EnergyPlan: computer model for energy system analysis

version 6

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EnergyPLAN
Computer Model for Energy System Analysis
Version 6.0

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Preface

Since 1999 the EnergyPLAN model has been developed and expanded to the version 6.0.

Initially the model was developed by Henrik Lund and implemented in an Excel spreadsheet. Very soon the model grew huge and, consequently, in 2001 the primary programming of the model was transformed into Visual Basic (from version 3.0 to 4.4). At the same time a number of changes and amendments was made to the model and all the hour by hour distribution data were transformed into external text-files. All in all this reduced the size of the model by a factor 30. This transformation was done in collaboration with Leif Tambjerg and Ebbe Münster (PlanEnergi consultants).

During 2002 the model was re-programmed in Delphi Pascal into version 5.0. And during 2003 the model has expanded into the present version 6.0. Henrik Lund implemented this transformation with the help and assistance of Anders N. Andersen and Henning Mæng (Energy and Environmental Data).

In version 6.0 the model has been expanded with a possibility of calculating the influence of CO_2 emissions end the share of RES when the electricity supply is seen as a part of the total energy system of a region. And further possibilities of analysing different trade options on the external electricity market have been added.

The development of the EnergyPLAN model has been part of two research projects: "Local energy markets" partly financed by the Danish Energy Research Programme (EFP j.nr. 1753/01-0003) and "MOSAIK" partly financed by the Danish Renewable Energy Development Programme (UVE j.nr. 51171/00-0037).

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January 2004

1. Introduction

The main purpose of the model is to design suitable national energy planning strategies for analysing the consequences of different national energy investments. The model emphasises the analysis of different regulation strategies. The analysis is carried out in hour-by-hour steps for one year. And the consequences are analysed on the basis of both different technical regulation strategies and different market economic optimisation strategies.

The model is an input/output model. General input is demands, capacities and choice of a number of different regulation strategies emphasising import/export and surplus production of electricity. Output is energy balances and resulting annual production, fuel consumption, CO_2-emissions and import/exports.

The model is designed to make two different types of analyses. The first one being a technical analysis based on demands and capacities. The second one being an economic optimisation of the behaviour based on further inputs of marginal costs and hour-by-hour price assumptions on the international electricity market (See diagram 1).

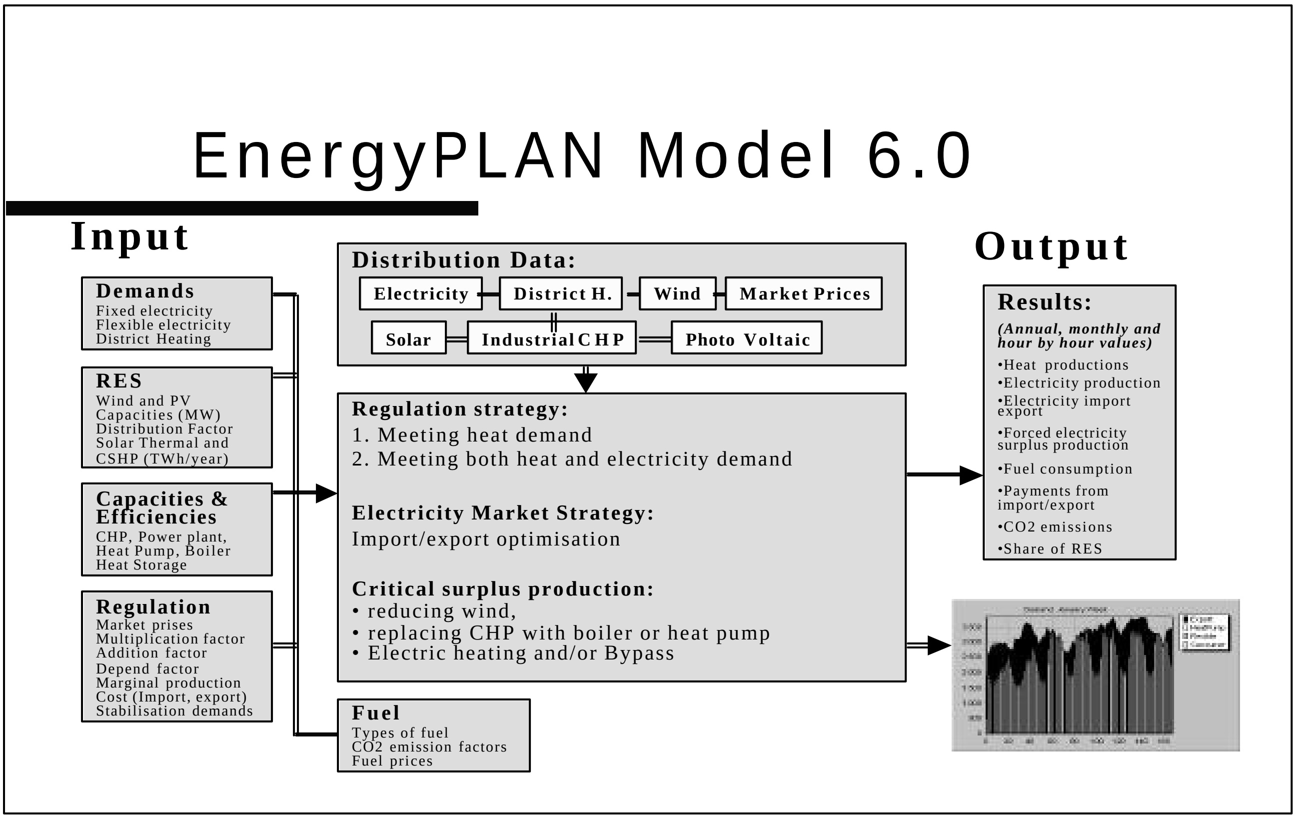


Diagram 1: The EnergyPLAN Model 6.0

2. The EnergyPLAN energy system

The energy system in the EnergyPLAN model is shown in principle in diagram 2.

The Demand system:

- District heating demand divided into I) group of boiler systems, II) group of decentralised CHP systems and III) group of centralised CHP systems
- Electricity demand divided into two different types of fixed demands and three types of flexible demands
- Possibility of adding a fixed external import of export of electricity

The Production system:

For district heating group I, the production system consists of:

- A solar thermal
- A CSHP unit (Combined Steam and Heat Production = Industrial CHP)
- A District Heating Plant (DHP), i.e. a boiler

For district heating groups II and III, the energy production system consists of:

- A solar thermal
- A CSHP unit (Industrial CHP)
- A CHP unit
- A heat pump
- An electric heating unit
- A peak load boiler, and
- A heat storage

Furthermore the total production systems include:

- A Wind Power input divided into on-shore and off-shore
- A Photo-voltaic input, and
- A Power plant (condensed production)

For such an energy system, the model analyses the behaviour in the case of a number of different regulation strategies.

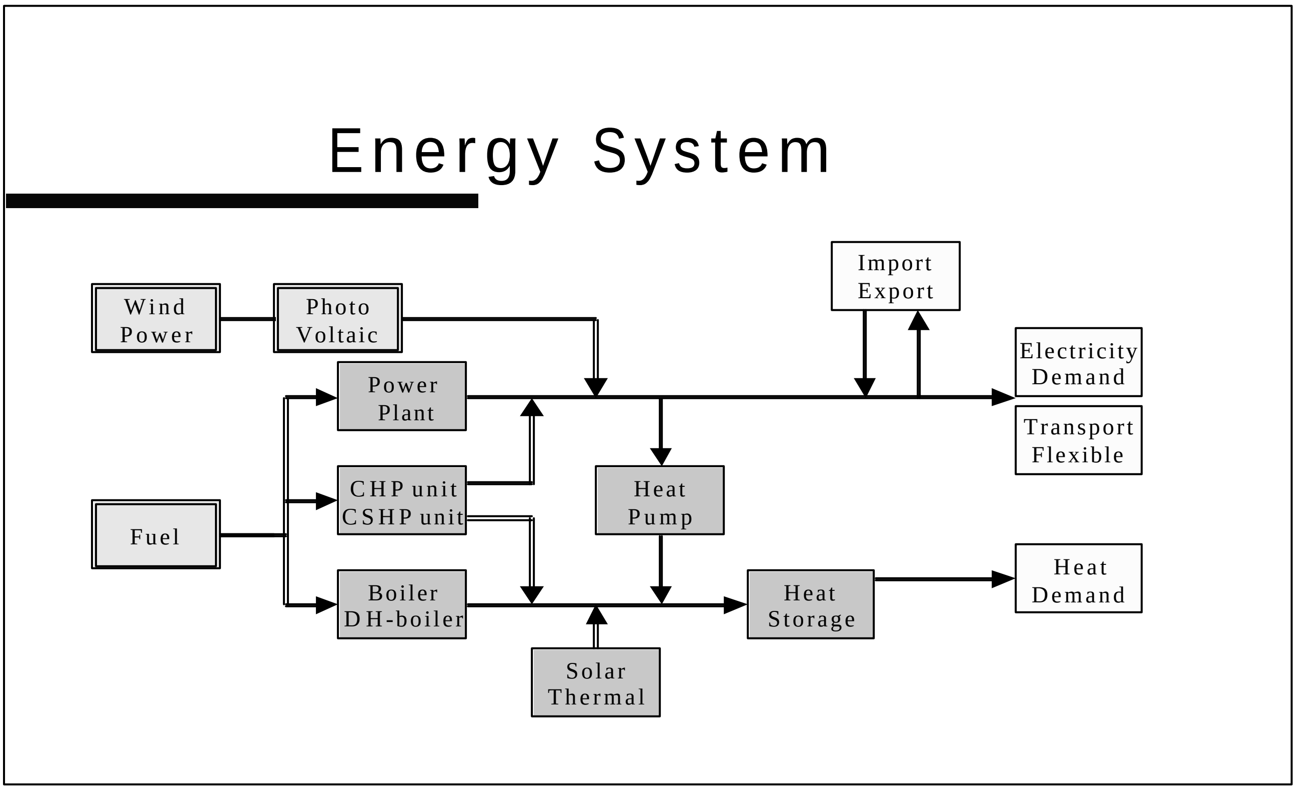


Diagram 2: Principle of the Energy Production System in the EnergyPLAN model

3. Input data

As shown in Diagram 1, the input data of the model is divided into five sets of data: Demands, Renewable Energy Sources (RES), Capacities, Regulation and Fuel.

3.1 Demands

The annual district heating consumption needs to be stated for each of the three DH groups. And the annual consumption of electricity is stated and divided into flexible and fixed demands, and demand for the transport sector, if any. For any flexible electricity demand is also stated a maximum capacity value. As for the rest of the demands, the input is given by an annual value (TWh per year) and a name of an hour by hour distribution data set.

