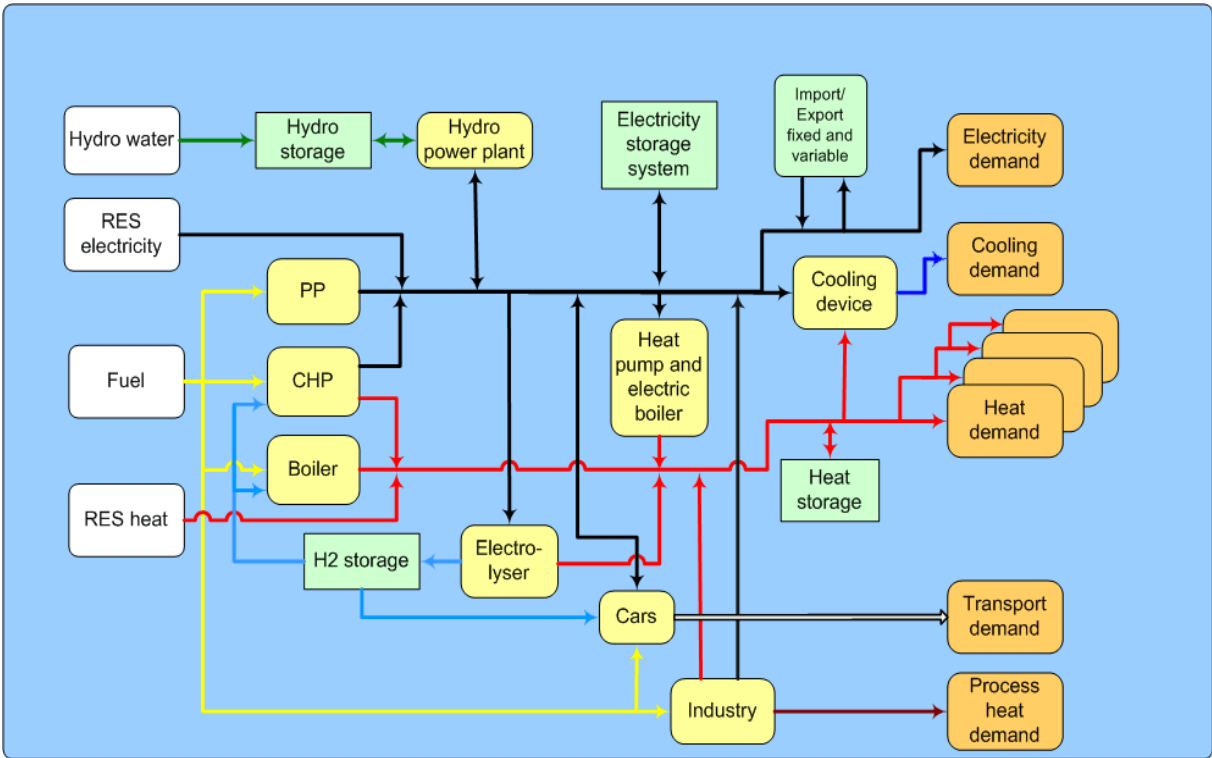




EnergyPLAN

Advanced Energy Systems Analysis Computer Model

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Documentation Version 7.0

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Preface

The EnergyPLAN model has been developed and expanded into the version 7.0 in the period since year 1999.

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, all the hour by hour distribution data were transformed into external text files. Altogether, 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 been expanded into version 6.0. This transformation was implemented by Henrik Lund with the help and assistance of Anders N. Andersen and Henning Mæng (Energy and Environmental Data). In version 6.0, the model was expanded with a possibility of calculating the influence of CO₂ emissions and the share of RES when the electricity supply is seen as a part of the total energy system of a region. Further possibilities of analysing different trade options on the external electricity market were added.

During the spring of 2005, the model was expanded into version 6.2 in a comparative study with the H2RES model with a focus on energy system analysis of renewable islands. The comparative study was done together with Neven Duic and Goran Krajacić from University of Zagreb. As part of the work, two new possibilities of storing/converting electricity storage facilities were added to the EnergyPLAN model. The one is an electricity storage unit, which can be used for modelling e.g. hydro storage or battery storage. The other is electrolyzers which are able to produce fuel (e.g. hydrogen) and heat for district heating. Moreover, the facility of modelling V2Gs (Vehicle to grid) was implemented in corporation with Willet Kempton from University of Delaware.

During the autumn of 2005 and the spring of 2006, the model was expanded further into version 6.6. The main focus was to be able to do modelling of the energy systems of six European countries as part of the EU project DESIRE. Consequently, the possibility of selecting more renewable units, nuclear power and hydro power with water storage and reversible pump facilities was added to the system.

During the summer and autumn of 2006, the model has been expanded further into the present version 7.0. New components such as different transportation options and different individual heating options have been added. A detailed model of Compressed Air Energy Systems (CAES) has been implemented by the help of PhD student Georges Salgi. Different options of waste utilisation have been added and tested by the help of PhD student Marie Münster. However, the primary achievement has been to implement a new economic regulation of the total energy system on the basis of the optimisation of the business-economic marginal production costs of each component in the system. An option to calculate total annual socio-economic costs has also been added. The new options have been tested and applied to an Energy Plan 2030 for Denmark by the help of PhD student Brian Vad Mathiesen.

Diagrams of the expanded energy model have been made and implemented into the user interface with the assistance of Mette Reiche Sørensen, Aalborg University, who has also assisted in the writing of this documentation.

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Nomenclature

Variables are used for demands, productions, efficiencies and similarly for various components such as electricity demands, boiler productions, etc.

The demand and production unit specifications are given as indexes to the demands and productions.

Annual demands and productions are written in capital letters such as Q and E. The hourly value is written in small letters such as q and e using the same alphabetic letters for the same demands. E.g. the capital letter D is used for annual electricity demands and the small letter d is used for hourly values of electricity demands. Such notation is short for the relation that the sum of 8784 hours of d's during a year adds up to the value of capital D:

$$D_E = \sum_{x=1}^{8784} d_E(x)$$

Examples: D_E, d_{FXDAY}, h_{DH2},			
Annual Demands		Hour demands	
D	Annual electricity Demand	d	hour electricity demand
H	Annual Heat demand	h	hour heat demand
F	Annual Fuel demand/consumption	f	hour fuel demand
Index			
E	Electricity demand	M-Coal	Individual Coal boilers
EH	Electricity heating demand	M-Oil	Individual Oil boilers
EC	Electricity cooling demand	M-Ngas	Individual Natural gas boilers
EX	Fixed Exchange electricity demand	M-Bio	Individual Biomass boilers
FXDay	Flexible demand (1 day)	M-H2CHP	Micro Hydrogen CHP
FXWeek	Flexible demand (1 week)	M-NgasCHP	Micro Natural gas CHP
FX4Week	Flexible demand (4 weeks)	M-BioCHP	Micro Biomass CHP
DH1	District Heating group 1	M-HP	Individual Heat Pump
DH2	District Heating group 2	M-EH	Individual Electric heating
DH3	District Heating group 3	T	Transport
Cool	Cooling (electric grid)	BEV	Battery Electric Vehicle
Cool1	Cooling in DH1	V2G	Vehicle to Grid
Cool2	Cooling in DH2	W1	Waste in DH1
Cool3	Cooling in DH3	W2	Waste in DH2
I	Industry	W3	Waste in DH3
V	Various		
CSHP	Industrial Combined Heat and Power		

Examples: C_{CHP2} , e_{HP2} , Q_{B2} , μ_{CHP2} , α_{ELC2} ,			
Annual Productions		Hour productions	
E	Annual electricity production	e	hour electricity production
Q	Annual Heat production	q	hour heat production
F	Annual Fuel demand/consumption	f	hour fuel demand or production
W	Annual Water supply to Hydro	w	hour water supply
		s	hour energy content in storage
Capacities		Efficiencies	
C	Capacity (Electric)	μ	electric (=electric/fuel)
T	Capacity (Thermal)	ρ	thermal (=heat/fuel)
S	Capacity storage (Energy)	ϕ	COP (=heat/elec) for HPs
LOSS	Loss from storage	α	fuel (=fuel/elec) for electrolysers
SHARE	Share of e.g. DH with Solar	ψ	waste to fluid biofuels
FAC	Correction Factor (e.g. RES prod.)	η	waste to solid biofuels
LIMIT	Capacity limit of micro CHP etc.	τ	waste to various (non energy) products
Stab	Grid stabilisation share		
Index		Various factors	
B1	Boiler in DH group 1	Res3	Renewable Energy Source 3
B2	Boiler in DH group 2	Res4	Renewable Energy Source 4
B3	Boiler in DH group 3	Hydro	Hydro power
CHP2	Combined Heat Power in DH gr. 2	HydroPump	Reversible Hydro power
CHP3	Combined Heat Power in DH gr. 3	Nuclear	Nuclear
HP2	Heat Pump in DH group 1	Geo	Geothermal
HP3	Heat Pump in DH group 2	Elc2	Electrolyser in DH group 2
PP	Power plant (Condensing)	Elc3	Electrolyser in DH group 3
Solar1	Solar thermal in DH group 1	ElcT	Electrolyser for transportation
Solar2	Solar thermal in DH group 2	ElcM	Electrolyser for micro CHP
Solar3	Solar thermal in DH group 3	Pump	Electricity storage charging unit
Res1	Renewable Energy Source 1	Turbine	Electricity storage discharge unit
Res2	Renewable Energy Source 2	CAES	Compressed Air Energy Storage

Examples: $P_{Coal-WM}$, $P_{Coal-TaxI}$, $CO2_{Coal}$,			
Annual Demands and prices		Hour demands	
P	Average Annual price	p	hour prices
A	Annual Cost	n	lifetime
CO2	CO2 emissions	i	interest rate
Index			
WM	World Market	TaxIndv	Fuel Taxes for individuals
HCen	Handling Costs to central level	TaxI	Fuel Taxes for industry
HDec	Handling Costs to decentralised	TaxB	Fuel Taxes for Boilers
HIndv	Handling Costs to individual	TaxCHP	Fuel Taxes for CHP
HRoad	Handling Costs to road transport	TaxCAES	Fuel Taxes for CAES storage
HAir	Handling Costs to Air transport	VOC	Variable Operation Costs
Unit	Per unit prices	FOC	Fixed Operation Cost

2. Introduction

The EnergyPLAN model is a computer model for Energy Systems Analysis. The model has been developed and expanded on a continuous basis since 1999. The analysis is carried out in hour by hour steps for one year. And the consequences are analysed on the basis of different technical regulation strategies as well as market-economic optimisation strategies.

