear

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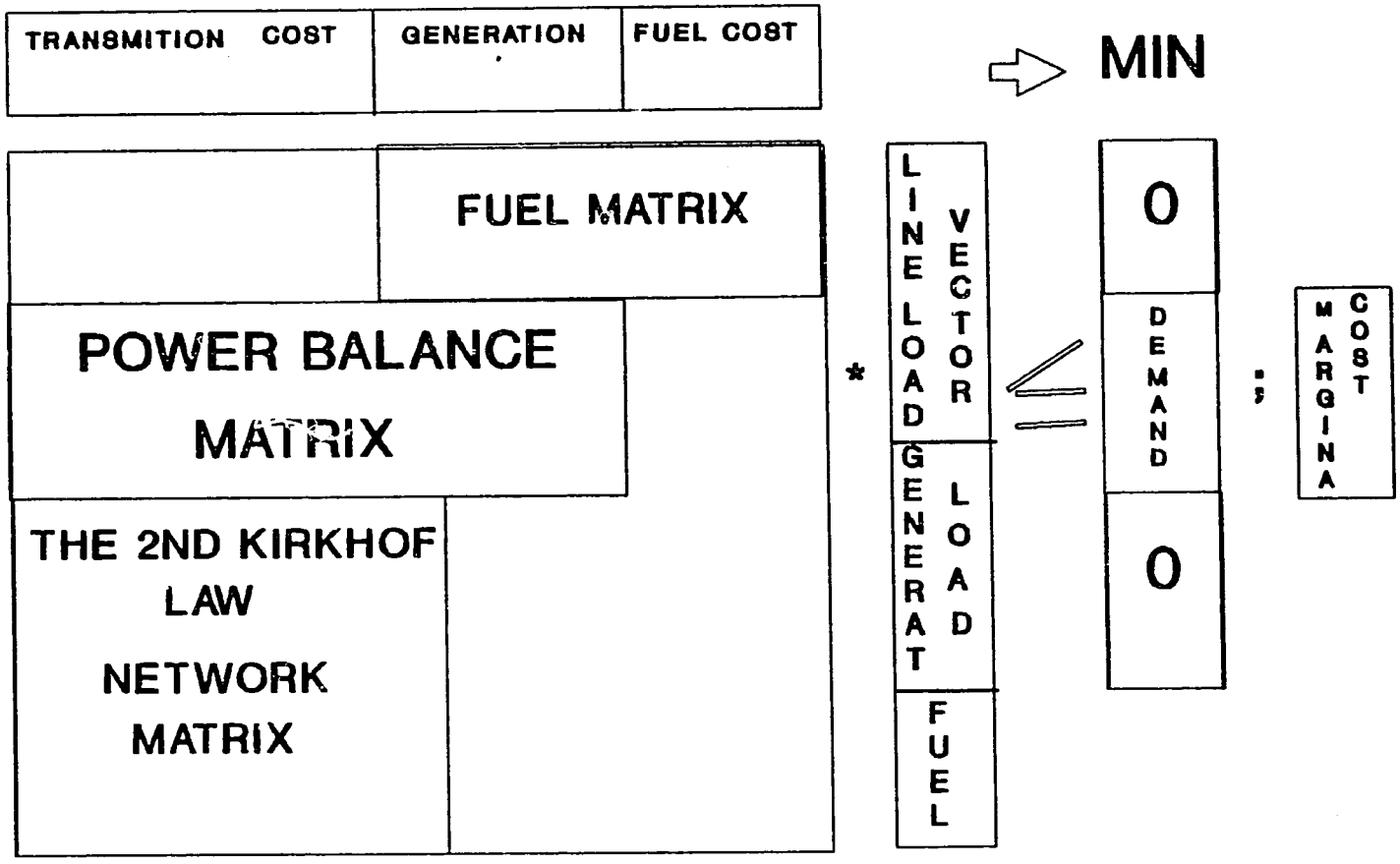
MATHEMATICAL MODEL OF MARGINAL COSTING IN THE POWER SYSTEM