Q_{DH} = District heating (Divided into the three groups described above)
E_D = Electricity demand (Divided into the fixed and flexible types described above)

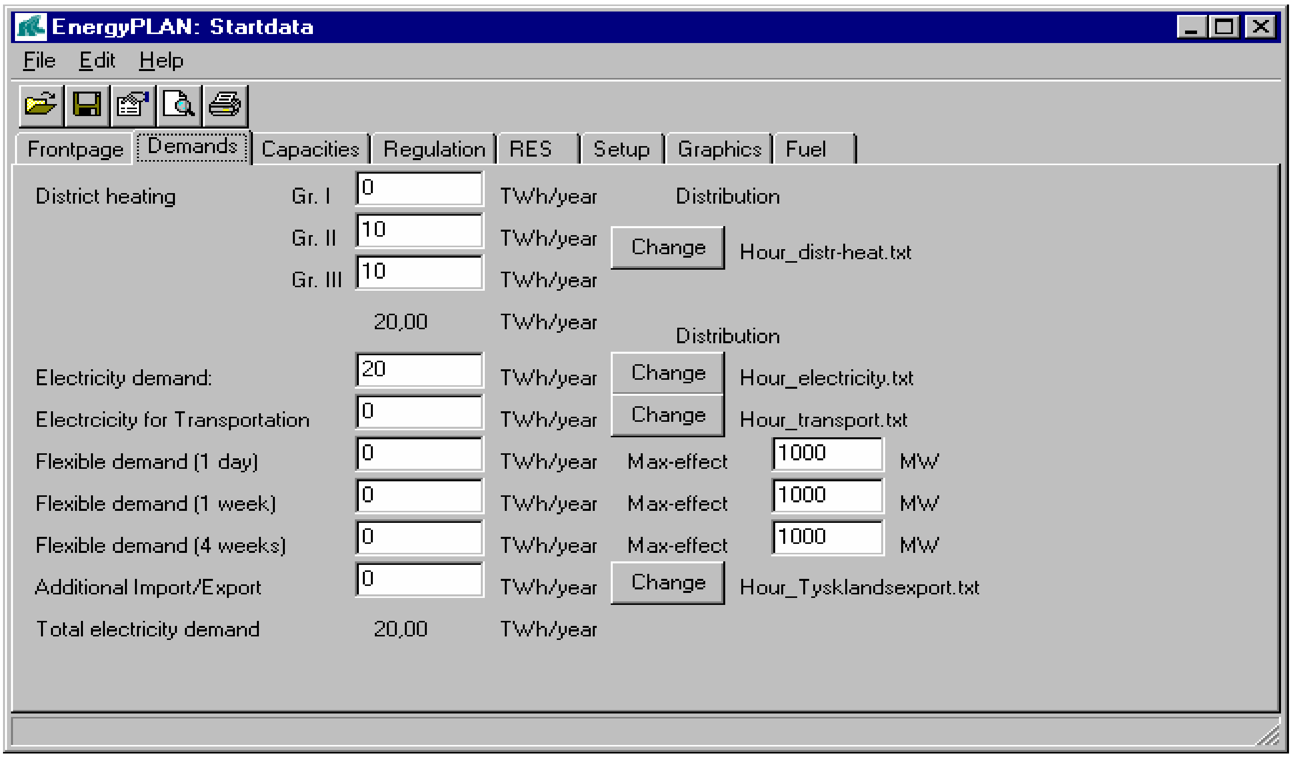


Diagram 3 : Demands input data window

3.2 Renewable Energy Sources (RES)

The input data set defines input from RES and industrial CHP (CHSP) both to the electricity supply and to the district heating supply. The latter being divided into the three district heating groups. Input to the electricity production is given by the capacity of photo-voltaic and wind power, including a moderation factor in order to adjust the relationship between the wind capacity and the correlating electricity production. The RES production is divided into photo-voltaic, wind on-shore and wind off-shore with capacities of their own and wind distribution factors.

Input to district heating production is given for solar thermal and industrial CHP, the latter including input to electricity production as well.

Additional to the above information, the names of the hour by hour distribution data sets are defined for all the inputs.

Cpv, C_W = Photo Voltaic and Wind power capacity (MW) (Divided into on-shore and off-shore)
Fac_W = Wind distribution factor (Factor to change former wind production based on historically PV or wind turbine configurations into production from other configurations, i.e. for example from on-shore wind turbines to off-shore wind turbines).

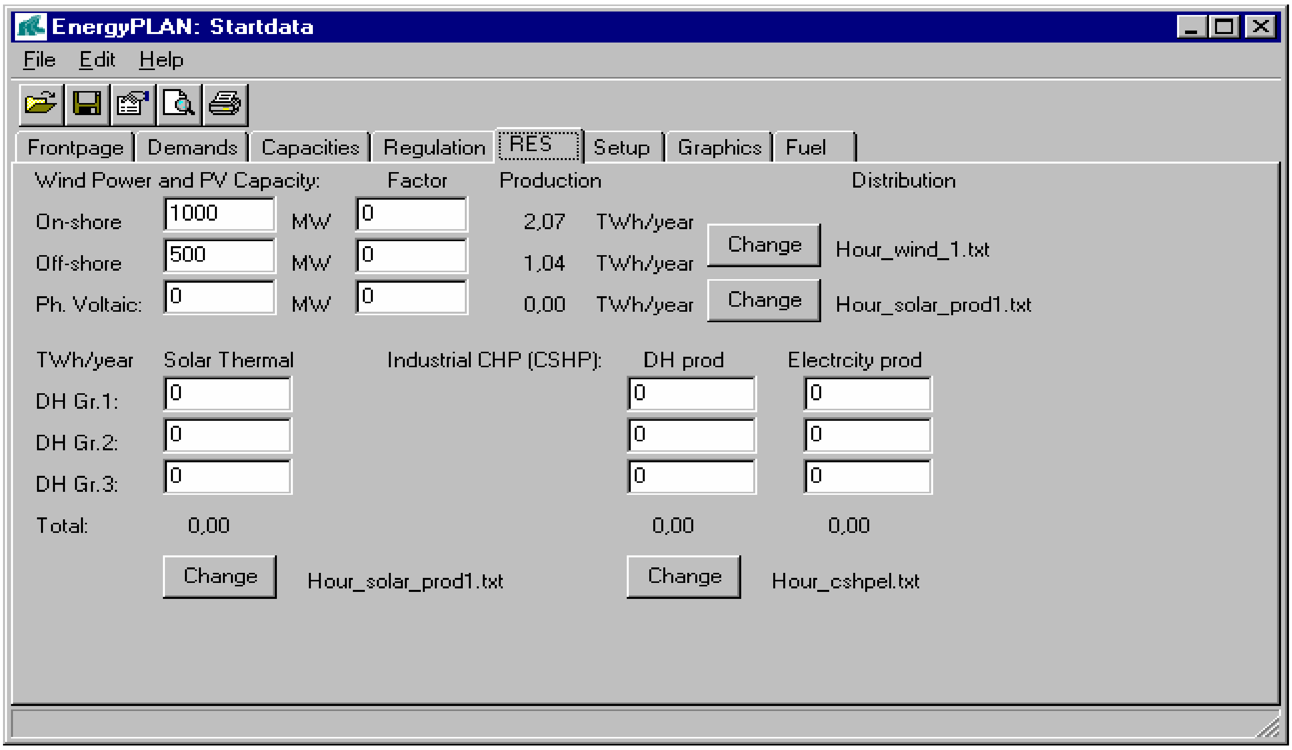


Diagram 4: RES input data window

3.3 Capacities

Capacities (MW electric or MJ/s thermal) and operation efficiencies of CHP units, power stations, boilers and heat pumps are defined as part of this input data-set. Also the size of heat storage capacities are given here.

C_{HP} = Heat Pump capacity (MW)
C_{CHP} = CHP capacity (MW)
C_{P} = Power Plant capacity (MW)
H_{B} = Boiler capacity (MJ/s)
H_{HP} = Heat Pump heat capacity (MJ/s)
H_{CHP} = CHP heat capacity (MJ/s)
C_{HP} = Heat storage capacity (GWh)

C_{P} is the total capacity of power plant capacity and CHP capacity in group III. This is due to the fact that in lack of district heating demand in group 3, the CHP capacity can be turned into purely condensing power plant capacity.

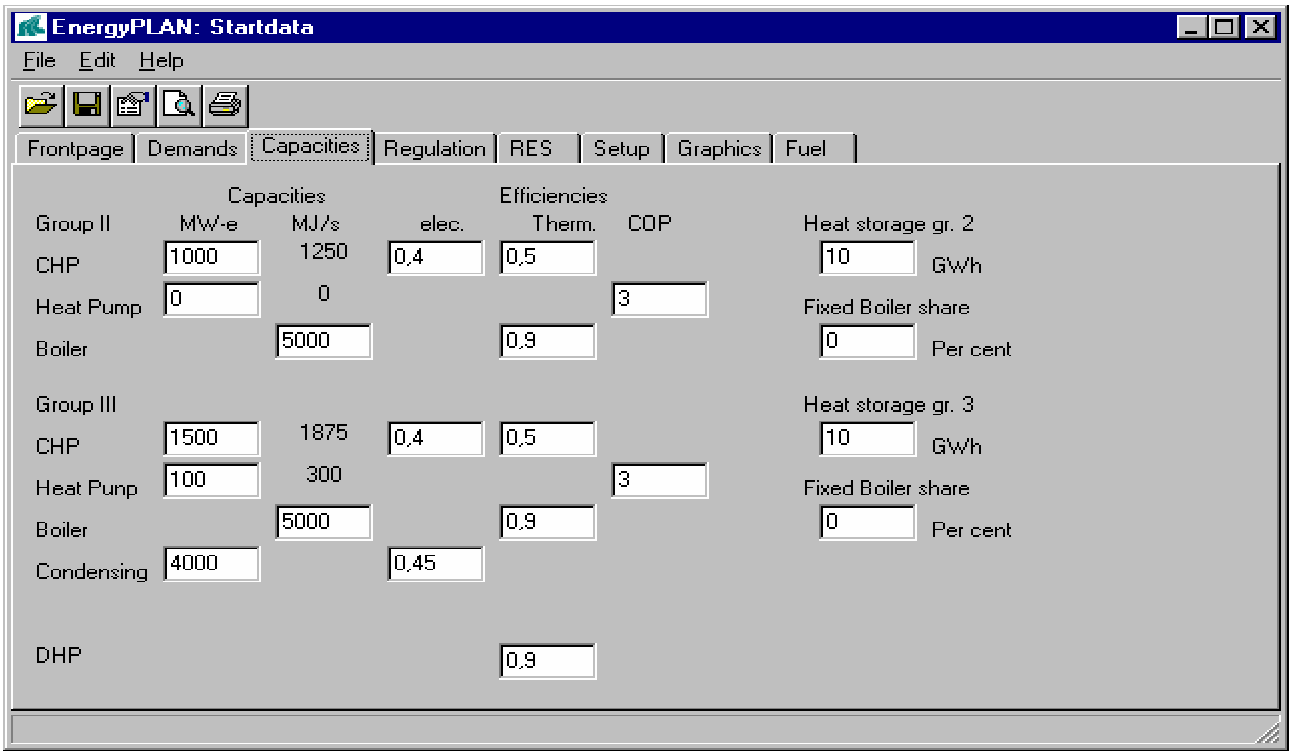


Diagram 5: Computer input data window

3.4 Regulation

This input specifies the choice of different regulation strategies, and defines market prices and marginal production prices. The input also includes some technical limitation.

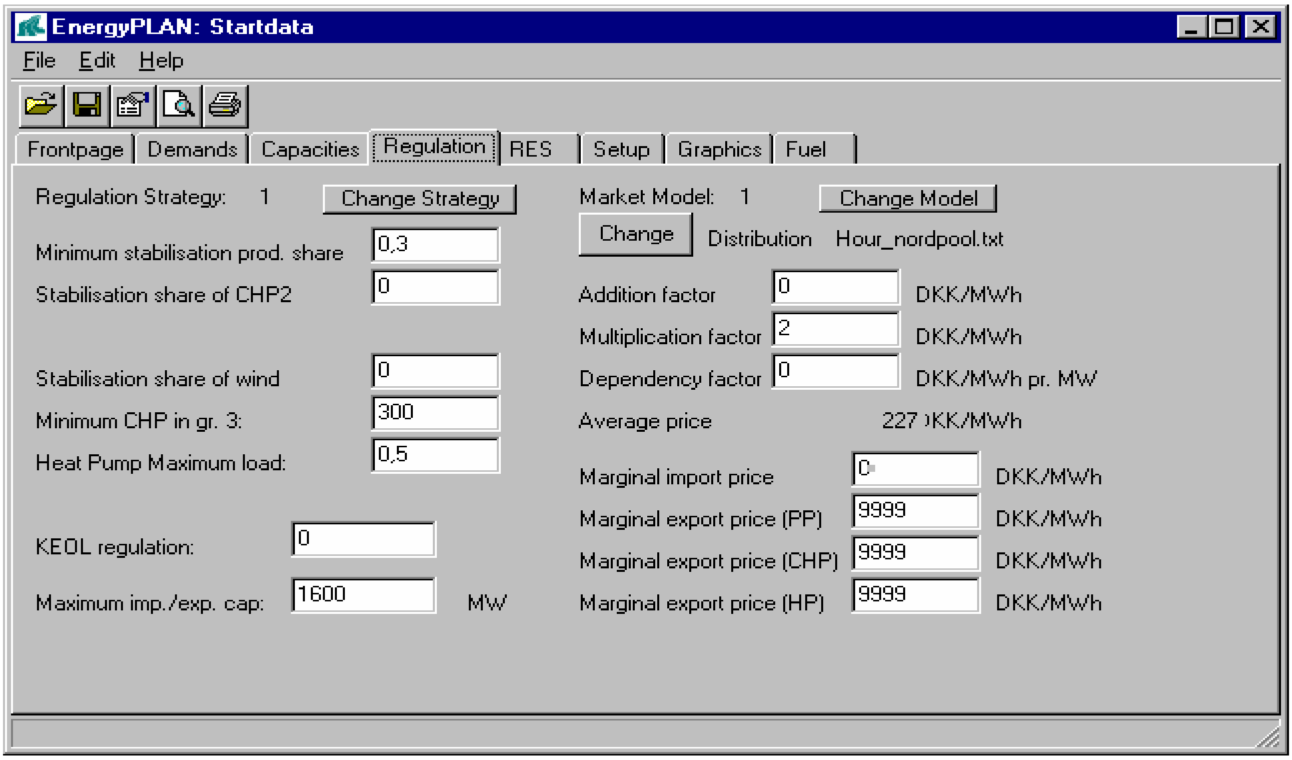


Diagram 6: Regular input data window

A choice between four technical regulation strategies and four market strategies are given. For more detailed information on each strategy please consult chapters 6 and 8.