2.1 Purpose and application

The main purpose of the model is to assist the design of national energy planning strategies on the basis of technical and economic analyses of the consequences of different national energy systems and investments. The model emphasises the analysis of different regulation strategies with a focus on the interaction between combined heat and power production (CHP) and fluctuating renewable energy sources.

The model is an input/output model. General inputs are demands, renewable energy sources, energy plant capacities, costs and a number of optional different regulation strategies emphasising import/export and excess electricity production. Outputs are energy balances and resulting annual productions, fuel consumption, import/exports and total costs including income from the exchange of electricity.

The model can be used for different kinds of energy system analyses:

Technical analysis

Design and analysis of large and complex energy systems at the national level and under different technical regulation strategies. In this analysis, input is a description of energy demands, production capacities and efficiencies, and energy sources. Output consists of annual energy balances, fuel consumptions and CO₂ emissions.

Market exchange analysis

Further analysis of trade and exchange on international electricity markets. In this case, the model needs further input in order to identify the prices on the market and to determine the response of the market prices to changes in import and export. Input is also needed in order to determine marginal production costs of the individual electricity production units. The modelling is based on the fundamental assumption that each plant optimises according to business-economic profits, including any taxes and CO₂ emissions costs.

Feasibility Studies

Calculation of feasibility in terms of total annual costs of the system under different designs and regulation strategies. In such case, inputs such as investment costs and fixed operation and maintenance costs have to be added together with life time periods and an interest rate. The model determines the socio-economic consequences of the productions. The costs are divided into 1) fuel costs, 2) variable operation costs, 3) investment costs, 4) fixed operation costs, 5) electricity exchange costs and benefits, and 5) possible CO₂ payments.

The principle of the energy system of the EnergyPLAN model is shown in the diagram on the front page. Basically, the input of the energy system consists of the following:

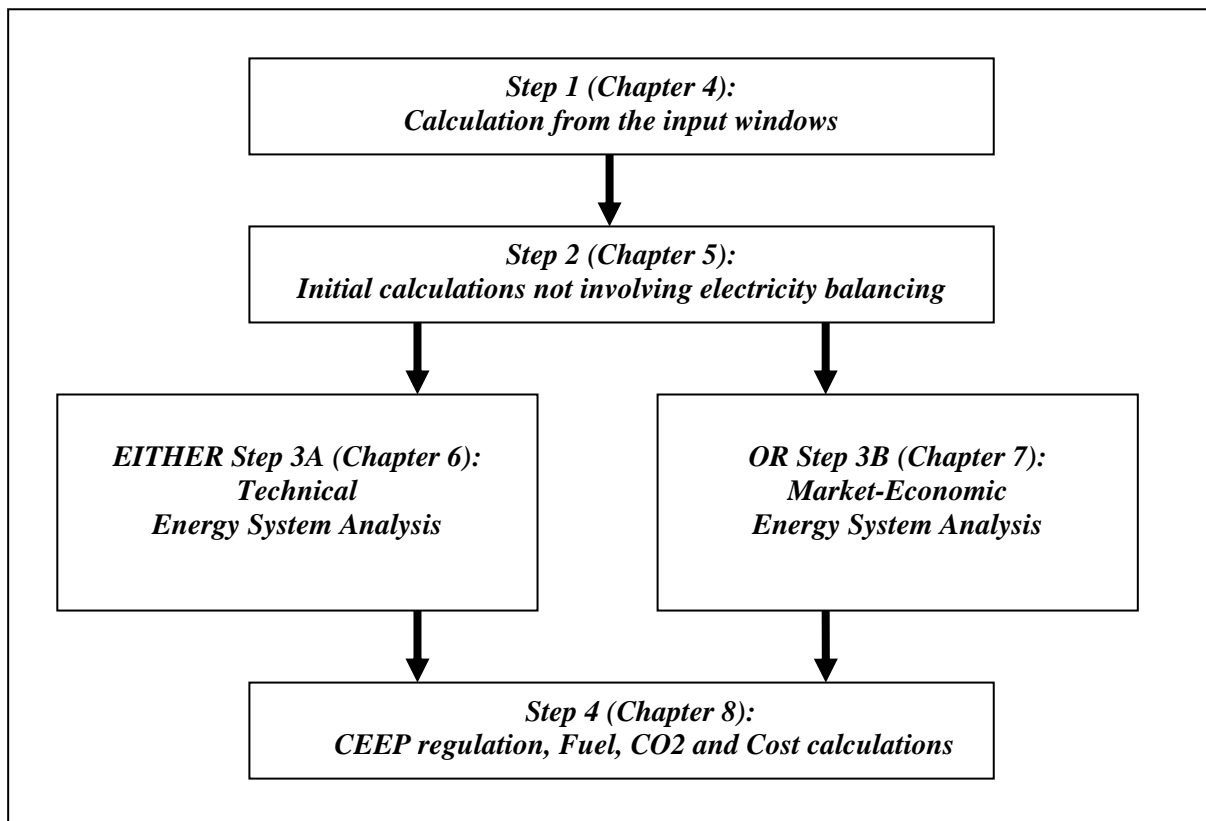
- Energy demands (heat, electricity, transportation etc.)
- Energy production units and resources (wind turbines, power plants, oil boilers, storage etc.)
- Regulation (defining the regulation and operation of each plant and the system including technical limitations such as transmission capacity etc.)

- Costs (Fuel costs, taxes, variable and fixed operation costs and investment costs)

Basically, the model distinguishes between technical regulation and market-economic regulation. In the following, a list of energy demands is presented as well as an overview of all components in the model together with a short description on how they are operated in the two different regulation strategies. Also the main inputs for each component are listed.

2.2 Energy Systems Analysis in the EnergyPLAN model

The procedure of the energy system analysis is shown in the diagram. The calculations are based on the small calculation described in the previous section, which is made simultaneously with the typing of input data in the input and cost windows. Next step consists of some initial calculations, which do not involve electricity balancing. Then the procedure is divided into EITHER a technical OR a market-economic optimisation. The technical optimisation minimises the import/export of electricity and seeks to identify the least fuel-consuming solution. On the other hand, the market-economic optimisation identifies the lowest cost solution on the basis of the business-economic costs of each production unit.



Step 1: Calculation from the input windows:

1. Electricity demand is calculated as in input window section 4.1.1
2. Solar thermal as in section 4.2.1
3. RES1, ... RES4 as in section 4.3.1
4. Hydro Power input as in section 4.3.2
5. Nuclear Power or Geothermal as in section 4.3.3

6. Individual solar thermal, boilers, CHPs and heat pumps are calculated as in section 4.6. (If electrolysers for hydrogen productions are not specified, then the model will identify a minimum capacity and define an electrolyser)
7. Biofuels for transportation and CHP/Boilers produced on waste as in section 4.9.1.
8. Market prices of external market as in section 4.13.

Step 2: Initial calculations not involving electricity balancing

1. Fixed import/export of electricity specified in the Electricity demand window (section 5.1).
2. District heating demands incl. heating demands from absorption cooling (section 5.2).
3. Industrial and Waste district heating and electricity productions (section 5.3).
4. Fixed Boiler production subtracted from the district heating demand (section 5.4).
5. Boiler production in district heating group 1 (section 5.5).

EITHER Step 3A: Technical Energy System Analysis

1. CHP, Heat Pumps and boilers in groups 2 and 3 (regulation 1 or 4) (section 6.2).
2. Flexible electricity demand (including dump charge BEV) (section 6.3).
3. CHP, Heat Pumps and boilers in groups 2 and 3 (regulation 2 or 3) ***If chosen*** (overrules production of regulation 1 or 4) (section 6.4).
4. Hydro power (section 6.5).
5. Individual CHP and Heat Pump systems (section 6.6).
6. Electrolyser for micro CHP, Transportation, DH group 3 and DH group 2 (section 6.7).
7. Heat storage in groups 3 and 2 (section 6.8).
8. Transportation (Smart charge and V2G) (section 6.9).
9. Electricity storage (section 6.10).

The calculation of condensing power and import/export including CEEP and EEEP (Critical and Exportable Excess Electricity production) are calculated continuously more or less after each of the sequences in the technical energy system analysis procedure (section 6.1).

OR Step 3B: Market-Economic Energy System Analysis

1. Market economic optimisation
2. CHP3 minimum production
3. Hydrogen and electricity demands for transportation and micro CHP

Step 4: CEEP regulation, Fuel, CO2 and Cost calculations

1. Fixed boiler production is added to the boilers in groups 2 and 3
2. Critical Excess Regulation
3. Grid stabilisation
4. Heat balances in district heating systems
5. Fuel consumptions
6. CO2 emissions
7. Cost

2.3 Energy Demands

Energy demands include the following:

Electricity demand divided into

1. Fixed demand
2. Three types of flexible demands, and
3. Fixed import/export if any.

District heating demand divided into

2. District heating demand in systems without CHP (Boiler systems),
3. District heating demand in decentralised CHP systems and
4. District heating demand in centralised CHP systems (Typically extraction plants or similar).

Cooling demand divided into:

1. Cooling based on electricity supply (air conditioning etc.)
2. Cooling based on heat supply from district heating from the three DH groups mentioned above (based on absorption technologies)

Heat demand in individual houses divided into

1. Coal, Oil, Natural gas and biomass boilers
2. Micro CHP on either hydrogen, natural gas or biomass
3. Electric heating or heat pumps

Industry divided into Coal, Oil, Natural gas and Biomass

Various divided into Coal, Oil, Natural gas and Biomass

Transportation divided into

1. Jet fuel, Diesel, Petrol, Natural gas and Biomass
2. Biofuels and Hydrogen (produced by other components in the system)
3. Electric transportation including smart charge and V2Gs (Vehicle to Grid)

Industry, Various and Transportation (except from electric transportation) are defined by an annual demand, while all other demands are defined by both an annual demand (TWh per year) and an hour by hour distribution data set (name of data set from the data bank).