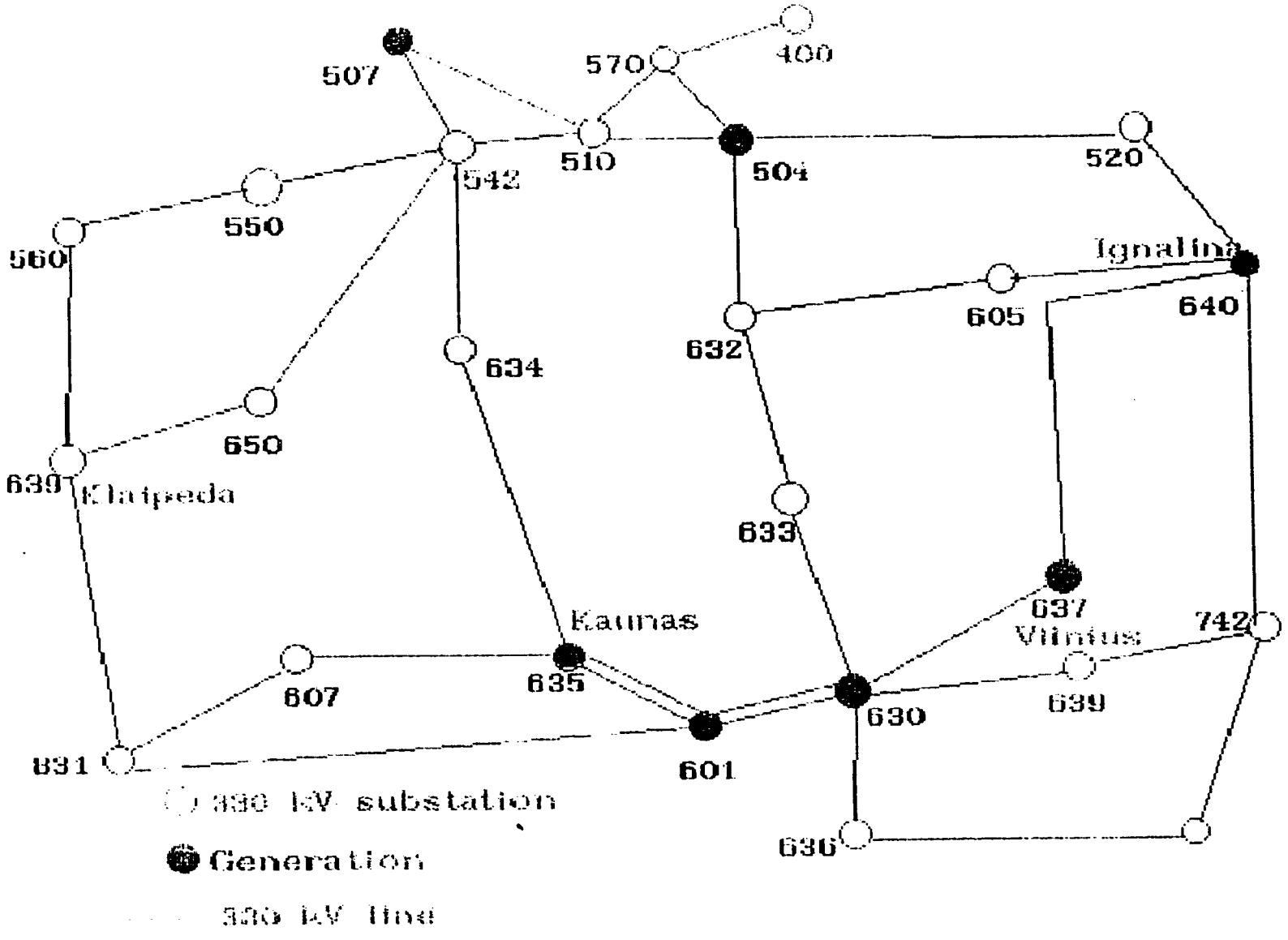


programming software on the mainframe computer EC 1046. The model enables to determine marginal costs in all the points of the power system at every moment of time.

The model evaluates a relative fuel consumption in power plants and energy distribution laws in the grid as also load restrictions. Energy production costss are also evaluated. The model gives marginal costs which reflect an optimal regime of the power system. So optimal load curves of all the units are presented.

The model is an autonomous part of the modelling complex of the energy system. It uses the decomposition principles of Dantzing-Wolf and Benders. These principles enables to arrive at compatible decisions in different subsystems of the energy system in order to reach a global optimum in all the system.

This model could be used broader with transfering it on a PC computer.



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