Also critical surplus production can be removed according to a priority between:
1. Stopping wind turbines (first on-shore then off-shore)
2. Replacing CHP in group 2 with Heat Pumps or Boilers
3. Replacing CHP in group 3 with Heat Pumps or Boilers
4. Electric heating in group 2
5. Electric heating/or bypass in group 3

The five possibilities are activated in a priority. If for instance "KEOL regulation" is stated as 23541, critical surplus production will be removed first by replacing CHP in group 2 and 3, then by electric heating and in the end by stopping wind turbine. For "KEOL regulation" = 51, surplus production is removed first by electric heating only in group 3 and then by stopping wind turbines.

The prices of electricity at the external market are defined by choosing an hour by hour distribution. These prices can then be changed by the following factors: a multiplication factor and an addition factor (DKK/MWh). Moreover, the market can be changed by a factor expressing market-reactions to trade on the market. This factor is expressed in terms of how much the price (DKK/MWh) change per trade (MW).

Short-term marginal production costs can either be stated as input, or in the next section (FUEL input data set) it can be activated for the model to calculate the prices if fuel prices and marginal operation and maintenance costs are given instead. The following marginal costs can be defined:

MC_{import} = Marginal production costs of one MWh electricity less on the Power Plant
MC_{P} = Marginal production costs of one MWh electricity more on the Power Plant
$MC_{B\text{-}CHP}$ = Marginal production costs of one additional MWh by replacing the boiler by the CHP unit
$MC_{HP\text{-}CHP}$ = Marginal production costs of one additional MWh by replacing the HP by the CHP unit

If the import costs are zero and the rest is defined with very high numbers (as for instance 9999 as in the example above) then the model will not trade on the market, end the results are then the results of the technical analysis.

Also a number of technical limitations are defined, namely a) the minimum CHP and power plant per cent of the load in order to remain grid stability, and b) the maximum heat pump per cent of the heat production in order to achieve the specified COP. Finally, the transmission capacity is stated.

3.5 Fuel

This input set defines the distribution of fuel types for each energy unit in each district heating group. Also additional fuel consumption for transportation and industry can be added in order to complete the fuel accounts and the accounts of CO_2 emissions. If fuel prices and marginal operation and maintenance costs are stated then the model can be told to calculate a number of relevant short-term marginal production costs, which will then be used in the strategies of optimising the profits of trade on the external electricity market. If this possibility is activated then the given marginal cost in "REGULATION" will be taken over.

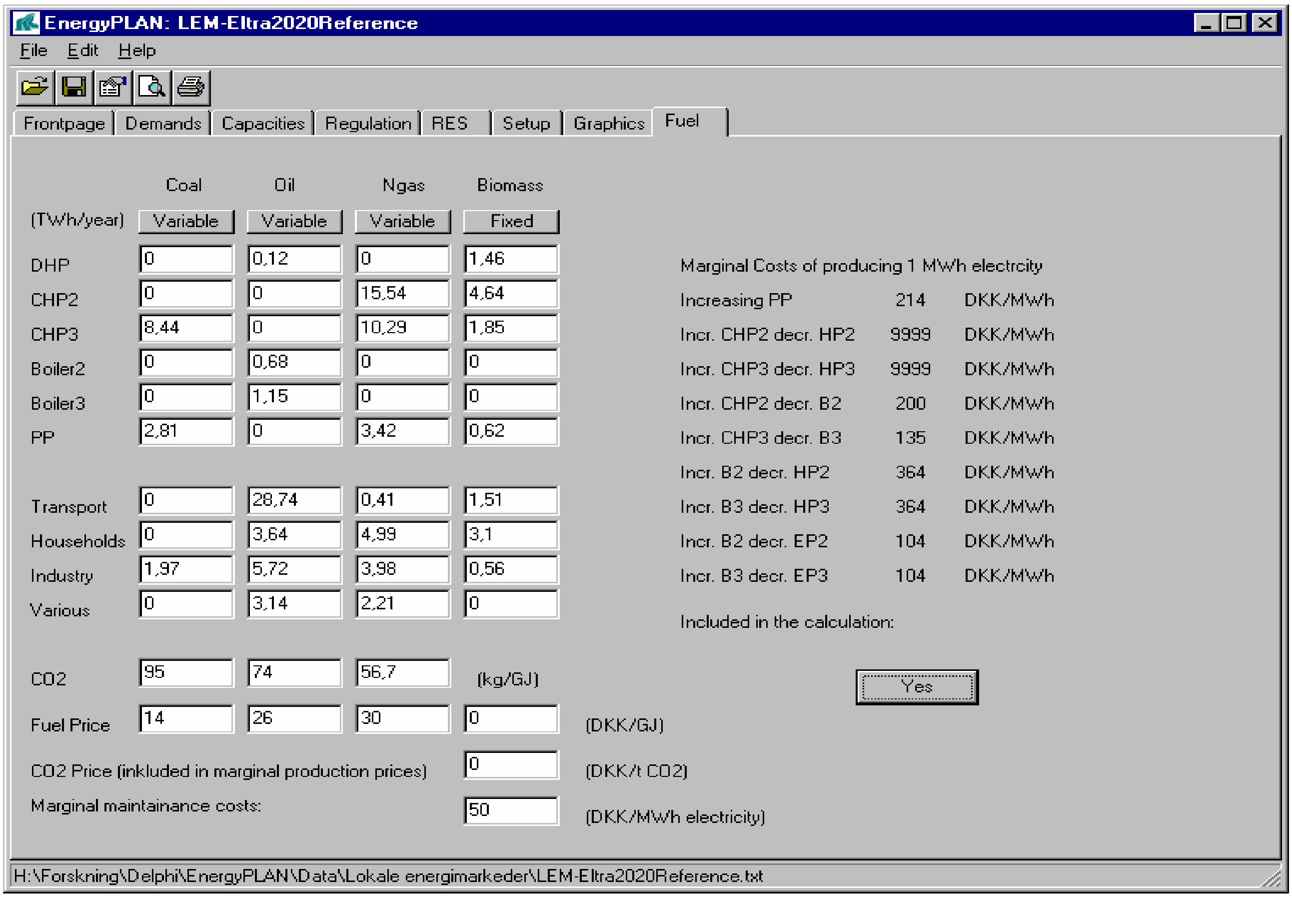


Diagram 7: Fuel input data window

4. Distribution data

For each demand, each renewable energy source and for the electricity market the annual values are distributed into one specific value for each of 8784 hours in one year.

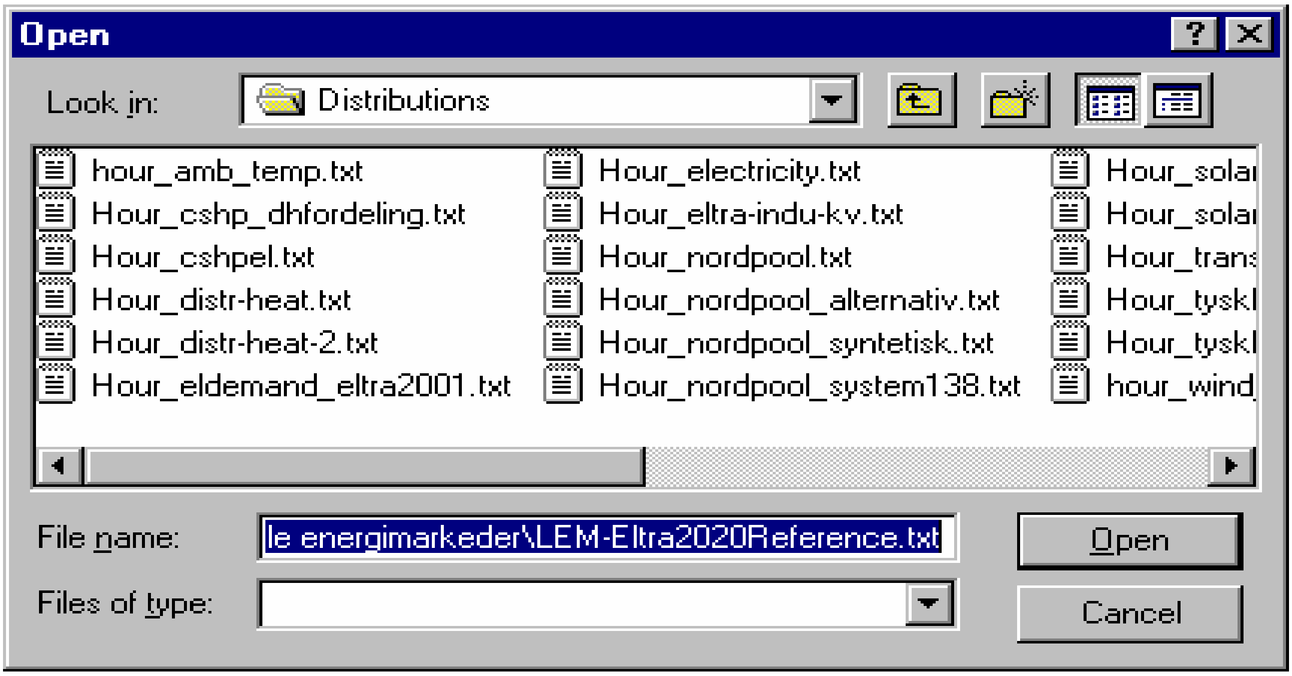


Diagram 8: Distribution data set library window

When starting the model all inputs have distribution data attached. One can change distribution by activating the bottom "Change". Then the following window, illustrated in diagram 8, will arise, in which new distribution data can be chosen from the library. New distribution data can be added to the library, simply by producing a text file with 8784 numbers. All distribution data is calculated relatively to the average value.

The model has got a library including the following distribution data set:

- Hour by hour distribution of a typical Danish electricity demand (Year 2000)
- Hour by hour distribution of a typical Danish district heating demand
- Hour by hour distribution of photo-voltaic and solar thermal
  (Typical Danish distribution based on the Danish Test Reference Year (TRY))
- Hour by hour distribution of industrial CHP
- Hour by hour distribution of 3 wind years: 1991 (mean), 1994 (high), 1996 (low)
- Hour by hour distribution of NORDPOOL prices in the first year
  (summer of 1999 till summer of 2000)

Four of the “hour by hour” distribution data sets are illustrated in diagram 9.