2.4 Overview: Components and Regulation

Renewable Energy Sources

Component	Input	Technical regulation	Market-economic regulation
Wind power Offshore wind Photovoltaic Wave power River Hydro	Electric capacity and Hourly distribution	Are given priority in the electricity production	Are given priority in the electricity production. Marginal production costs are defined as zero.
Hydro power	Electric capacity Efficiency Storage capacity Annual Water supply Hourly distribution of water Variable operation costs	First, best possible utilisation of all water input given limitations in capacities is calculated and used as input. Afterwards Hydro power is relocated in the best possible way to avoid excess electricity production.	Identify highest possible production given water input and distribution, turbine capacity and water storage capacity. Sell such maximum production at the highest possible market prices to achieve the highest possible income.
Reversible Hydro Power	<i>Same input as Hydro plus</i> Pump Capacity Pump Efficiency Pump variable opr. Costs	<i>Same as Hydropower plus</i> In the end, the Pump is used in order to avoid excess electricity production and the Turbine to avoid production on condensing power plants.	<i>Same as Hydro power plus</i> The hydro power pump and turbine are used to optimise the profit of the plant based on marginal costs and losses in the energy conversion
Geothermal Power	Electric capacity Efficiency Hourly distribution Variable operation costs	Is given priority in the electricity production.	Produce whenever the electricity price is higher than the variable operation costs.
Solar thermal in district heating system	<i>For each three DH groups:</i> Annual production Hourly distribution Heat storage capacity Losses in heat storage	Is given priority in the district heating supply.	Is given priority in the heat production. Marginal production costs are defined as zero.
Solar thermal in individual houses	<i>For each nine groups:</i> Annual production Hourly distribution Heat storage capacity	Is given priority in the heat supply.	Is given priority in the heat production. Marginal production costs are defined as zero.

Waste utilisation and conversion and industrial electricity and heat production for district heating

Component	Input	Technical regulation	Market-economic regulation
Industrial CHP	Annual production and Hourly distribution	Is given priority in the electricity production	Is given priority in the electricity production. Marginal production costs are defined as zero.
Industrial waste heat for district heating	<i>For each three DH groups:</i> Annual production and Hourly distribution	Is given priority in the district heating supply secondary to solar thermal.	Is given priority in the heat production secondary to solar thermal. Marginal production costs are defined as zero.
Waste incineration	<i>For each three DH groups:</i> Annual waste input and Hourly distribution Plant efficiency (thermal)	Is given priority in the district heating supply secondary to solar thermal.	Is given priority in the heat production secondary to solar thermal. Marginal production costs are defined as zero.

Waste CHP production	<i>For each three DH groups:</i> Annual waste input and Hourly distribution Plant efficiency (thermal) Plant efficiency (electric)	Electricity production is given priority in the supply Heat production is given priority in the district heating supply secondary to solar thermal.	Is given priority in both electricity and heat production secondary to solar thermal. Marginal production costs are defined as zero.
Waste for biofuel for CHP and boilers	<i>For each three DH groups:</i> Annual waste input and Hourly distribution Plant efficiency (biofuel)	Biofuel is utilised to replace fuel in relevant CHP units and boilers.	Biofuel is utilised to replace fuel in relevant CHP units and boilers.
Waste for biofuels for transportation	<i>For each three DH groups:</i> Annual waste input and Hourly distribution Plant efficiency (biofuel)	Biofuel is transferred as input to the transportation window.	Biofuel is transferred as input to the transportation window.

Nuclear power

Component	Input	Technical regulation	Market-economic regulation
Nuclear Power	Electric capacity Efficiency Hourly distribution Variable operation costs	Is given priority in the electricity production.	Produce whenever the electricity price is higher than the variable operation costs.

Power plants, CHP units, heat pumps, electrolysers, heat storage and boilers for DH production

Component	Input	Technical regulation	Market-economic regulation
Boilers	<i>For each three DH groups:</i> Thermal capacity Thermal efficiency Variable operation costs Fuel specification	Are given last priority. If district heating can not be supplied from any other unit (Solar thermal, industrial waste heat, CHP, heat pump or heat storage) then the boiler is used.	The marginal operational cost including fuel costs and taxes is compared to relevant options (such as CHP, heat pump and heat storage) and the business-economically lowest cost solution is selected.
CHP units	<i>For DH groups 2 and 3:</i> Electric capacity Thermal efficiency Electric efficiency Variable operation costs Fuel specification	<i>Technical regulations 1 (and 4)</i> Are given priority after solar thermal and industrial waste heat to cover the heat demand. <i>Technical regulations 2 (and 3)</i> Are given priority after solar thermal and industrial waste heat to cover the heat demand only when electricity production is needed.	The marginal operational cost including fuel costs and taxes is compared to relevant options (such as boiler, heat pump, electrolysers and heat storage) and the business-economically lowest cost solution is selected.
Heat Pumps	<i>For DH groups 2 and 3:</i> Electric capacity COP (Co-efficiency of performance.) Variable operation costs	<i>Technical regulations 1 (and 4)</i> Are given priority after CHP units to cover the heat demand. <i>Technical regulations 2 (and 3)</i> Are used in combination with CHP units to cover the heat demand and balance electricity supply and demand.	The marginal operational cost including fuel costs and taxes is compared to relevant options (such as boiler, CHP, electrolysers and heat storage) and the business-economically lowest cost solution is selected.

Heat Storage	<i>For DH groups 2 and 3:</i> Heat storage capacity	Identify and implement changes in the use of CHP and heat pumps which can decrease excess electricity production and production on condensing power plants, and decrease heat production on boilers.	The heat storage is used in order to implement changes in CHP, heat pump and boilers, which will lead to better business-economic profits.
Electric boiler	No inputs	Only used as part of Critical Excess Electricity regulation if specified in the regulations strategy	Only used as part of Critical Excess Electricity regulation if specified in the regulations strategy
Electrolysers	<i>For DH groups 2 and 3:</i> Electric capacity Efficiency (fuel/hydrogen) Efficiency (heat) Variable operation costs	Are activated in the case of excess electricity production to produce fuel for the CHP and boilers. When activated the electrolysers replace heat production from CHP and heat pumps.	The marginal operational cost including fuel costs and taxes is compared to relevant options (such as boiler, CHP, heat pumps and heat storage) and the business-economically lowest cost solution is selected.
Power plants	Electric capacity Efficiency (electric) Variable operation costs Minimum capacity Fuel specification	Are given priority after all other electricity production units if the demand is still higher than the supply. (Or if production is requested for reasons of grid stability).	Produce whenever the electricity price is higher than the variable operation costs.

Individual house heating and micro CHP

Component	Input	Technical regulation	Market-economic regulation
Coal boilers Oil boilers Ngas boilers Biomass boilers	Efficiency Hour distribution (Fuel consumption is defined as demand)	Are given priority after solar thermal.	Are given priority after solar thermal.
H2 micro CHP Ngas micro CHP Biomass micro CHP	Heat demand Hour distribution capacity (in % of max heat) (Reserve boiler with boiler efficiency of natural gas or biomass boilers is assumed) Thermal efficiency Electric efficiency Variable operation costs of both CHP and boilers Heat storage capacity	Is given priority after solar thermal and before boiler. Heat storage (if any) is used first in order to utilise solar thermal and secondly to relocate CHP production with the aim of decreasing excess electricity production and the quantity of condensing power in the overall system.	The marginal cost including fuel costs and taxes of electricity production on CHP is compared to boiler only production. CHP is activated if the marginal cost is below the market price. Heat storage is used in order to achieve best market prices of electricity produced on CHP.
Heat Pumps in individual houses	Heat demand Hour distribution capacity (in % of max heat) (Reserve electric boiler is assumed) COP Variable operation costs of both heat pump and electric heating Heat storage	Are given priority after solar thermal and before electric boiler. Heat storage (if any) is used first in order to utilise solar thermal and secondly to relocate heat pump consumption with the aim of decreasing excess electricity production and the quantity of condensing power in the overall system.	The marginal cost of producing heat on heat pumps including taxes is compared to electric heating and the lowest cost option is chosen. Heat storage is used in order to achieve lowest market prices of the electricity consumed by heat pumps.

Electric heating in individual houses	Heat demand Hour distribution Heat storage	Is given priority after solar thermal. Heat storage (if any) is used first in order to utilise solar thermal and secondly to relocate electric heating consumption with the aim of decreasing excess electricity production and the quantity of condensing power in the overall system.	Heat storage is used in order to achieve lowest market prices of the electricity consumed by heat pumps.
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Transportation

Component	Input	Technical regulation	Market-economic regulation
Airplanes on JP	Are defined as fuel demands.	None	None
Vehicles on petrol Vehicles on diesel Vehicles on Ngas Vehicles on biofuels	Are defined as fuel demands.	None	None
Vehicles on biofuels from waste conversion	None (Are defined as fuel output from conversion of waste)	None	None
Vehicles on Hydrogen	Hydrogen fuel demand and Hourly distribution (additional input data for electrolyzers are needed, see below)	None (However, the electrolyser is subject to regulation)	None (However, the electrolyser is subject to regulation)
BEV (Battery Electric Vehicle). Dump charge	Electricity demand and Hourly distribution	None (Is included as a fixed electricity demand defined by the hourly distribution.	None (Is included as a fixed electricity demand defined by the hourly distribution.
BEV (Battery Electric Vehicle). Smart charge	Electricity demand and Hour distribution of demand Max share of parked cars Share of cars connected Efficiency of charge Battery capacity Capacity of grid to battery	Electricity charging is used with the aim of decreasing excess electricity production and the quantity of condensing power in the overall system.	Battery storage is used in order to achieve lowest market prices of the electricity consumed.
V2G (Vehicle to grid).	<i>Same as BEV smart plus</i> Efficiency of discharge Capacity of battery to grid	Electricity charging and discharging is used with the aim of decreasing excess electricity production and the quantity of condensing power in the overall system.	Battery storage is used in order to achieve lowest market prices of the electricity consumed and to optimise profits from selling and buying electricity.

Electrolysers and electricity storage systems

Component	Input	Technical regulation	Market-economic regulation
Electrolysers for hydrogen for transportation	Capacity (electric) Efficiency Storage capacity (Demand is defined by hydrogen vehicles)	Hydrogen production is determined by hydrogen demand for transportation. Hydrogen storage is used in order to relocate electricity consumption with the aim of decreasing excess electricity production and the quantity of condensing power in the overall system.	Hydrogen production is determined by hydrogen demand for transportation. Hydrogen storage is used in order to achieve lowest market prices of the electricity consumed by electrolysers.
Electrolysers for hydrogen for micro CHP	Capacity (electric) Efficiency Storage capacity (Demand is defined by hydrogen micro CHP)	Hydrogen production is determined by hydrogen demand for micro CHP. Hydrogen storage is used in order to relocate electricity consumption with the aim of decreasing excess electricity production and the quantity of condensing power in the overall system.	Hydrogen production is determined by hydrogen demand for micro CHP. Hydrogen storage is used in order to achieve lowest market prices of the electricity consumed by electrolysers.
Battery storage Hydro pump storage Hydrogen FC storage	Capacity (charge) Efficiency (charge) Capacity (discharge) Efficiency (discharge) Variable operation costs of both charge and discharge	Charge in case of excess electricity production Discharge in case of condensing power production. Make sure that the storage content is the same at the beginning and at the end of the year.	The charging and discharging is used in order to optimise the profit of the plant based on marginal costs and losses in the energy conversion
CAES (Compressed Air Energy Storage)	<i>Same as battery storage plus</i> Fuel-ratio (defined as fuel input / electric output)	Load in case of excess electricity production Unload in case of condensing power production. Make sure that the storage content is the same at the beginning and at the end of the year.	Optimise the profit of the plant based on marginal costs and losses in the energy conversion

3. Libraries and settings

The model is organised as an executable file and two libraries: Data and Distributions.

Navn	Størrelse	Type
Data		Filmappe
Distributions		Filmappe
energyPLAN.exe	2.124 KB	Program

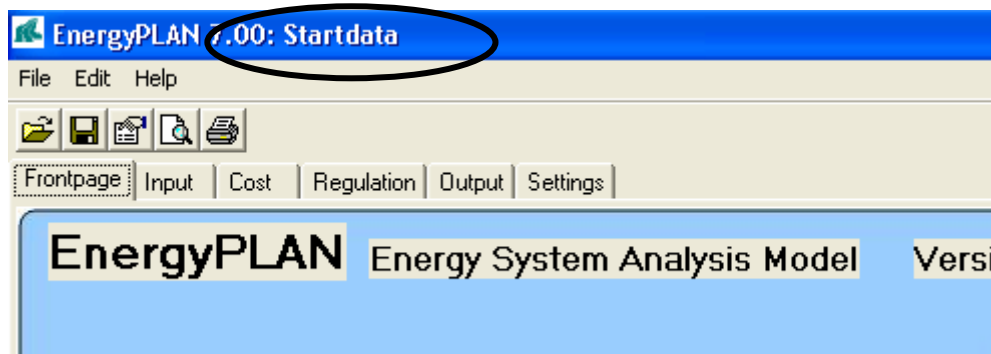
The Data Library holds input data set and the Distribution Library contains hour distributions files. A new Cost Library is planned to include data sets of investment and fuel costs.

3.1 Input data set


The EnergyPLAN model always holds sufficient input data for doing a calculation. Moreover, the model controls if new input data meets the standards. If not they will be rejected.

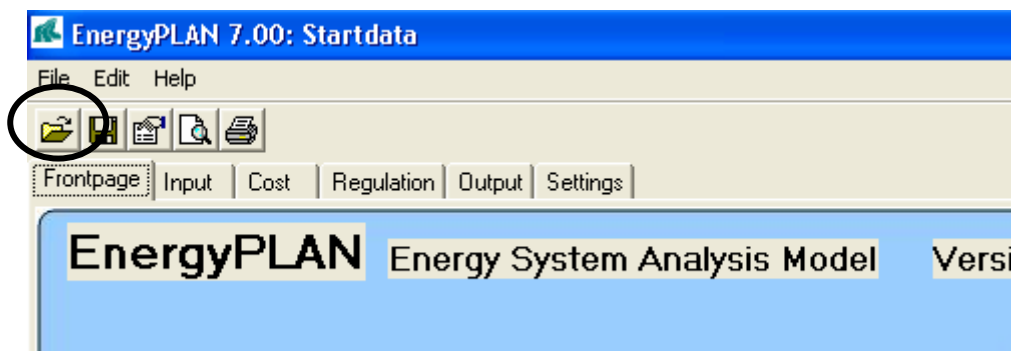
When the program is started the model automatically defines a set of input data, called “Startdata”.

The input data set can be saved and stored in the Data Library. Stored data sets can be read into the model. In the upper left corner, the model shows the name of the present data set (see below).

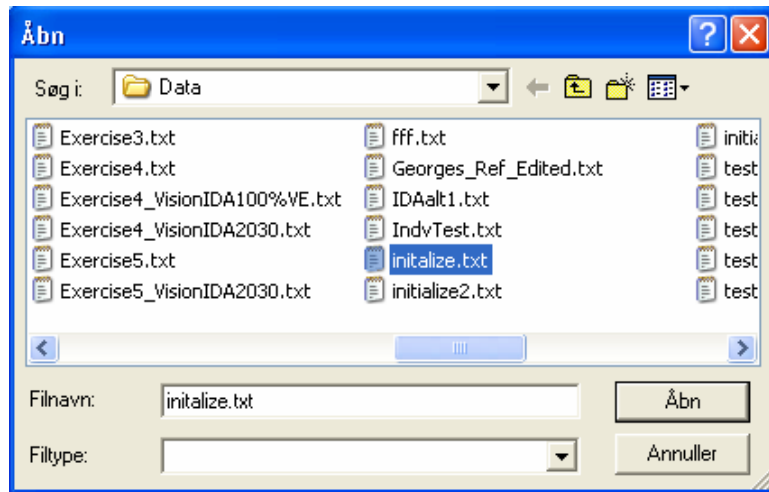


3.1.1 Open an input data set from the Library

To open an input data set from the Library, activate the open button  in the upper left corner.

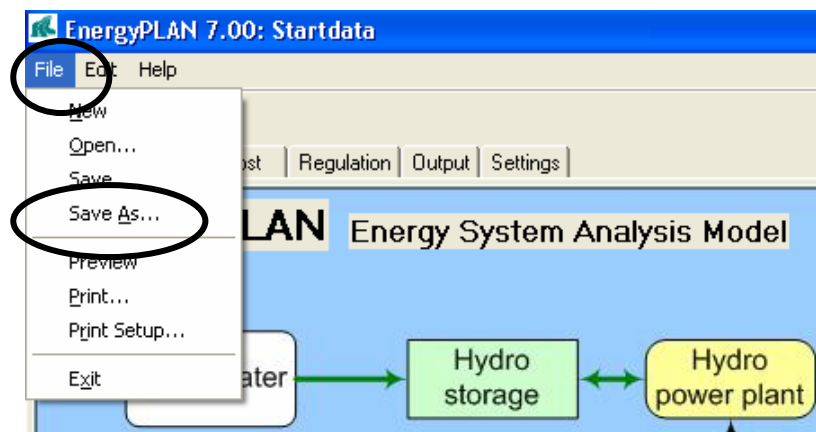


The following window will open, in which one can choose between stored input data sets:

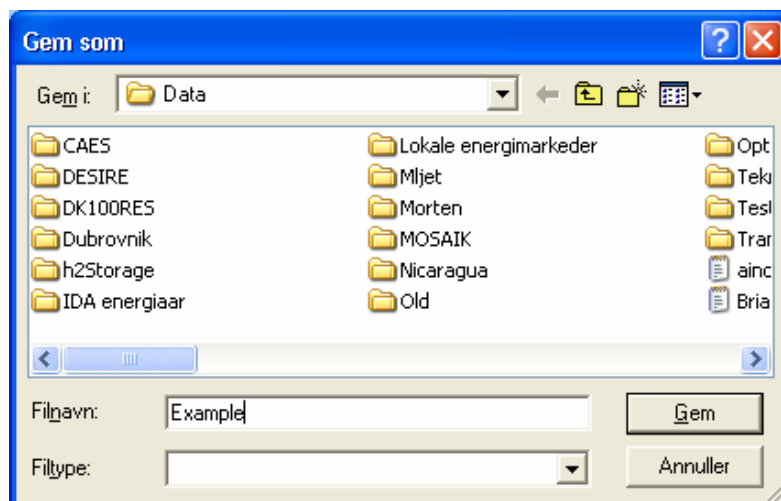


3.1.2 Defining a new input data set and storing it in the Library

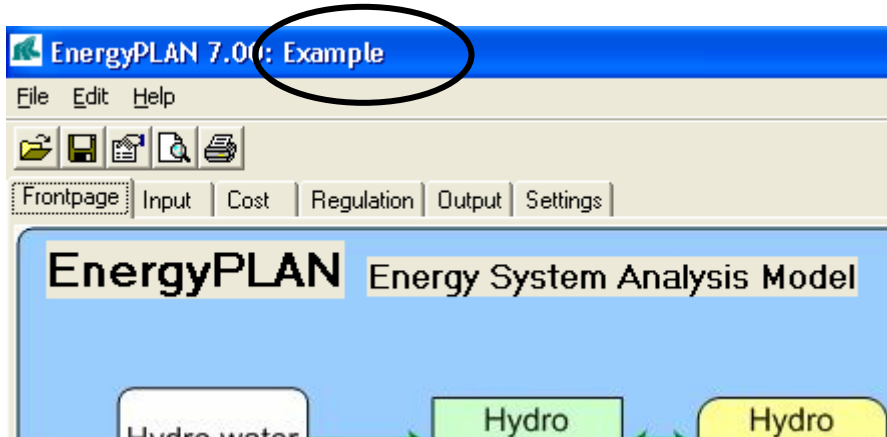
To define a new input data name and save present input data in the Library, activate the file button in the upper left corner and choose “Save As”:




The following window will open, in which one can define the name of the data set, e.g. “Example”:

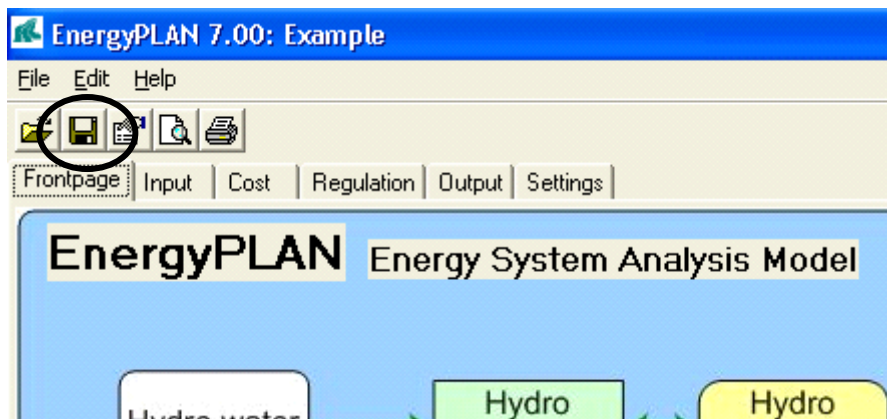


After storing the data set, the new name will appear in the upper left corner:




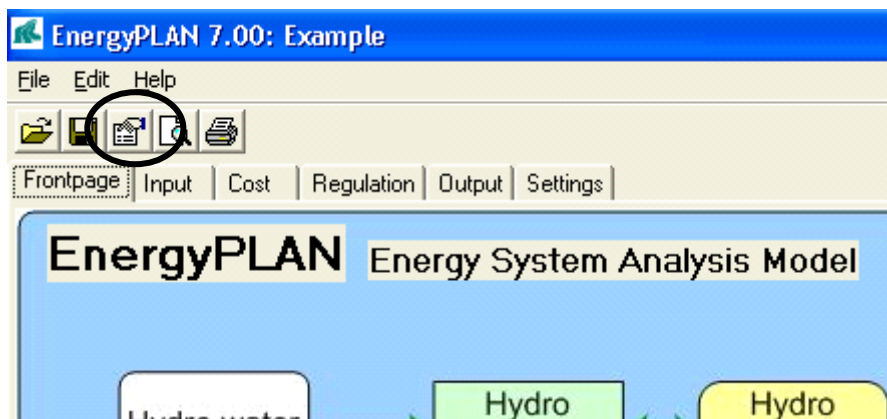
3.1.3 Saving the present input data set in the Library

To save the present input data set (replace present data under the same name) activate the  button in the upper left corner.