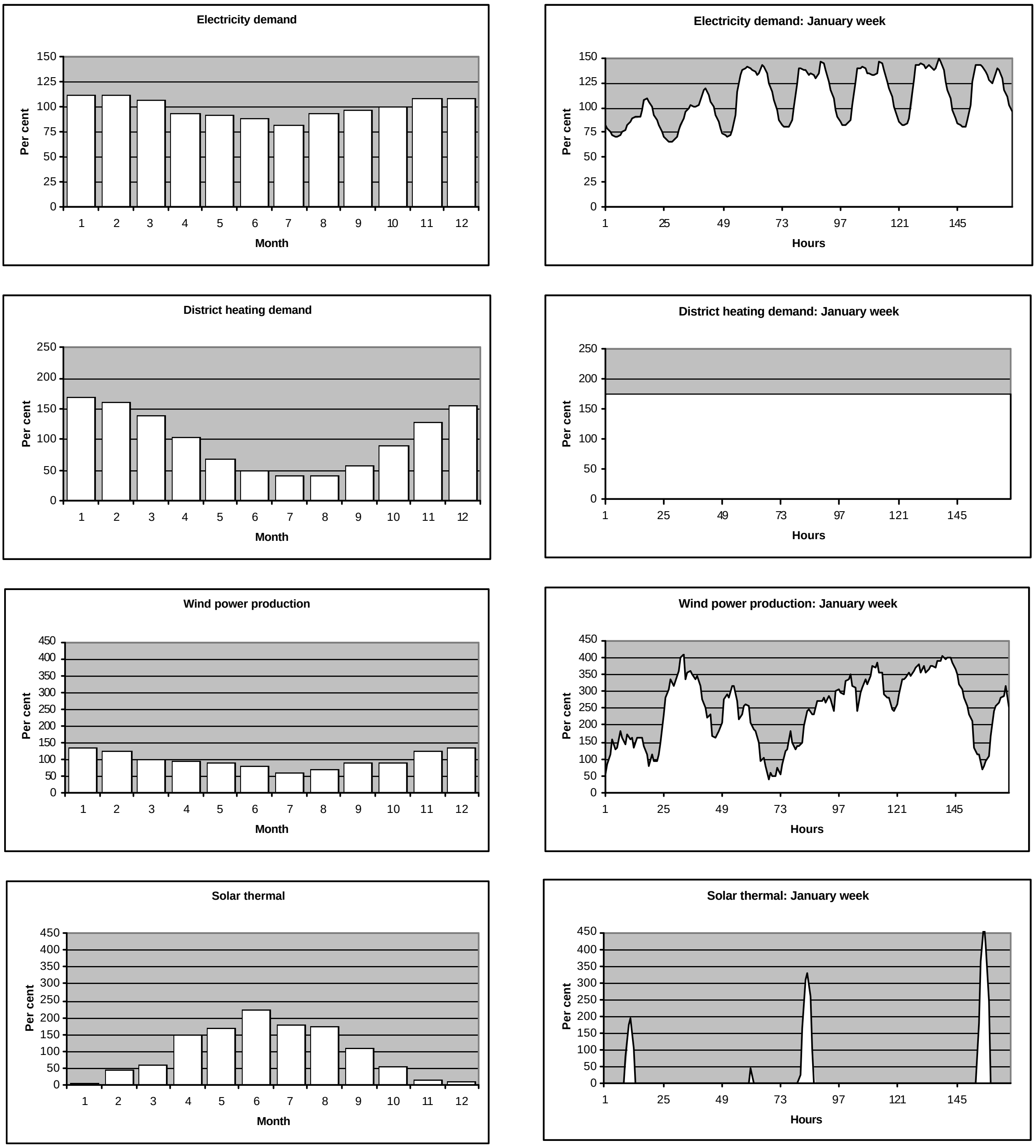


Diagram 9: Example of distribution data sets

5. Initial input data calculations

The model starts by making a number of initial calculations on the input data. First, the model calculates hour by hour values of the following heat demands and types of production:

q_i (MWh/h): district heating demand in 3 dh groups
q_{solar} (MWh/h): Solar thermal production in 3 dh groups
q_{cshp} (MWh/h): CSHP heat production in 3 dh groups

And the following electricity demands and types of production:
e_i (MWh/h): electricity demand
e_f (MWh/h): fixed import/export
e_w (MWh/h): wind power production divided into onshore and offshore
e_{pv} (MWh/h): photo-voltaic production.
e_{cshp} (MWh/h): CSHP electricity production

The demands are found simply by distributing the annual demands according to the internal hour by hour distributions. The district heating demand and the heat production from solar thermal and CSHP are divided into the 3 district heating groups.

5.1 Wind Power and Photo Voltaic modifications

The wind power production is found by multiplication of the wind capacity by the distribution of the chosen wind year. The production from the wind years in the library has been found from historically wind turbine configurations leading to production of either 2064, 2303 or 1799 kWh/year per kW installed capacity (See diagram 10).

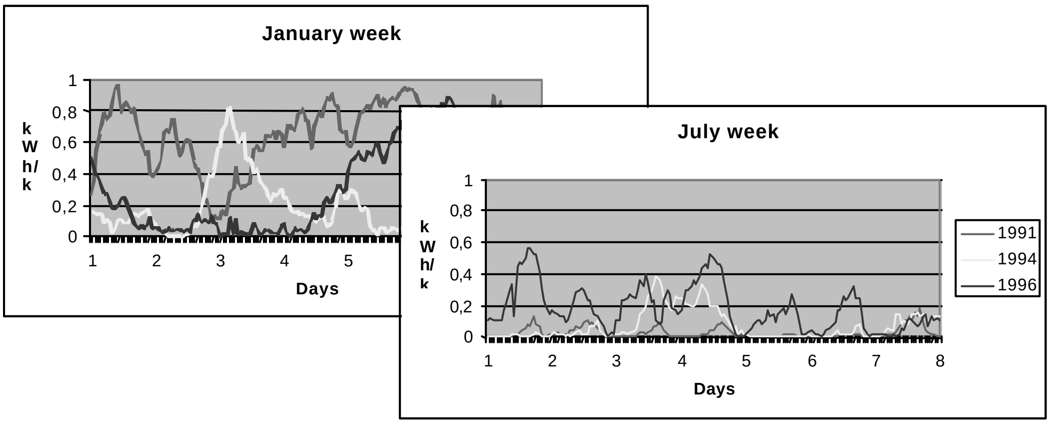
However, different future wind turbine configurations would lead to either lower or higher production in the same wind years. Therefore, a factor can be added in the input in order to change the production from the same wind capacities and the same wind year. The factor changes the production in a way that it remains the same in hours with either no production or full production while the rest of the values are moderated relatively:

$$e_{W-new} = e_{W-old} * \frac{1}{1 - Fac_W * (1 - e_{W-old})}$$

The same procedure is used for any modification of photo-voltaic.

Wind Power Distribution data

Year	kWh/kW pr. year
1991	2064
1994	2303
1996	1799
Average	2102



Hour by hour distribution data produced on the basis of actual wind year: 1991 (mean), 1994 (high) and 1996 (low)

Diagram 10: The model has three different wind production distributions in the library

5.2 Electricity demand modifications (flexible demand)

The model uses an hourly distribution of the electricity demand specified in the input as an external input-file. A typical Danish distribution based on statistic information from year 2000 is provided as an option (Shown in diagram 9). Or other external input files can be created. The electricity demand is distributed according to the specified distribution.

Any new demands caused by use of electricity for transport (batteries and/or hydrogen) or by other purposes can be specified in the inputs. The same goes for fixed import/export, which can be defined in the same way. Meanwhile electricity for transport can be made flexible. The same routines can be used for defining a certain per cent of the demand as flexible demand. This allows for analysing the consequences of introducing flexible demands for cooling etc. within Industries and/or households.

An additional electricity demand can be made flexible within short periods according to the following four categories:

A. Demand following a specified distribution (typically battery cars being charged during the night)
B. Demand freely distributed over a 24hour period according to the actual electricity balance. (Similar to the above, but with the added possibility of concentrating the demand to the ac tual peak hours for e.g. wind production - requires a method of communicating this knowledge to the consumers)
C. Demand which can be distributed freely over a week according to the actual electricity balance (Similar to the above - relevant for consumers with extra battery capacity and for hy drogen operated vehicles)
D. Demand which can be distributed freely over a four week period (similar to the above - relevant for hydrogen operated vehicles. Optimal distribution of demand for a period of this length requires a long-term prognosis for the electricity balance to be transmitted to the con sumers. As this prognosis is partly based on a weather prognosis it is hardly possible today, as four-week prognoses are not sufficiently reliable at present)

For the category A, B and C, the distribution of the demand within the given intervals is determined one by one according to an evaluation of the balance between the 'fixed' electricity production (wind, photo-voltaic and CHP) and the following demands:

The basic demand from consumers and industries: e_i
The demand of fixed import/export: e_f
The demand from heat pumps: e_{HP}
The yearly average of demand for transport of the given category: E_{Tran} / 8784 MWh

The distribution of demand within the interval is made in order to follow the variation of this balance with two limitations:

A. It must be positive at any time
B. It should be below a given maximum. $C_{TR,n}$ (defined in the input)

A normalisation of the variation ensures that the average demand for the period equals the yearly average.

Part of the existing demand can be specified to be flexible in the same way as the transport demands of category b, c, and d. Typically, these flexible demands will be connected to either room heating or to cooling processes (air conditioning or cold stores). The flexible demands can be specified for the same three periods as the transport demands. For each period and for each type (cooling, heating), the max capacity must be stated. Note that the fixed demand should be decreased in order not to increase the total demand.

The effects on the hourly distribution of the total electricity demand are calculated the same way as for the transport demands. In diagram 11 and 12 is shown an example of how flexible demand is reducing differences in the balance between supply from CHP and Renewable energy and demand. The example is given for the following situation:

Electricity demand	= 33 TWh
District heating	= 20 TWh
Wind Power	= 2000 MW
CHP	= 2000+3000 MW-el
HP	= 300 + 500 MW-el

In diagram 11 is illustrated how this situation in a three day period in January has got a continuously CHP production of approx. 3200 MW, and on top of this a wind production increasing the total production to between approx. 3500 and 5000 MW.

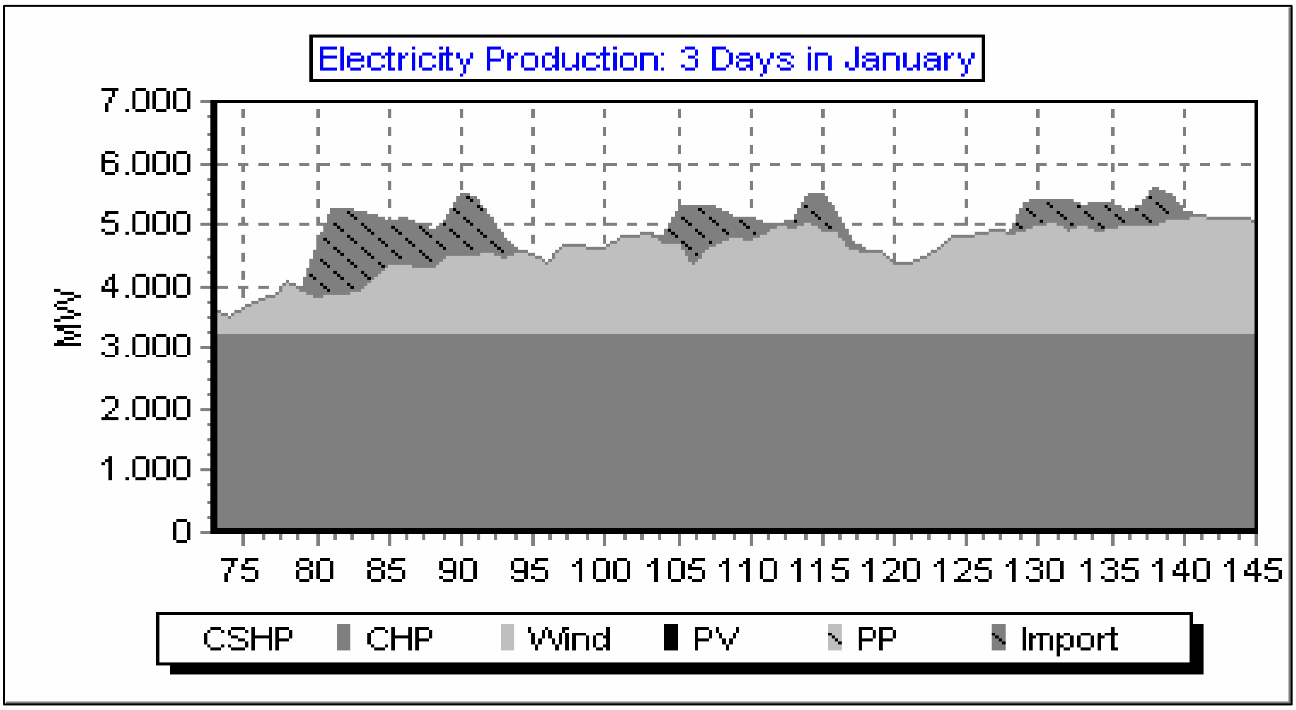


Diagram 11: Electricity Production from CHP, Wind and Import 3 days in January

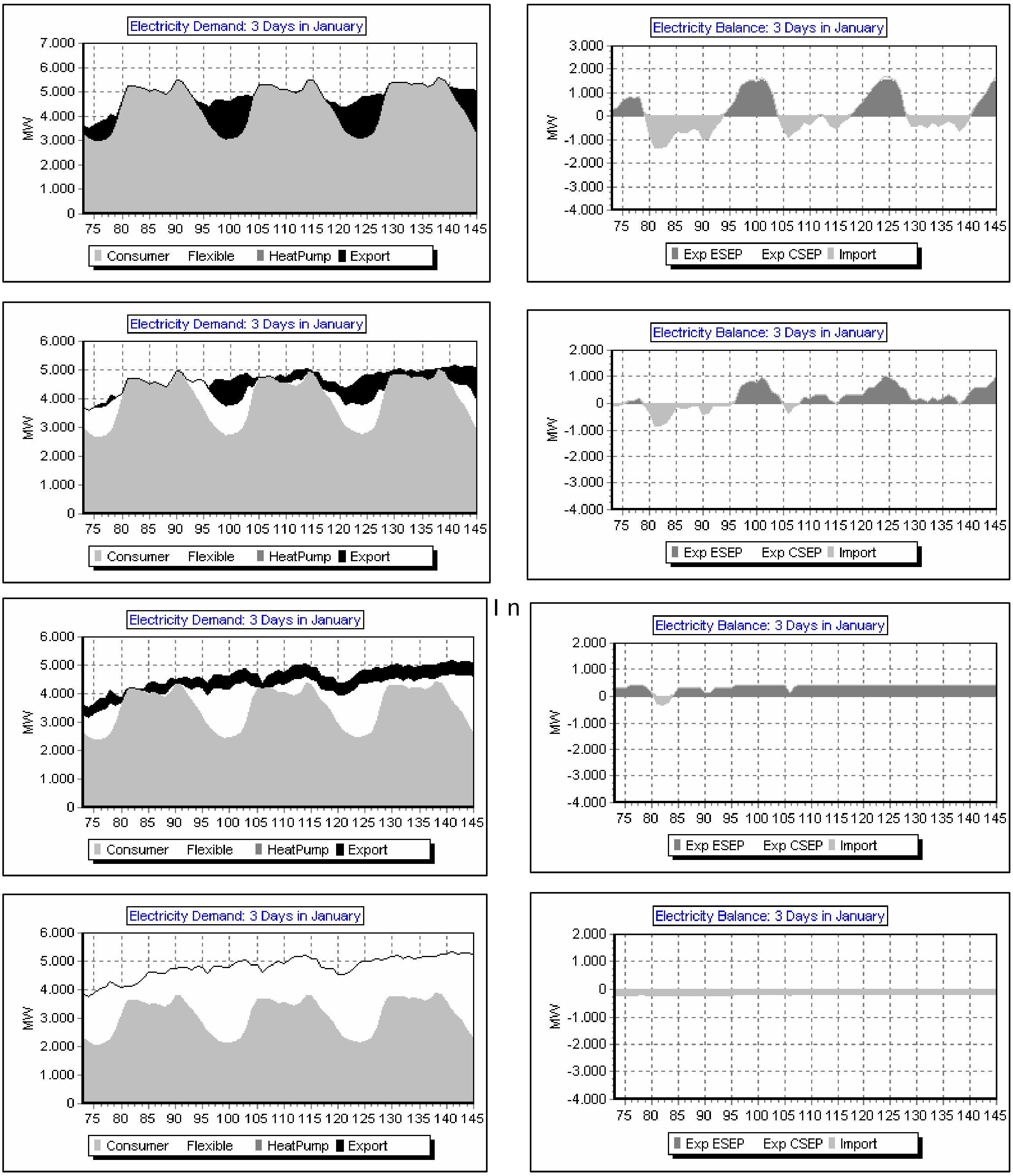


Diagram 12: Example of flexible demand

the left top of diagram 12 is shown the demand (in the case of no flexible demand) and to the right the resulting difference in the balance between supply and demand. The latter diagram is found simply by subtracting the demand and the supply from diagram 11. It can be seen how there is a surplus production during night hours and a lack of supply during day hours, fluctuating along with the variations in the wind production.

In the next three levels of diagram 12 more and more demands have been changed in the input to flexible demands. In the second level 10 per cent is made flexible within a day. In the next level additional 10 per cent is made flexible within a week. And in the last picture, additional 10 per cent is made flexible within a four-week period. It can be seen how such flexibility is able to make the balance between supply and demand better and better.

5.3 Market price modifications

For the economic optimisation, the market prices are found from the specified hour by hour price distribution (NP_i) when modified in the following way:

p_i (DKK/MWh) = $NP_i * P_a + Fac_{depend} * D_{trade}$

where Fac_{depend} is an input factor to set the level of dependence of the market on the market price and D_{trade} is the trade on the market. Import is calculated positive and export is negative, resulting in an increase in the market price in case of import and a decrease in case of export.

5.4 District heating production

In group I heat for district heating is produced by:

Solar Thermal: q_{solar}
Industrial CHP (CSHP): qcshp
District heating plants with boilers: q_{DHP}

The production from solar thermal and CSHP is given for each hour by the input data and the respective distribution sets. The production from the boiler is found as the difference between demands and solar/CSHP types of production:

$q_{DHP} = q\ i - q_{solar} - q_{CSHP}$

6. Energy system analysis

Based on the modified "hour by hour distributions" described above and the rest of the input data, the model calculates electricity and heat production depending on the choice of regulation strategy.

6.1 Regulation strategy I: meeting heat demands

In this strategy all heat producing units are producing solely according to the heat demand.

Technical analysis

Heat for district heating is produced by:

1. Solar Thermal: q_{Solar}
2. Industrial CHP: q_{CSHP}
3. Heat plant CHP: q_{CHP}
4. Heat pumps: q_{HP}
5. Boilers at CHP-plants: q_B

For district heating groups 2 and 3, the units are given priority according to the sequence shown above on an hourly basis. The production from solar thermal and CSHP is given for each hour by the input data and the respective distribution sets. For the heat plant CHP's and the heat pumps, the following limitations are used:

Maximum capacity of CHP and HP
Maximum share of heat pumps compared to the total heat demand: $S_{HP/tot}$

(This limitation corresponds to the fact that heat pumps should be used for the production of low temperature heat only).

The electricity production from CHP's, e_{CSHP} and e_{CHP}, and the consumption from heat pumps, e_{HP}, can now be found by using the assumption for efficiencies. The electricity production at the condensation power plants, e_{PP}, and the possible export of electricity, e_X, are determined by the following steps:

Step 1

The electricity consumption is adjusted by any use of:

- electricity for heat pumps (determined above): e_{HP}
- electricity for transport: e_{TR}
- influence of flexible elec. demands: e_F

$e_{ia} = e_i + e_{HP} + e_{TR} + e_F$

Step 2

The production at the condensation plants is determined as the bigger of the following two values:

A. The difference between the adjusted consumption and the production given by the wind and the heat demand:

$e_{PP} = e_{ia} - e_W - e_{pv} - e_{CSHP} - e_{CHP}$

B. The minimum production necessary to fulfil the requirement of stabilising the grid:

$$e_{PP} = ((e_W + e_{pv} + e_{CSHP} + e_{CHP}) * S_{stab/tot} - (e_{CHP} + e_{CSHP}) * S_{stab/CHP} - e_w * S_{stab/wind}) / (1 - S_{stab/tot})$$

(The necessary share of power plants with stabilising ability of the total production minus the share of the total CHP production and the wind production, which are assumed to have stabilising ability). In case e_{PP} exceeds the specified maximum value C_P, the necessary electricity production is imported.

Step 3

The export of electricity can now be calculated as:

$e_x = e_{PP} + e_{CSHP} + e_{CHP} + e_W - e_{ia}$

The export is divided into two categories: 1) Critical export, e_{cx} and 2) exportable export, e_{ex}. Critical export appears when the export increases the maximum capacities of the grid connections abroad.

Economic Optimisation

The production by condensation power plants was calculated above to:

A. Meet the demand (avoid import of electricity)
B. Provide the necessary stabilisation of the grid.

In this section this production is optimised according to export/import prices at the Nordpool exchange, p_i.

If this price in a given hour is lower than the marginal production costs for the condensation plants AND the corresponding production exceeds the level necessary of stabilisation, it is possible to replace this surplus by imported electricity, e_P. By doing this, the maximum transmission capacity of import and the minimum production with stabilising effect are observed.

The costs of import are calculated as:

p_{imp} (DKK/MWh) = p_i + Fac_{depend} * D_{trade}

where p_i is the system market price (see section 5.3), Fac_{depend} is an input factor to set the level of dependence on the market price, and D_{trade} is the trade on the market.

Import is calculated positive and export is negative, resulting in an increase in the market price
If the choice of having the model calculate all relevant marginal cost is activated (See section 3.5.) then these numbers are used in the optimisation process. If this choice is not activated then the input from section 3.4 is used. If these input are stated zero for import and high for the rest of the inputs this means that the market optimisation will have no influence on the result. In such case the regulation strategy is purely technical.

6.2 Regulation strategy II: meeting both heat and electricity demands

In this section export of electricity is minimised mainly by the use of heat pumps at combined heat and power plants. This will increase electricity demand and decrease electricity production simultaneously as the CHP units must decrease their heat production.

By the use of extra capacity at the CHP plants combined with heat storages, the production at the condensation plants is minimised by replacing it with CHP production.

The following yearly distributions are the same as for strategy I:

- All demands including transport and flexible demands
- Heat and electricity production of industrial CHP plants
- Heat production of heat plants with boilers
- Electricity production from wind turbines

The electricity production by CHP, $\mathbf{e_{CHP}}$**,** must at any time be lower or equal to the maximum capacity, C_{CHP}, and to the capacity corresponding to the heat demand left by the industrial CHP and the boiler plants. Within these limits the value is found to be the highest result of the following two considerations:

1. The capacity which can ensure stability of the grid together with any stabilising effect of the windturbines but without relying on any effect from condensation plants:

   $e_{CHP,II,A}$ = (e_{ia} * $S_{stab/tot}$ - e_W * $S_{stab/W}$) / $S_{stab/CHP}$ - e_{CSHP}

2. The capacity which will be the result of reducing the CHP production found by strategy I, $e_{CHP,I}$, in order to minimise the electricity export found by strategy I, $e_{x,I}$. The necessary reduction will depend on whether the heat pumps at the CHP plants are already operating at

maximum capacity. (For all hours this is determined as either the technical limit, C_{HP}, or by the maximum share of the total heat demand, $S_{HP,tot}$). If this is not the case, the reduction in heat production caused by the reduction in electricity production can be balanced by an in crease in heat production by the heat pumps. This will also reduce the electricity export. As a result the necessary reduction is reduced by a factor

$$1 + H_{CHP}/C_{CHP} \; * \; C_{HP}/H_{HP}$$

If the heat pumps are already operating at maximum capacity, the CHP production will have to be reduced by the size of the electricity export, $e_{x,I}$.

For these reasons the reduction has to be calculated in two steps:

A. Reduction of CHP plus increase of HP:

$$e_{HPmax} = \min(C_{HP} \; ; \; q_i * S_{HP/tot})$$
$$e_{CHP,red,a} = \min \left(e_{x,I}/(1 + H_{CHP}/C_{CHP} \; * \; C_{HP}/H_{HP}) \; ; \; (e_{HPmax} - e_{HP}) * H_{HP}/C_{HP} * C_{CHP}/H_{CHP} \right)$$
$$e_{HP,inc,a} = e_{CHP,red,a} * H_{CHP}/C_{CHP} \; * \; C_{HP}/H_{HP}$$

B. Any further reduction of CHP only:

$$e_{CHP,red,b} = e_{x,I} - e_{CHP,red,a} - e_{HP,inc,a}$$
$$e_{CHP,II,B} = e_{CHP,I} - e_{CHP,red,a} - e_{CHP,red.b}$$

These calculations are performed for groups 2 and 3 separately, but with due consideration on total stabilisation demands, etc.

After having determined the production at the CHP plants as maximum, ($e_{CHP,II,A}$; $e_{CHP,II,B}$) the production at the heat pumps and the boilers are calculated the same way as in strategy I.

The electrical production by condensation plants, $e_{PP,II}$ **,** is determined as the necessary production to meet either the electricity demand or the demand of stabilisation the same way as it was done in strategy I.