3.1.4 Look at the present input data file

The input data sets are stored as text files. One can look at the text file of the present data set by activating the  button in the upper left corner.



3.2 Distribution

Typically, energy demands and renewable resources etc. are defined in the model by an annual value and a distribution name from the Distribution Library.

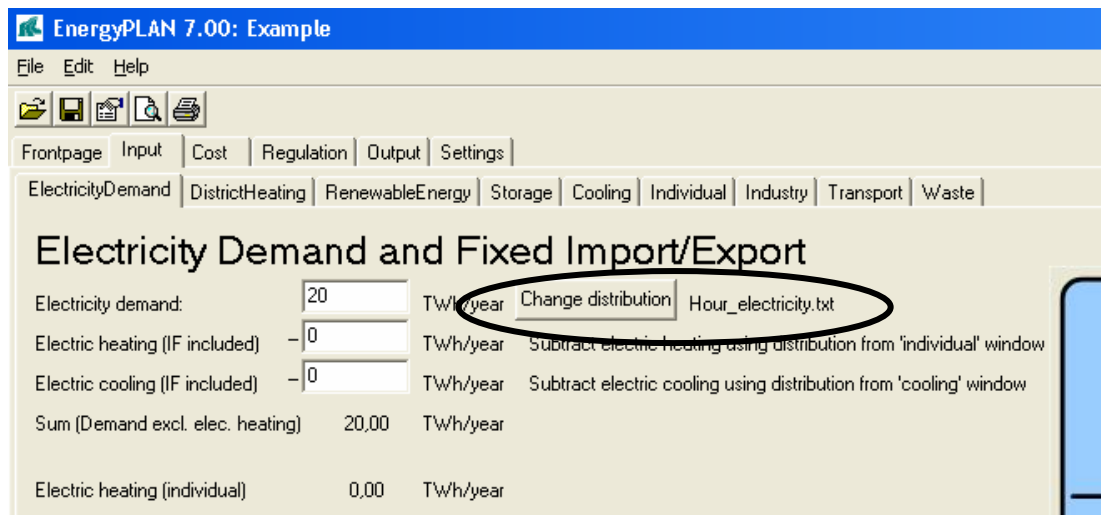
Distributions in the Library are stored as text files and consist of 8784 hour values presented on 8784 lines. New distributions have to meet this format.

For price distributions, the 8784 numbers are absolute. For demands, all values are relative and will relate to the specified annual value. For renewable energy sources, distribution is relative to the specified capacities.

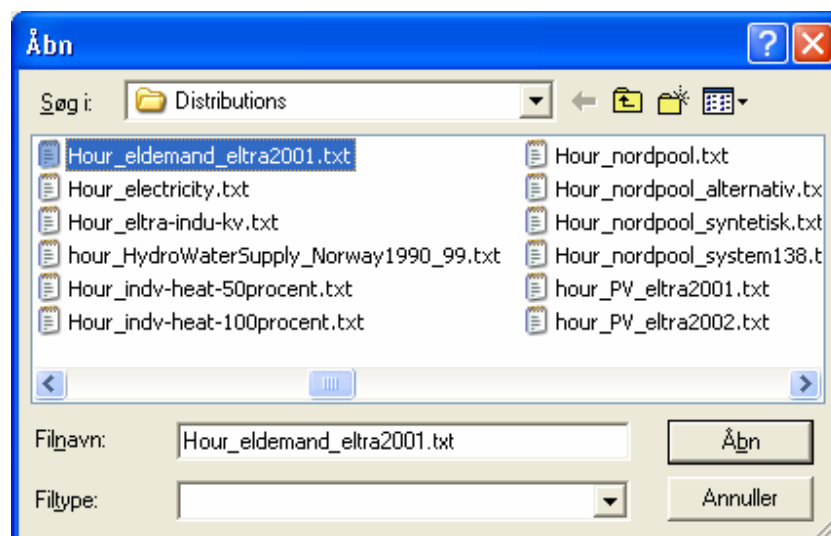
Distributions are defined by their name, and such names are part of the input data set. When the model is started, names are defined for all distributions. However, one can easily change from one distribution to another in the Library.

3.2.1 Change distribution

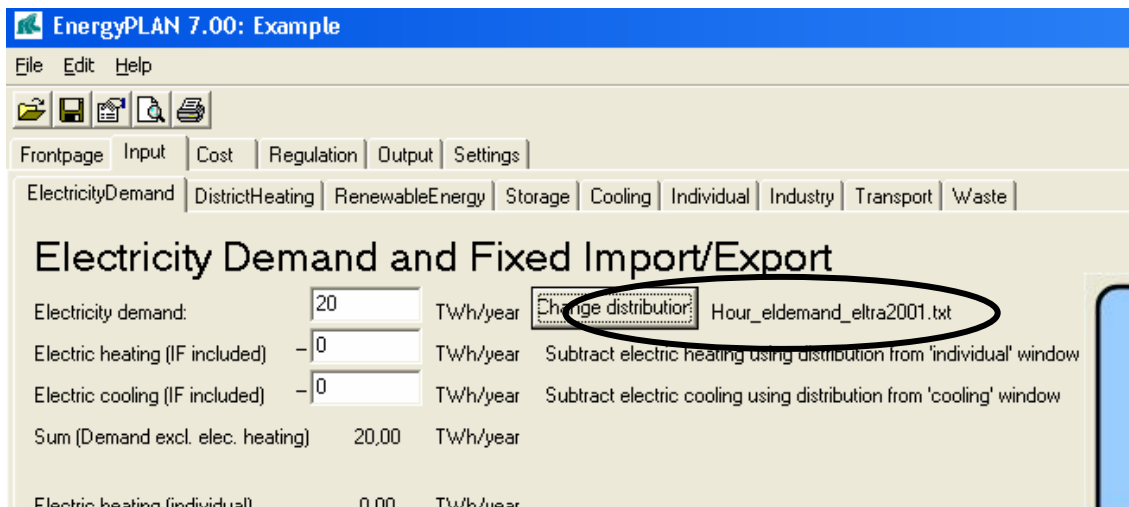
The model shows the name of the present distribution. Here illustrated by the electricity demand:



To change distribution, simply activate the **Change distribution** button and the following window will open:



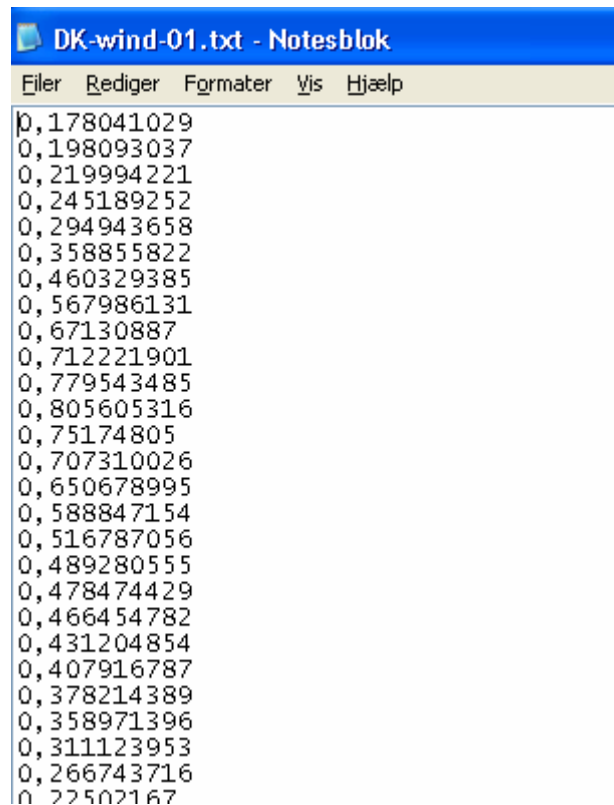
Here one can choose a new distribution, which will then be shown in the input window:



3.2.2 Define new distributions

New distribution data can be added to the Library, simply by producing a text file with 8784 numbers. Distributions in the Library are stored as text files and consist of 8784 hourly values presented on 8784 lines. New distributions have to meet this format.

One fast way of making a new distribution is to open an existing file in the Distribution Library by using the pathfinder. Then, change the data and save under a new name. One can mark all data and load the data into e.g. Excel and change them. Or one can simply replace them with a new set of data.



3.2.3 Existing data in the Library

The model Library already includes a long list of distribution data, among others: Typical Danish electricity demand (year 2000), typical Danish district heating demand, distribution of photovoltaic and solar thermal power, distribution of industrial CHP, different wind years: 1996, 2000 and 2001, and distribution of Nord Pool prices between the different years from 2000 to 2006. Four of the “hour by hour” distribution data sets are illustrated in the diagram below.

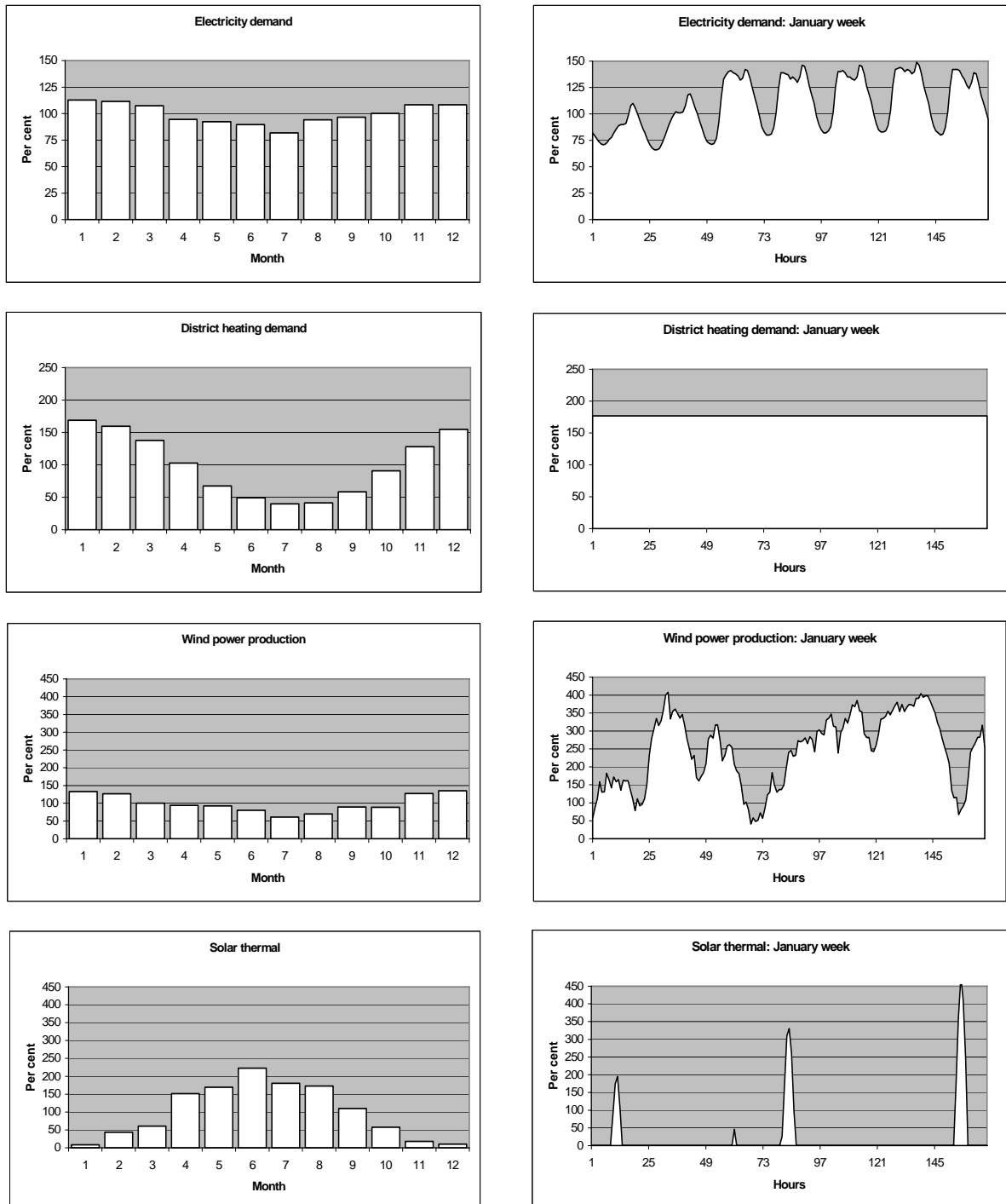
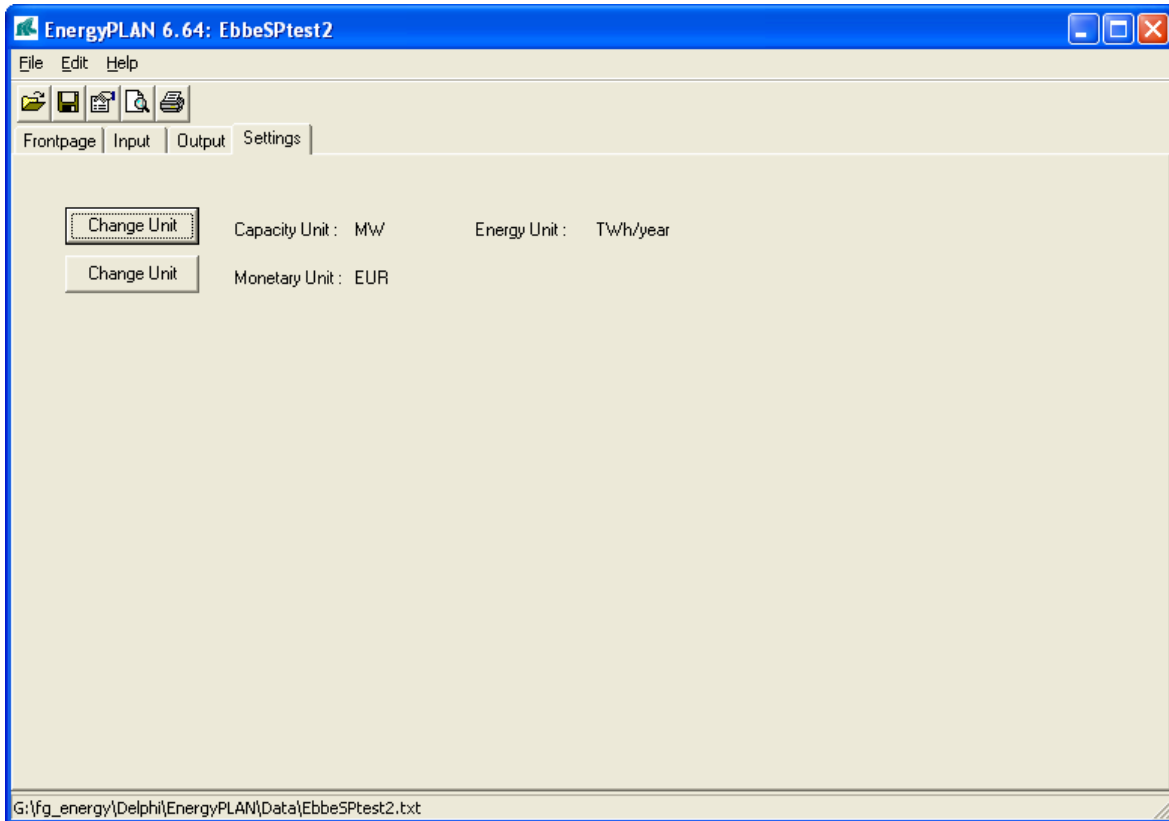


Diagram 3: Four examples of internal model data sets: Electricity demand, district heating demand, wind power production (one out of three possible), and solar heating thermal. To the left, the annual distribution on months is shown, and to the right, an example of one week of January is presented.

3.3 (Cost database)

It is planned to add a new library with different databases of investment and fuel costs.

3.4 Settings



In the settings window, one can define the energy units and monetary units.

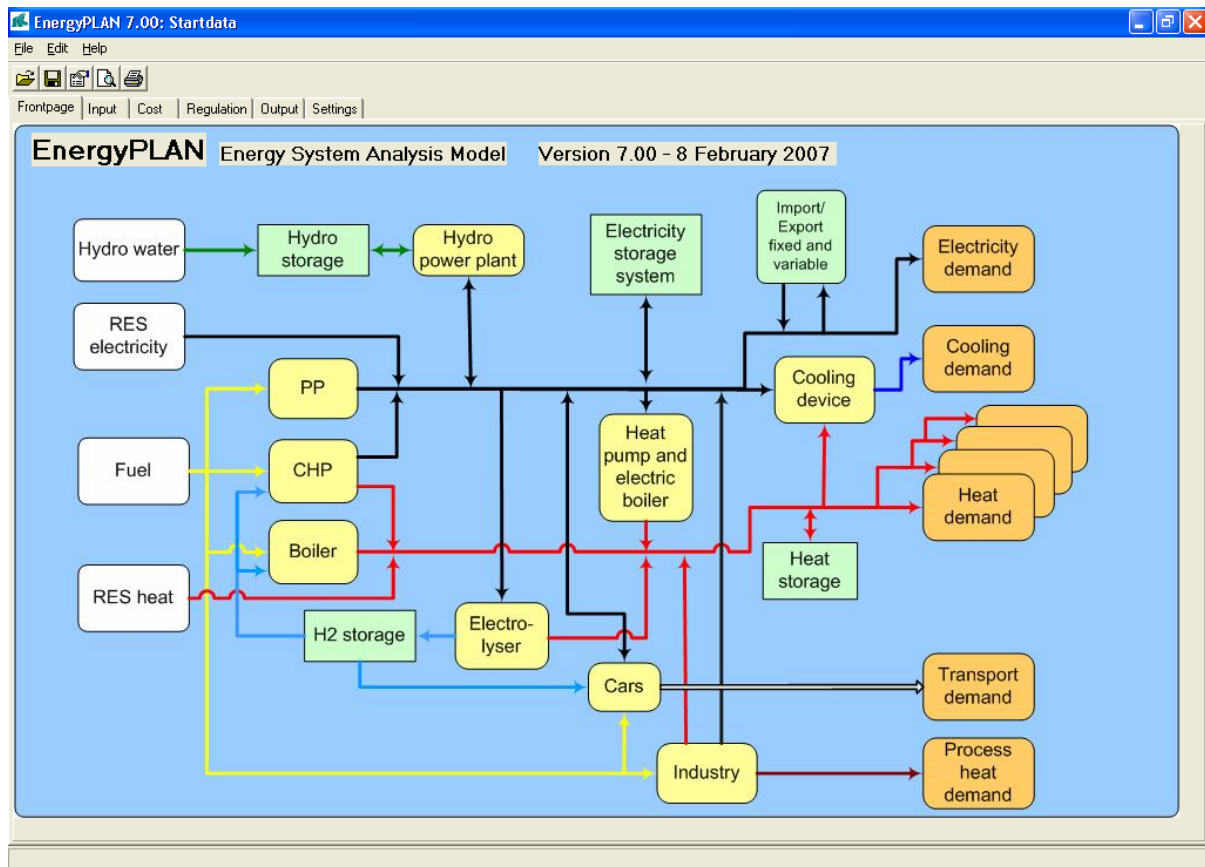
The unit is changed by activating one of the buttons “Change Unit”.

Note: No input or output numbers will be changed by activating the button. Only the writing of units in the windows and on the printed pages is changed.

The energy/capacity units can be changed by selecting between the following combinations:

- kW and GWh/year
- MW and TWh/year
- GW and PWh/year

4. Energy System Definition (Inputs)



As shown in the diagram, the EnergyPLAN model consists of the following overall structure components as illustrated in the diagram: Front page, Input, Cost, Regulation, Output and Settings.

Inputs defined by the user are presented in three sections: Input, Cost, and Regulation. In the following, each individual input window of these three sections is described, including a description of input definitions and initial calculations. Initial calculations are done simultaneously with the changing of inputs.

As shown in the diagram on the following page, the input data of the model are divided into nine sets of data: Electricity Demand, District Heating, Renewable Energy, Storage, Cooling, Individual, Industry, Transport and Waste.

Any energy system analysis - technical as well as market-economic - requires data in the "input" section. In a technical system analysis, the model does not require other inputs. But in the case of market-economic regulation or if a feasibility study is conducted, further inputs are required in the "cost" section.

By doing exercises and following the guidelines to the EnergyPLAN model, one can learn step by step how to define relevant input data. Both exercises and guidelines can be found on www.EnergyPLAN.eu.