The electricity export has now been reduced as much as possible under the given constraints.

Economic Optimisation

The technical operation strategy can be optimised either by raising exports or by raising imports.

If the market price is higher than the marginal cost of replacing the boiler and/or the heat pump by the CHP, exports should be increased if capacities allow it. The potentials are found in the following way:

Potential of raising electricity production from replacing the boiler by the CHP unit (X1):

If $(MC_{B\text{-}CHP} < p_i)*(q_{CHP} < H_{CHP})*(q_B > 0)$
Then $X1 = MIN(H_{CHP} - q_{CHP}, q_B)$
Else $X1 = 0$

Finally, economic optimisation, regarding the production at condensation plants, is performed as described for strategy I. By doing this as the last step also ensures that the criteria of grid stabilisation is fulfilled.

Likewise in regulation strategy I, if the choice of having the model calculate all relevant marginal cost is activated (See section 3.5.) then these numbers are used in the optimisation process. If this choice is not activated then the input from section 3.4 is used. If these inputs are stated zero for import and high for the rest of the inputs, this means that the market optimisation will have no influence on the result. In such case the regulation strategy is purely technical.

6.3 Regulation strategy III: meeting both heat and electricity demands and reducing CHP also when it is partly needed for stabilisation reasons (replacing by PP)

Regulation Strategy III is the same as strategy II apart form one thing.

In strategy II CHP will not be reduced (and the heat production replaced by heat pumps), if CHP-units are needed for stabilisation reasons.

Meanwhile, in some situations (when the CHP-stabilisation factor is below 100 per cent) surplus production can be minimised further by reducing CHP and replacing heat production by heat pumps and boilers and stabilisation demands by PP units.

Consequently, in strategy III CHP units are reduced even when stabilisation demands call for replacement with PP-units.

The choice between strategies II and III is a choice between better efficiency in the system and less surplus production.

Economic optimisation is done the same way as for regulation strategy II.

6.4 Regulation strategy IV: meeting the triple tariff

Regulation strategy IV is the same as strategy I apart from one thing. In regulation strategy IV the CHP units in group 2 is meeting the Danish triple tariff instead of meeting the heat demand on a production being the same during the day.
The electricity production from CHP units in group 2 are located according to a priority of peak load, high load and low load. And the periods of the triple tariff are defined simply as:

- Peak load during weekdays between 8.00 and 12.00 (plus 17.00-19.00 in the winter)
- High load during weekdays between 6.00 and 21.00, and
- Low load in the rest of the time

Regulation strategy I and IV are the same in the sense that in neither cases the CHP adjust their production according to the fluctuations in the wind power.

Economic optimisation is done the same way as for regulation strategy I.

6.5 Heat storage utilisation

To improve the possibilities of minimising the electricity export, heat storage capacity is included in the model for each of district heating groups 2 and 3.

In two situations the storage can be loaded:

A: Increasing the use of HP in situations with electricity export
B: Moving the electricity production from condensing plants, e_{pp} to CHP plants

In two situations the storage can be unloaded:

C: Reducing the CHP production in situations with electricity export
D: Reducing the boiler production

B is secondary to A and D is secondary to C. The four loading and unloading cases are used in the following order: C-A-B-D. These series are then used in the following order:

1: Critical electricity export e_{cx} and CHP in group 3
2: Critical electricity export e_{cx} and CHP in group 2
3: Economical electricity export, e_{ex} and CHP in group 3
4: Economical electricity export, e_{ex} and CHP in group 2

In order to achieve balance, the calculations are performed over a series of two-week periods, where the storage content at the end of the first year is equal to the storage content at the beginning of the second year.

The four loading and unloading situations are calculated as follows:

A. Loading by increasing the use of HP in situations with electricity export

First, the smaller of the potential increase in district heating production from HP, HP_{pont} and the potential increase in storage content, St_{pont} is determined.

$$HP_{pont} = \min(e_x ; C_{HP}-e_{HP}) * (H_{HP}/C_{HP}) * ((p_i<MC_P) \text{ or } (e_x=e_{cx}))$$

The last parenthesis states that the market price, p_i has to be below the marginal production cost of one MWh electricity on the power plant and, MC_p or the electricity export in question should be critical export; otherwise the HP_{pont} is set to zero.

$$St_{pont} = H_{STORAGE} – Q_{STORAGE}$$

New values can now be calculated:

$$e_{HP\text{-}new} = e_{HP\text{-}old} + \min(HP_{pont} ; St_{pont}) * (C_{HP}/H_{HP})$$
$$e_{x\text{-}new} = e_{x\text{-}old} - \min(HP_{pont} ; St_{pont}) * (C_{HP}/H_{HP})$$
$$q_{HP\text{-}new} = q_{HP\text{-}old} + \min(HP_{pont} ; St_{pont})$$
$$Q_{STORAGE\text{-}new} = Q_{STORAGE\text{-}old} + \min(HP_{pont} ; St_{pont})$$

B. Moving the electricity production from condensing plants, e_{pp} to CHP plants

First the minimum condensing power plant production necessary to fulfil the requirement of stabilising the grid is found:

$$e_{PP\text{-}min} = e_{ia} * S_{stab/tot} - (e_{CHP} + e_{CSHP}) * S_{stab/CHP} - e_w * S_{stab/wind}$$

Then the potential increase in district heating production from CHP, CHP_{pont} and the potential increase in storage content, St_{pont} are determined

$$CHP_{pont} = \min((C_{CHP} – e_{CHP}) ; (e_{PP} – e_{PP\text{-}min}))$$

$$St_{pont} = H_{STORAGE} * 50\% – Q_{STORAGE}$$

New values can now be calculated:

$$e_{CHP\text{-}new} = e_{CHP\text{-}old} + \min(CHP_{pont} ; St_{pont}) * (C_{CHP}/H_{CHP})$$
$$e_{PP\text{-}new} = e_{PP\text{-}old} - \min(CHP_{pont} ; St_{pont}) * (C_{CHP}/H_{CHP})$$
$$q_{CHP\text{-}new} = c_{CHP\text{-}old} + \min(CHP_{pont} ; St_{pont})$$
$$Q_{STORAGE\text{-}new} = Q_{STORAGE\text{-}old} + \min(CHP_{pont} ; St_{pont})$$

C. Reducing the CHP production in situations with electricity export

First, the minimum CHP production necessary to fulfil the requirement of stabilising the grid is found:

$e_{CHP-min} = (e_{ia} * S_{stab/tot} - e_{w} * S_{stab/wind} - e_{PP}) / S_{stab/CHP} - e_{CSHP}$

Secondly, the smallest potential e_{CHP} reduction, CHP_{red} and the storage content, $Q_{STORAGE}$ are found.

$CHP_{red} = \min(e_{x} ; e_{CHP} - e_{CHP-min}) * (H_{CHP}/C_{CHP}) * ((p_{i}<MC_{P}) \text{ or } (e_{x}=e_{cx}))$

The last parenthesis states that the market price, p_i has to be below the marginal production cost of one MWh electricity on the CHP plant, MC_{chp} or the electricity export in question should be critical export, otherwise the CHP_{red} is set to zero.

New values can now be calculated:

$e_{CHP-new} = e_{CHP-old} - \min(CHP_{red} ; Q_{STORAGE}) * (C_{CHP}/H_{CHP})$
$e_{x-new} = e_{x-old} - \min(CHP_{red} ; Q_{STORAGE}) * (C_{HP}/H_{HP})$
$q_{CHP-new} = q_{CHP-old} - \min(CHP_{red} ; Q_{STORAGE})$
$Q_{STORAGE-new} = Q_{STORAGE-old} - \min(CHP_{red} ; Q_{STORAGE})$

D. Reducing boiler production

First, the smallest potential reduction in boiler production, q_{B-red} and potential reduction in storage content, St_{red} are determined:

$q_{B-red} = q_{B}$

$St_{red} = \max(Q_{STORAGE} - H_{STORAGE} * 50\% ; 0)$

New values can now be calculated:

$q_{B-new} = q_{B-old} - \min(q_{B-red} ; St_{red})$
$Q_{STORAGE-new} = Q_{STORAGE-old} - \min(q_{B-red} ; St_{red})$

7. Reducing critical electricity export

The following five means to reduce Critical Electricity Export, e_{cx} have been implemented into the model:

1: Reducing wind power production
2: Reducing CHP production in group 2 (Replacing with boiler)
3: Reducing CHP production in group 3 (Replacing with boiler)
4: Replacing boiler production with electric heating in group 2
5: Replacing boiler production with electric heating in group 3

It is possible to specify one or more numbers, which will be treated in the specified order. (See section 3.4)

Regarding 1: Reducing wind power production

First wind power production in on-shore is reduced. The potential is found as follows:

$$Red_{pont} = \min(e_{w\text{-}onshore} \; ; e_{cx})$$

Now new values are calculated:

$$e_{w\text{-}onshore\text{-}new} = e_{w\text{-}onshore\text{-}old} - Red_{pont}$$
$$e_{cx\text{-}new} = e_{cx\text{-}old} - Red_{pont}$$

Off-shore wind power production is thereafter calculated in the same manner.

Regarding 2: Reducing CHP production in group 2

First, the minimum CHP production necessary to fulfil the requirement of stabilising the grid is found:

$$e_{CHP\text{-}min\text{-}gr\,2} = (e_{ia} * S_{stab/tot} - e_{w} * S_{stab/wind} - e_{PP}) / S_{stab/CHP} - e_{CSHP} - e_{CHP\text{-}gr\,3}$$

Then the potential reduction is found:

$$Red_{pont\text{-}gr2} = \min(e_{chp\text{-}gr2} - e_{CHP\text{-}min\text{-}gr2} \; ; e_{cx})$$

Giving new values:

$$e_{CHP\text{-}gr2\text{-}new} = e_{CHP\text{-}gr2\text{-}old} - Red_{pont\text{-}gr2}$$
$$e_{cx\text{-}new} = e_{cx\text{-}old} - Red_{pont\text{-}gr2}$$
$$q_{CHP\text{-}gr2\text{-}new} = e_{CHP\text{-}gr2\text{-}new} * H_{CHP\text{-}gr2}/C_{CHP\text{-}gr2}$$
$$q_{B\text{-}gr2\text{-}new} = q_{B\text{-}gr2\text{-}old} - Red_{pont\text{-}gr2} * H_{CHP\text{-}gr2}/C_{CHP\text{-}gr2}$$

Regarding 3: Reducing CHP production in group 3

The same calculations as above just replacing group 2 with group 3.

Regarding 4: Replacing boiler production with electric heating in group 2

The potential reduction is calculated as follows:

$Red_{pont-gr2} = min(q_b ; e_{cx})$

Then the value for electric heating is calculated

$E_{electricheating} = Red_{pont-gr2}$

Subsequently, new values for e_{cx} and q_{b-gr3} are calculated.

Regarding 5: Replacing boiler production with electric heating in group 3

The same calculations as situation 4 just replacing group 2 with group 3.

8. Electricity market modelling

The market price at the external electricity market is defined by the following input (see sections 3.4 and 5.3):

- An hour by hour distribution of prices
- A multiplication factor, and
- An addition factor
- A dependency factor (dependency of import/export)

From these inputs the system price is calculated as described in section 5.3.

Based on such hour by hour system prices, the model offers the following three different ways of calculating the pricing of import/export.

The three different market models are chosen by activating the "Market model" button under the "Regulation window" (See section 3.4)

Market model 1: System price

In model 1 the payment for import/export is simply found by multiplying the import/export by the system price.

Market model 2: Export bottleneck

Model 2 introduces a separation in price areas, if *export* reaches the limitation of the transmission capacity. In case of critical surplus production the internal price is set to zero, and in the rest of the situations the internal market price is defined by the short-term marginal costs of the power plant.

Market model 3: Both export and import bottlenecks

In model 3 the bottleneck separation in price areas is introduced for both *export* (equal to model 2) and *import*. Critical surplus production is not relevant for import situations, but in the situations of limitations in the transmission capacity the prices are defined as the system price + 150 DDK/MWh.

9. Fuel and CO_2 accounts

Given a number of inputs the model will make a fuel account and a CO_2 account. Also the model can be activated to calculate all relevant short-term marginal costs and use them to maximise revenues on the external electricity market.