4.1 Electricity Demand

The screenshot shows the 'Electricity Demand and Fixed Import/Export' window in EnergyPLAN 7.00. The window is divided into several sections for inputting data. The main section 'Electricity demand' has a value of 20 TWh/year. Below it, 'Electric heating (IF included)' and 'Electric cooling (IF included)' are both set to 0 TWh/year. The 'Sum (Demand excl. elec. heating)' is 20,00 TWh/year. There are also sections for 'Flexible demand' (1 day, 1 week, 4 weeks) and 'Fixed Import/Export', all currently set to 0. A diagram on the right shows a box labeled 'Import/ Export fixed and variable' with arrows pointing to and from a box labeled 'Electricity demand'.

Inputs

D_E = Annual electricity demand
 D_{EH} = Annual electricity demand for cooling (defined in the input window “Cooling”)
 D_{EC} = Annual electricity demand for heating (defined in the input window “Individual”)
 D_{EX} = Annual electricity demand of fixed exchange (Fixed import/export)
 D_{FXDay} = Annual electricity demand flexible within 1 day
 D_{FXWeek} = Annual electricity demand flexible within 1 week
 $D_{FX4Week}$ = Annual electricity demand flexible within 4 weeks
 C_{FXDay} = Max capacity of 1-day flexible demand
 C_{FXWeek} = Max capacity of 1-week flexible demand
 $C_{FX4Week}$ = Max capacity of 4-week flexible demand

The electricity demand is defined by an annual value, D_E (TWh per year) and a name of an hour by hour distribution data set. And one can also specify a fixed import/export, D_{EX} . Furthermore, one can define various kinds of flexible electricity demands, D_{FXDay} , D_{FXWeek} and $D_{FX4Week}$ in combination with maximum capacity values. Electricity demands for electric heating and cooling (specified in the “cooling” and the “individual” windows) are shown, and help functions make it possible to subtract such demands from the electricity demand.

4.1.1 Input window calculation of electricity demand

If the electricity demand contains an electric heating or cooling demand, such demand (D_{EH} and D_{EC}) can be defined and will be subtracted from the electricity demand hour by hour:

$$d_E' = d_E - d_{EH} - d_{EC}$$

$$\text{if } d_E' < 0 \text{ then } d_E' = 0$$

$$D_E' = \sum d_E'$$

If such electric heating or cooling demands are specified the new electricity demand, D_E' , will be used afterwards as input to the energy system analysis.

4.2 District Heating

EnergyPLAN 7.00: Startdata

File Edit Help

Frontpage Input Cost Regulation Output Settings

ElectricityDemand DistrictHeating RenewableEnergy Storage Cooling Individual Industry Transport Waste

CHP, Heat Pumps and Boilers at District Heating Systems:

In common for all three district heating groups:

Distribution of demand: Hour_dist-heat.txt
 Distribution of solar thermal: Hour_solar_prod1.txt
 Sum of district heating demand: 20,00 TWh/year
 Sum of solar thermal: 0,00 TWh/year

Group I: District heating gr. I is meant to represent DH systems without CHP

Demand: TWh/year Production: TWh/year Storage: GWh Loss: Percent Share: Result: TWh/year

DHP efficiency: Solar thermal:

Group II: District heating gr. II is meant to represent DH systems based on small CHP plants

Demand: TWh/year Solar thermal:

Capacities Efficiencies

CHP	MW-e		MJ/s		elec.		Therm.		COP	Heat storage gr. 2
	Capacity	Efficiency	Capacity	Efficiency	Capacity	Efficiency	Capacity	Efficiency		
1000	1250	0,4	0,5						10	

Heat Pump: Fixed Boiler share: Per cent

Boiler: Per cent

Group III: District heating gr. III is meant to represent DH systems based on large CHP extraction plants

Demand: TWh/year Solar thermal:

Capacities Efficiencies

CHP	MW-e		MJ/s		elec.		Therm.		COP	Heat storage gr. 3
	Capacity	Efficiency	Capacity	Efficiency	Capacity	Efficiency	Capacity	Efficiency		
1500	1875	0,4	0,5						10	

Heat Pump: Fixed Boiler share: Per cent

Boiler: Per cent

Condensing: Per cent

CHP extraction plants are modelled as a combination of CHP counterpressure and condensing plants
 *) Loss in percent of storage content
 **) Share of district heating demand with solar thermal

Distribution of fuel Coal Oil Ngas Biomass

(TWh/year)	Variable	Variable	Variable	Variable
DHP	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
CHP2	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
CHP3	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
Boiler2	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
Boiler3	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>
PP	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>	<input type="text" value="0"/>

Input

District heating demands

H_{DH1} = Heat demand in district heating group 1

H_{DH2} = Heat demand in district heating group 2

H_{DH3} = Heat demand in district heating group 3

Energy production units

C_{CHP2} = CHP capacity (MWe) in district heating group 2

C_{HP2} = Heat Pump capacity (MWe) in district heating group 2

T_{B2} = Boiler capacity (MJ/s) in district heating group 2

C_{CHP3} = CHP capacity (MWe) in district heating group 3

C_{HP3} = Heat Pump capacity (MWe) in district heating group 3

T_{B3} = Boiler capacity (MJ/s) in district heating group 3

C_{PP} = Power Plant capacity (MWe)

ρ_{B1} = Thermal efficiency, Boiler in district heating group 1

μ_{CHP2} = Electric efficiency, CHP in district heating group 2

ρ_{CHP2} = Thermal efficiency, CHP in district heating group 2

ρ_{B2} = Thermal efficiency, Boiler in district heating group 2

ϕ_{HP2} = COP, Heat Pump in district heating group 2

μ_{CHP3} = Electric efficiency, CHP in district heating group 3

ρ_{CHP3} = Thermal efficiency, CHP in district heating group 3

ρ_{B3} = Thermal efficiency, Boiler in district heating group 3

ϕ_{HP3} = COP, Heat Pump in district heating group 3

μ_{PP} = Electric efficiency, Power Plant

Heat storage

S_{DH2} = Capacity, Heat storage in district heating group 2 (GWh)

S_{DH3} = Capacity, Heat storage in district heating group 3 (GWh)

$S_{HSsolar1}$ = Capacity, Heat storage for solar thermal in district heating group 1 (GWh)

$S_{HSsolar2}$ = Capacity, Heat storage for solar thermal in district heating group 2 (GWh)

$S_{HSsolar3}$ = Capacity, Heat storage for solar thermal in district heating group 3 (GWh)

$LOSS_{HSsolar1}, \dots, LOSS_{HSsolar3}$ = Losses in Heat storage for solar thermal in district heating groups 1, 2 and 3.

Solar thermal

$Q_{Solar1}, \dots, Q_{Solar3}$ = Annual heat production from solar thermal in district heating groups 1, 2 and 3.

$SHARE_{Solar1}, \dots, SHARE_{Solar3}$ = Share of district heating with solar thermal in groups 1, 2 and 3.

The annual district heating consumption must be stated for each of the three DH groups. The annual solar thermal production is also defined for each group and includes heat storage capacity and losses. The share of solar is a figure between 0 and 1 defining the share of district heating demand with solar thermal production. For both district heating and solar thermal production, a common hour distribution for all three groups is specified.

Capacities and operation efficiencies of CHP units, power stations, boilers and heat pumps are defined as part of the input data. And also the size of heat storage capacities is given here.

C_{pp} is the total sum of power plant capacity and CHP capacity in group 3. In lack of district heating demand in group 3, the CHP capacity can be turned into purely condensing power plant capacity. And often CHP plants in city areas are part of extraction plants.

4.2.1 Input window calculation of solar thermal in district heating systems

The solar thermal input can not always be utilised. It depends on the hour distributions of the heat demand, the solar thermal production, the heat storage and the losses. The share of the solar thermal production, which can be utilised, Q'_{solar} , is calculated simultaneously in the input window for each of the three district heating groups. If the solar production at one hour exceeds the demand, the excess production is stored (if possible). And when the solar production is lower than the demand, the model seeks to empty the storage:

$$q'_{DH} = q_{DH} * SHARE_{Solar}$$

$$\text{If } q_{Solar} < q'_{DH} \text{ then } q'_{Solar} = q_{Solar} + \text{Min}[\text{StorageContent}, (q'_{DH} - q_{Solar})]$$

$$\text{If } q_{Solar} > q'_{DH} \text{ then } q'_{Solar} = q'_{DH} + (S_{HSsolar} - \text{StorageContent})$$

$$\text{StorageContent} := \text{StorageContent} + q_{Solar} - q'_{DH}$$

$$\text{If } \text{StorageContent} > S_{HSsolar} \text{ then } \text{StorageContent} = S_{HSsolar}$$

$$\text{StorageContent} := \text{StorageContent} - \text{StorageContent} * LOSS_{HSsolar1} / 100;$$

$$Q'_{Solar} = \sum q'_{solar}$$

Q'_{Solar} is shown in the input window for each of the three groups, and q'_{solar} is applied subsequently to the energy system analysis.

4.3 Renewable Energy Sources (RES)

Electricity production from Renewable Energy and Nuclear :

Change	Renewable Energy Source	Capacity: MW	Stabilisation share	Distribution profile	Production TWh/year	Correction factor	Post Correction production
Change	Wind	1000	0	Change Hour_wind_1.txt	2,07	0	2,07
Change	Photo Voltaic	500	0	Change Hour_wind_1.txt	1,04	0	1,04
Change	Wave Power	0	0	Change Hour_solar_prod'	0,00	0	0,00
Change	River Hydro	0	0	Change Hour_solar_prod'	0,00	0	0,00

Hydro Power :

Capacity: 0 MW-e Annual Water supply: 0 TWh/year
 Efficiency: 0,9 Distribution of water: Change Hour_wind_1.txt
 Storage: 0 GWh Estimated annual production: 0,00 TWh/year
 Pump Capacity: 0 MW-e Storage difference: 0 GWh
 Pump Efficiency: 0,9

Nuclear Power

Capacity: 0 MW-e Distribution: Change Hour_wind_1.txt
 Efficiency: 0 Annual production: 0,00 TWh/year

Input

Renewable Energy Sources

$C_{Res1}, \dots, C_{Res4}$ = Annual electricity production from Renewable Energy Resources

$Stab_{Res1}, \dots, Stab_{Res4}$ = Share of RES capacity with grid stabilisation capabilities

$FAC_{Res1}, \dots, FAC_{Res4}$ = Correction factor of RES production

Hydro power

C_{Hydro} = Capacity of Electricity Generator in MW

μ_{Hydro} = Efficiency defined as the conversion from energy in the storage into electricity production.

S_{Hydro} = Capacity of the storage in GWh

W_{Hydro} = Annual water supply to the storage in TWh/year

$C_{Hydro-Pump}$ = Capacity of the Hydro Power Pump in MW

$\alpha_{Hydro-Pump}$ = Efficiency of Pump defined as the conversion from electricity to energy in the storage

$S_{Hydro-Pump}$ = Capacity of the lower water storage in GWh

Nuclear or Geothermal

$C_{Nuclear}$ = Capacity of the Nuclear Power Electricity Generator in MW

$\mu_{Nuclear}$ = Efficiency of the Nuclear Power station.