9.1 Fuel account

The fuel account in the model is divided into the following types of fuel:

- Coal
- Oil
- Natural Gas, and Biomass

For each energy unit in the model (DHP, CHP2, CHP3, Boiler2, Boiler 3 and PP) the distribution on fuel types are stated as input (See section 3.5). Additional fuel distributions for external components (transport, households, industry and various) can be described as input as well in order for the model to calculate a complete fuel and CO_2 account for the total energy system of the region.

In the calculation the input fuel consumption for the four external components are simply added to the account. For the rest of the components the distribution is calculated relatively. The total fuel consumption of each energy unit is the result of the system analyses described in sections 6,7 and 8. Given the total fuel consumption, the distribution on the four fuel types is calculated relatively according to the input values.

If for instance:

The total energy consumption for the DHP unit is found to be 10 TWh, and
The input fuel distribution is stated as follows: Coal=1, Oil=1, Ngas=2, Biomass=1
Then the result will be as follows: Coal=2, Oil=2, Ngas=4, Biomass=2, Total=10.

The model can be told to consider limitations in some of the fuel types by activating the "Variable / Fixed" button in input.

If for instance:

the total energy consumption for the DHP unit is found to be 10 TWh, and
the input fuel distribution is stated as follows: Coal=1, Oil=1, Ngas=2, Biomass=1
and the button for biomass is activated as "Fixed"
Then the result will be as follows: Coal=2.25, Oil=2.25, Ngas=4.5, Biomass=1, Total=10.

If all buttons are activated on "fixed", then the model is told to consider them all as "variable".

The model also makes an import/export corrected fuel account: This is done simply by using the input data for the PP unit to adjust the import/export.

In the final account wind power, photo-voltaic and solar thermal are added to the account as a fifth type of fuel named "Renewable"

9.2 CO_2 account

Given the CO_2 emission (kg/GJ) for each of the four fuel types as an input the model calculates the CO_2 emission simply by multiplying the fuel consumption by the emission data.

The model also calculates an import/export corrected CO_2 emission by using the import/export corrected fuel account.

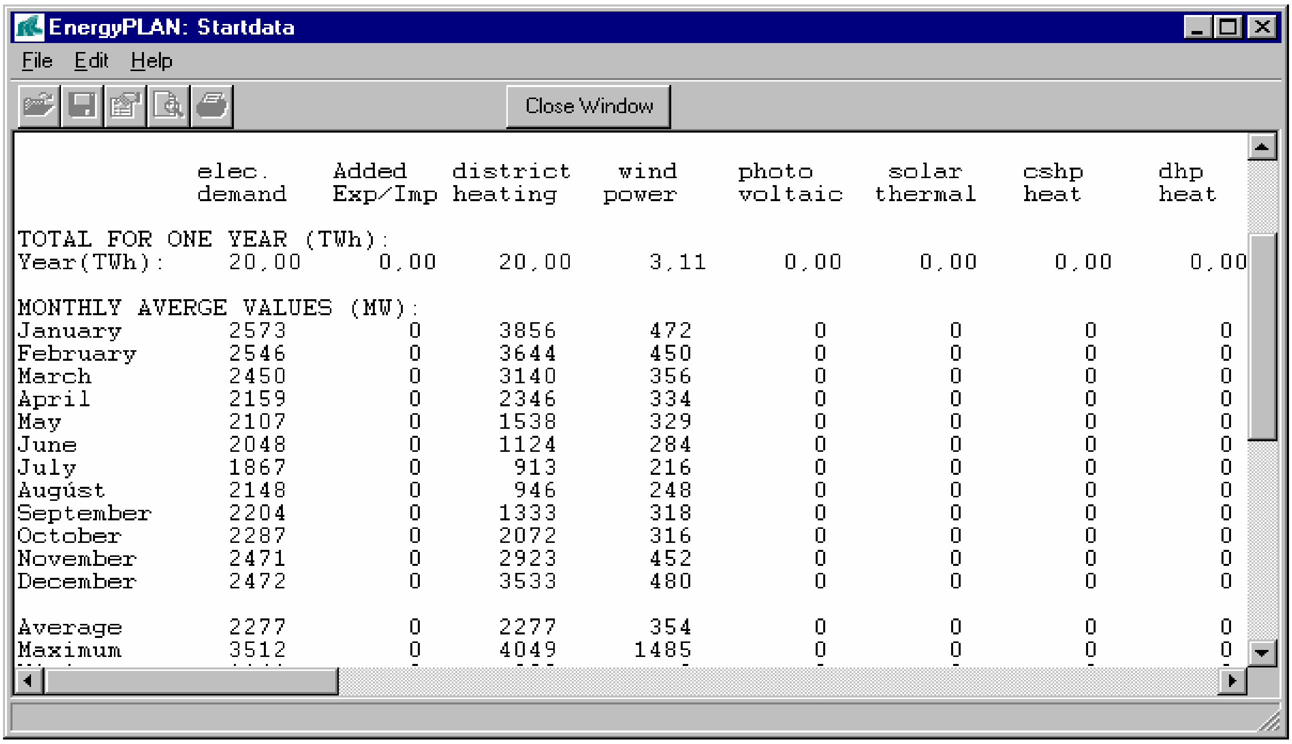
10. Output

The output can be shown and/or exported from the model in the following ways:

- Results can be viewed in a clipboard and exported by the "cut and paste" function
- Results can be printed in an A4 version defined by the model
- Results can be shown graphically and exported by the clipboard function

10.1 The view clipboard function

The function can be activated in the upper line of the main display of the programme in the picture called "view clipboard". When activating this facility the programme will start calculating and then open a text-file, in which the results are shown. (See diagram 13). By using the general cut and paste function in windows the figures can be exported to other programs.



	elec. demand	Added Exp/Imp	district heating	wind power	photo voltaic	solar thermal	cshp heat	dhp heat
TOTAL FOR ONE YEAR (TWh):								
Year(TWh):	20,00	0,00	20,00	3,11	0,00	0,00	0,00	0,00
MONTHLY AVERGE VALUES (MW):								
January	2573	0	3856	472	0	0	0	0
February	2546	0	3644	450	0	0	0	0
March	2450	0	3140	356	0	0	0	0
April	2159	0	2346	334	0	0	0	0
May	2107	0	1538	329	0	0	0	0
June	2048	0	1124	284	0	0	0	0
July	1867	0	913	216	0	0	0	0
August	2148	0	946	248	0	0	0	0
September	2204	0	1333	318	0	0	0	0
October	2287	0	2072	316	0	0	0	0
November	2471	0	2923	452	0	0	0	0
December	2472	0	3533	480	0	0	0	0
Average	2277	0	2277	354	0	0	0	0
Maximum	3512	0	4049	1485	0	0	0	0

Diagram 13: Results can be shown on the screen in the "view clipboard" window

The user can define the results to be shown in the "Setup" window in the EnergyPLAN model. (See diagram 14) All hour by hour data for all the calculations are available.

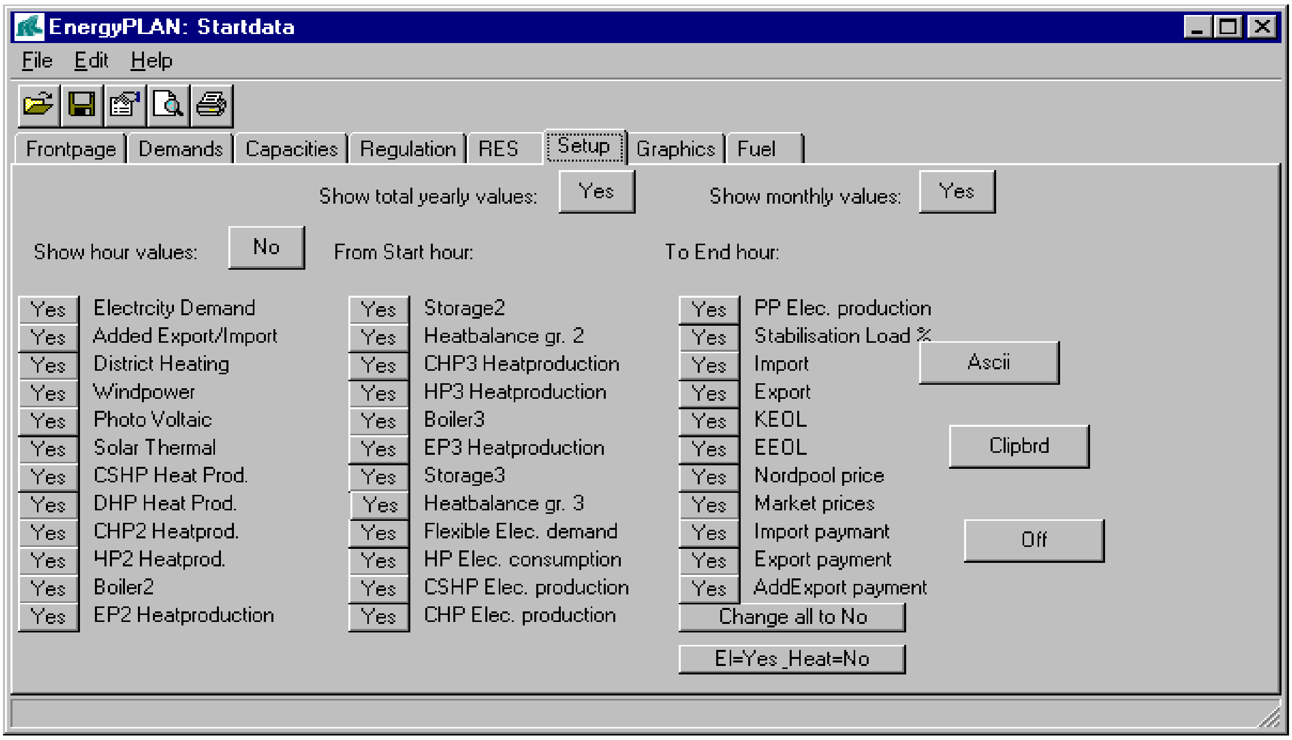


Diagram 14: The "setup" window define which results to be shown in the "view clipboard" window

10.2. The print

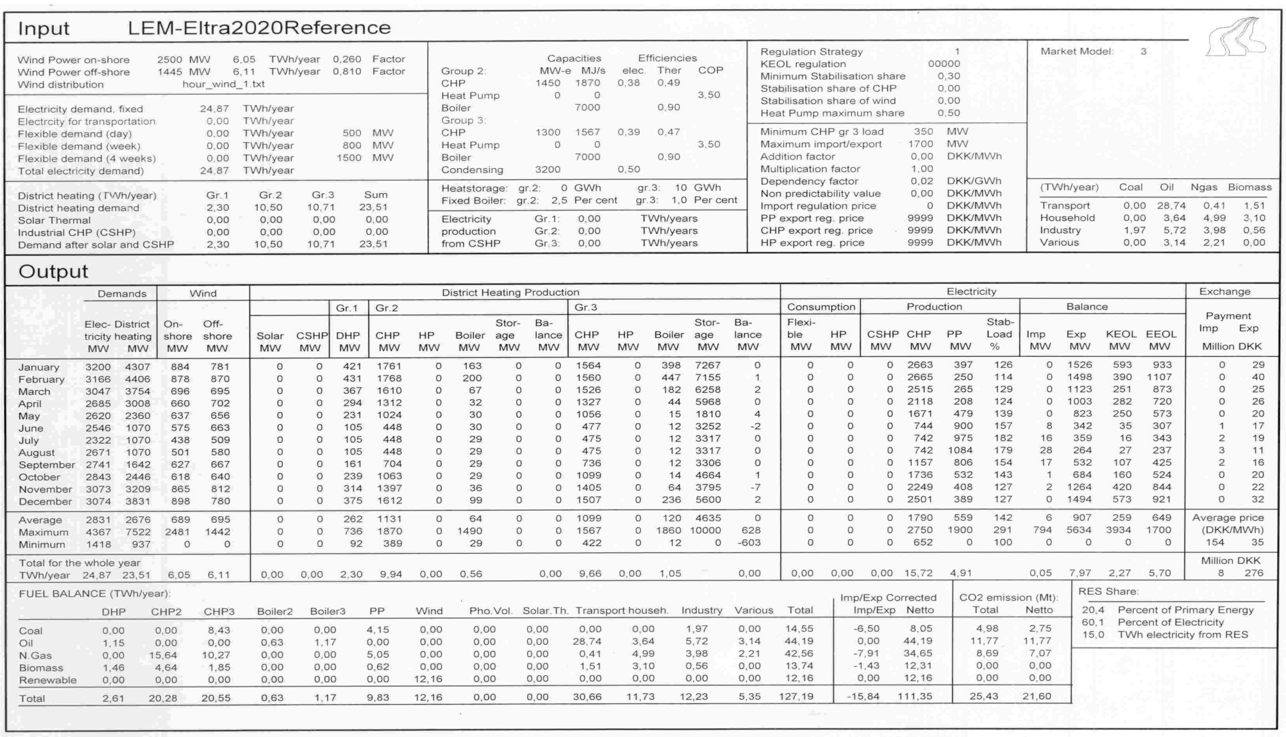
The function can be activated in the upper line of the main display of the programme in the picture called "printer". When activating this facility the programme will start calculating and then send a print to the printer. An example is shown on the next page.

10.3. Graphics

By activating the "Graphics" window the results can be illustrated graphically using the hour by hour values. Three choices are offered by activating the buttons in the lower left corner:

- The model is able to show either the electricity balance, the district heating balance or the flexible electricity demand. Three diagrams are shown for each of the items
- The length of the diagrams can be shown either for one day, three days, one week or one month
- The diagrams can be shown either in colour or in monochrome (black and white)

The results can be shown for all periods of the year by activating the two buttons "Forward" and "Back". Also the diagrams can be exported by activating the "clipboard" button located in the upper right corner of each diagram.



Input LEM-Eltra2020Reference

Wind Power on-shore	2500 MW	6,05	TWh/year	0,260	Factor
Wind Power off-shore	1445 MW	6,11	TWh/year	0,810	Factor
Wind distribution	hour_wind_1.txt				

Electricity demand, fixed	24,87	TWh/year		
Electrcity for transportation	0,00	TWh/year		
Flexible demand (day)	0,00	TWh/year	500	MW
Flexible demand (week)	0,00	TWh/year	800	MW
Flexible demand (4 weeks)	0,00	TWh/year	1500	MW
Total electricity demand)	24,87	TWh/year		

District heating (TWh/year)	Gr.1	Gr.2	Gr.3	Sum
District heating demand	2,30	10,50	10,71	23,51
Solar Thermal	0,00	0,00	0,00	0,00
Industrial CHP (CSHP)	0,00	0,00	0,00	0,00
Demand after solar and CSHP	2,30	10,50	10,71	23,51

	Capacities		Efficiencies		
Group 2:	MW-e	MJ/s	elec.	Ther	COP
CHP	1450	1870	0,38	0,49	
Heat Pump	0	0			3,50
Boiler		7000		0,90	
Group 3:					
CHP	1300	1567	0,39	0,47	
Heat Pump	0	0			3,50
Boiler		7000		0,90	
Condensing	3200		0,50		

Heatstorage: gr.2: 0 GWh gr.3: 10 GWh
Fixed Boiler: gr.2: 2,5 Per cent gr.3: 1,0 Per cent

Electricity	Gr.1:	0,00	TWh/years
production	Gr.2:	0,00	TWh/years
from CSHP	Gr.3:	0,00	TWh/years

Regulation Strategy	1	
KEOL regulation	00000	
Minimum Stabilisation share	0,30	
Stabilisation share of CHP	0,00	
Stabilisation share of wind	0,00	
Heat Pump maximum share	0,50	
Minimum CHP gr 3 load	350	MW
Maximum import/export	1700	MW
Addition factor	0,00	DKK/MWh
Multiplication factor	1,00	
Dependency factor	0,02	DKK/GWh
Non predictability value	0,00	DKK/MWh
Import regulation price	0	DKK/MWh
PP export reg. price	9999	DKK/MWh
CHP export reg. price	9999	DKK/MWh
HP export reg. price	9999	DKK/MWh

Market Model: 3

(TWh/year)	Coal	Oil	Ngas	Biomass
Transport	0,00	28,74	0,41	1,51
Household	0,00	3,64	4,99	3,10
Industry	1,97	5,72	3,98	0,56
Various	0,00	3,14	2,21	0,00

Output

	Demands		Wind		District Heating Production													Electricity										Exchange	
							Gr.1	Gr.2					Gr.3					Consumption		Production				Balance				Payment	
	Electricity MW	District heating MW	On-shore MW	Off-shore MW	Solar MW	CSHP MW	DHP MW	CHP MW	HP MW	Boiler MW	Storage MW	Balance MW	CHP MW	HP MW	Boiler MW	Storage MW	Balance MW	Flexible MW	HP MW	CSHP MW	CHP MW	PP MW	Stab-Load %	Imp MW	Exp MW	KEOL MW	EEOL MW	Imp Million DKK	Exp Million DKK
January	3200	4307	884	781	0	0	421	1761	0	163	0	0	1564	0	398	7267	0	0	0	0	2663	397	126	0	1526	593	933	0	29
February	3166	4406	878	870	0	0	431	1768	0	200	0	0	1560	0	447	7155	1	0	0	0	2665	250	114	0	1498	390	1107	0	40
March	3047	3754	696	695	0	0	367	1610	0	67	0	0	1526	0	182	6258	2	0	0	0	2515	265	129	0	1123	251	873	0	25
April	2685	3008	660	702	0	0	294	1312	0	32	0	0	1327	0	44	5968	0	0	0	0	2118	208	124	0	1003	282	720	0	26
May	2620	2360	637	656	0	0	231	1024	0	30	0	0	1056	0	15	1810	4	0	0	0	1671	479	139	0	823	250	573	0	20
June	2546	1070	575	663	0	0	105	448	0	30	0	0	477	0	12	3252	-2	0	0	0	744	900	157	8	342	35	307	1	17
July	2322	1070	438	509	0	0	105	448	0	29	0	0	475	0	12	3317	0	0	0	0	742	975	182	16	359	16	343	2	19
August	2671	1070	501	580	0	0	105	448	0	29	0	0	475	0	12	3317	0	0	0	0	742	1084	179	28	264	27	237	3	11
September	2741	1642	627	667	0	0	161	704	0	29	0	0	736	0	12	3306	0	0	0	0	1157	806	154	17	532	107	425	2	16
October	2843	2446	618	640	0	0	239	1063	0	29	0	0	1099	0	14	4664	1	0	0	0	1736	532	143	1	684	160	524	0	20
November	3073	3209	865	812	0	0	314	1397	0	36	0	0	1405	0	64	3795	-7	0	0	0	2249	408	127	2	1264	420	844	0	22
December	3074	3831	898	780	0	0	375	1612	0	99	0	0	1507	0	236	5600	2	0	0	0	2501	389	127	0	1494	573	921	0	32
Average	2831	2676	689	695	0	0	262	1131	0	64	0	0	1099	0	120	4635	0	0	0	0	1790	559	142	6	907	259	649	Average price	
Maximum	4367	7522	2481	1442	0	0	736	1870	0	1490	0	0	1567	0	1860	10000	628	0	0	0	2750	1900	291	794	5634	3934	1700	(DKK/MWh)	
Minimum	1418	937	0	0	0	0	92	389	0	29	0	0	422	0	12	0	-603	0	0	0	652	0	100	0	0	0	0	154	35
Total for the whole year TWh/year	24,87	23,51	6,05	6,11	0,00	0,00	2,30	9,94	0,00	0,56		0,00	9,66	0,00	1,05		0,00	0,00	0,00	0,00	15,72	4,91		0,05	7,97	2,27	5,70	Million DKK 8	276

FUEL BALANCE (TWh/year):

	DHP	CHP2	CHP3	Boiler2	Boiler3	PP	Wind	Pho.Vol.	Solar.Th.	Transport	househ.	Industry	Various	Total	Imp/Exp Corrected Imp/Exp	Netto	CO2 emission (Mt): Total	Netto
Coal	0,00	0,00	8,43	0,00	0,00	4,15	0,00	0,00	0,00	0,00	0,00	1,97	0,00	14,55	-6,50	8,05	4,98	2,75
Oil	1,15	0,00	0,00	0,63	1,17	0,00	0,00	0,00	0,00	28,74	3,64	5,72	3,14	44,19	0,00	44,19	11,77	11,77
N.Gas	0,00	15,64	10,27	0,00	0,00	5,05	0,00	0,00	0,00	0,41	4,99	3,98	2,21	42,56	-7,91	34,65	8,69	7,07
Biomass	1,46	4,64	1,85	0,00	0,00	0,62	0,00	0,00	0,00	1,51	3,10	0,56	0,00	13,74	-1,43	12,31	0,00	0,00
Renewable	0,00	0,00	0,00	0,00	0,00	0,00	12,16	0,00	0,00	0,00	0,00	0,00	0,00	12,16	0,00	12,16	0,00	0,00
Total	2,61	20,28	20,55	0,63	1,17	9,83	12,16	0,00	0,00	30,66	11,73	12,23	5,35	127,19	-15,84	111,35	25,43	21,60

RES Share:

20,4	Percent of Primary Energy
60,1	Percent of Electricity
15,0	TWh electricity from RES

Diagram 15: Example of print results

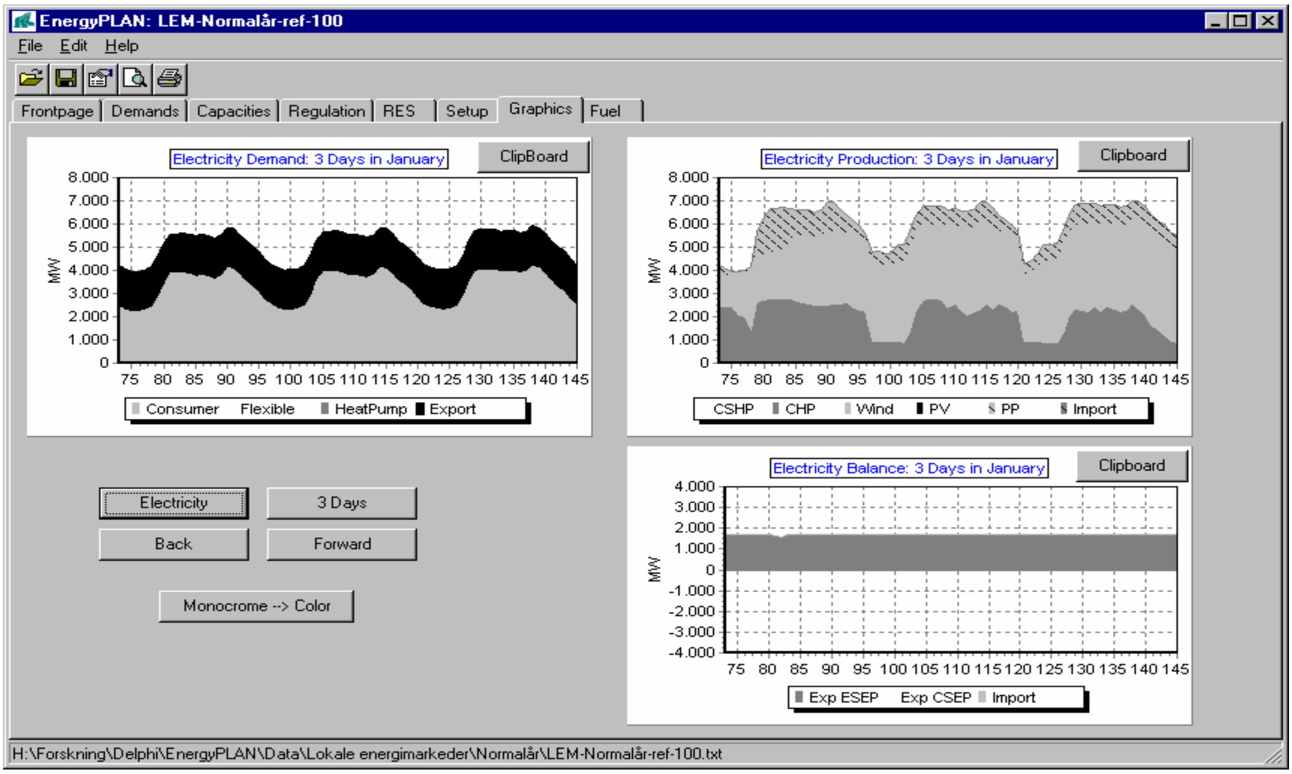


Diagram 16: Example of graphical illustrations of results