The input data set defines input from RES and nuclear power. One can choose inputs from up to four different renewable energy sources. By pressing the button, the following specification can be attached to each RES:

- Wind
- Offshore Wind

- Photo Voltaic
- Wave Power
- River Hydro

Input to the electricity production is identified by the capacity of each RES and the by the name of the distribution file. In the case that the RES contributes to grid stabilisation, a share between 0 and 1 can be given.

Furthermore, one can specify hydro power input including reversal hydro power and either nuclear power or geothermal power.

4.3.1 Input window calculation of RES electricity production

The electricity production input from intermittent renewable energy sources such as e.g. wind power is found by multiplying the capacity by the specified hour by hour distribution. The Data Library comprises different distributions typically found from historical data.

The resulting annual production based on the specified input capacity and distribution is shown on the input page. However, different future wind turbine configurations would lead to either lower or higher productions in the same wind years. Therefore, one can choose to specify a correction factor to change the distribution and increase the annual production. The factor changes the production in such a way that the productions remain the same at hours with either no production or full production, while the other values are moderated relatively:

$$e_{Res}' = e_{Res} * 1 / [1 - FAC_{Res} * (1 - e_{Res})]$$

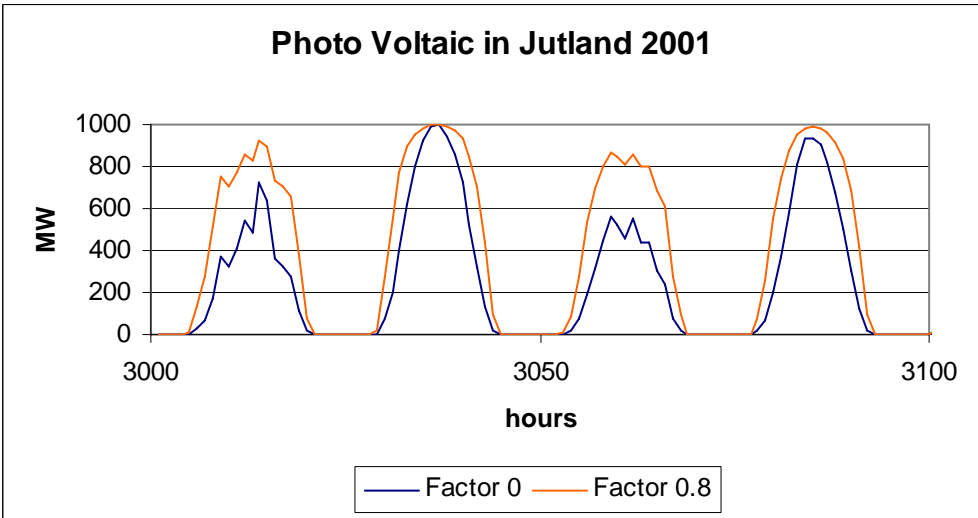
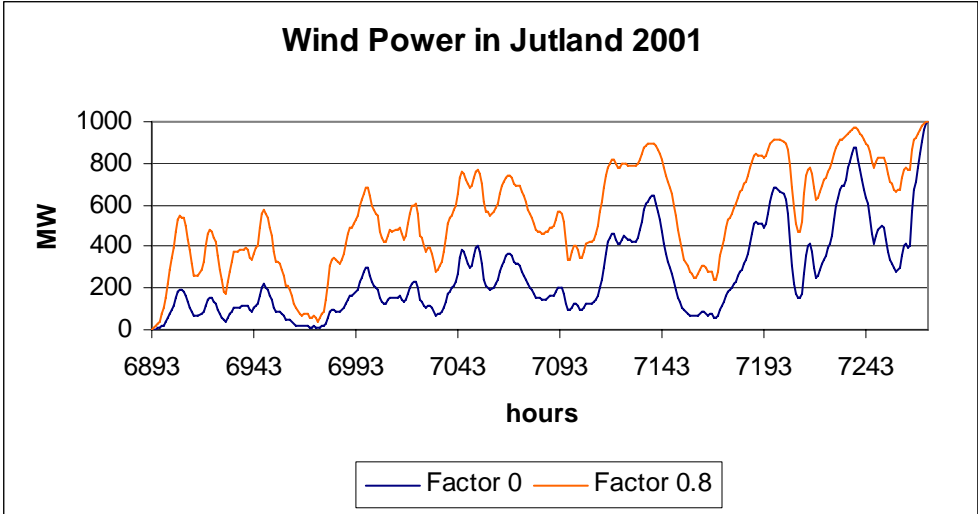
The same procedure is used for the possible modification of any of the renewable sources.

In the following diagrams, it is illustrated how the factor modifies the input. The examples are based on wind power and photovoltaic distributions in the area of western Denmark year 2001. When defining a capacity of 1000 MW wind power, the annual production becomes 1.96 TWh/year, and when defining 1000 MW of photovoltaic power, the annual production becomes 1.00 TWh/year, as shown in rows 1 and 3 in the input window below.

	Renewable Energy Source	Capacity: MW	Stabilisation share	Distribution profile	Production TWh/year	Correction factor	Post Correction production
Change	Wind	1000	0	Change hour_wind_eltra2	1,96	0	1,96
Change	Wind	1000	0	Change hour_wind_eltra2	1,96	0,8	4,10
Change	Photo Voltaic	1000	0	Change hour_PV_eltra20I	1,00	0	1,00
Change	Photo Voltaic	1000	0	Change hour_PV_eltra20I	1,00	0,8	2,02

If adding a correction factor of e.g. 0.8, the hour by hour production is modified as illustrated in the two following diagrams. The 0 values and the maximum values of 1000 MW are kept, while all the values in between those are raised in accordance with the formula described above.

As a result, annual productions are raised to 4.10 TWh/year for wind power and 2.02 TWh/year for photovoltaic power. It should be mentioned that the factor 0.8 is very high especially for photovoltaic power. However, such a high factor is suitable for the illustration of the principle of modifications.



4.3.2 Input window calculation of hydro power

The hydro power plant is identified by an hourly distribution of the annual water input (W_{Hydro}), a water storage capacity (S_{Hydro}) and the capacity (C_{Hydro}) and efficiency (μ_{Hydro}) of the generator.

Based on such input, the potential output is calculated simultaneously by the procedure described in the following.

First, the average hydro electricity production ($e_{Hydro-ave}$) is calculated as the output of the average water supply (Annual water supply divided by 8784 hours/year):

$$e_{\text{Hydro-ave}} = \mu_{\text{Hydro}} * W_{\text{Hydro}} / 8784$$

Then the program calculates the hour by hour modelling of the system, including the fluctuations in the storage content. Furthermore, the hydro power production (e_{Hydro}) is modified in accordance with the generator capacity, the distribution of the water supply, and the storage capacity in the following way:

$$\text{Hydro-storage-content} = \text{Hydro-storage content} + w_{\text{Hydro}}$$

$$e_{\text{Hydro}} = \text{MAX} [e_{\text{Hydro-Ave}}, (\text{Hydro-storage-content} - S_{\text{Hydro}}) * \mu_{\text{Hydro}}]$$

$$e_{\text{Hydro}} \leq C_{\text{Hydro}}$$

Due to differences in the storage content at the beginning and at the end of the calculation period errors may appear in the calculations. To correct these, the above calculation seeks to identify a solution in which the storage content at the end is the same as at the beginning. Initially, the storage content is defined as 50% of the storage capacity. After the first calculation, a new initial content is defined as the resulting content at the end of the former calculation.

The annual potential production of the hydro power plant is calculated and shown in the input window.

4.3.3 Input window calculation of nuclear power or geothermal power.

By activating the button with the name, one can choose to include either nuclear power or geothermal power in the input. Both types of power production are calculated the same way, here described for the nuclear power plants.

Nuclear power units are determined by the following inputs:

C_{Nuclear} = Capacity of the nuclear power electricity generator in MW

μ_{Nuclear} = Efficiency of the nuclear power station.

d_{Nuclear} = Distribution of the electricity production between 8784 hour values

The nuclear power station is subject to the condition that it will always be involved in the task of maintaining grid stability.

The nuclear unit is considered to be running as base load, and therefore the power plant does not take part in the active regulation. The electricity production of the nuclear unit (e_{Nuclear}) is simply defined by the capacity and the hour by hour distribution:

$$e_{\text{Nuclear}} = C_{\text{Nuclear}} * d_{\text{Nuclear}} / \text{Max}(d_{\text{Nuclear}})$$

The efficiency is used only for the calculation of the annual amount of fuel (f_{Nuclear}) which is calculated by applying the following formula:

$$f_{\text{Nuclear}} = e_{\text{Nuclear}} / \mu_{\text{Nuclear}}$$

The fuel consumption is named “Uranium” and is measured in TWh/year in order to be able to compare it to the consumption of the rest of the units. In the case of geothermal, the fuel is named “Geothermal”.

4.4 Storage

EnergyPLAN 7.00: Startdata

File Edit Help

Frontpage Input Cost Regulation Output Settings

ElectricityDemand DistrictHeating RenewableEnergy Storage Cooling Individual Industry Transport Waste

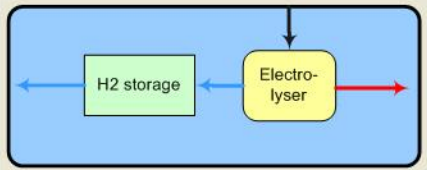
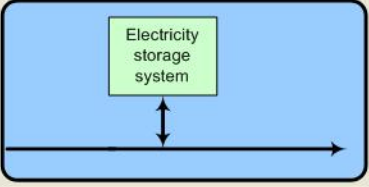
Electrolysers and electricity storage systems

Electrolyser	Capacities		Efficiencies		Hydrogen Storage
	MW-e	MJ/s	fuel	Therm.	
Group 2	0	0	0,8	0,1	0 GWh
Group 3	0	0	0,8	0,1	0 GWh
Transport	0		0,8		0 GWh
Micro CHP	0		0,8		0 GWh

Electricity Storage	Capacities		Efficiencies	Fuel Ratio *)	Storage Capacity
	Pump	Turbine			
Pump	0		0,8		0 GWh
Turbine	0		0,9	0	

*) Fuel ratio = fuel input / electric output (for CAES technologies or similar)

Advanced CAES

Input

Electrolysers

- C_{Eic2} = Capacity of Electrolysers in district heating group 2
- C_{Eic3} = Capacity of Electrolysers in district heating group 3
- C_{EicT} = Capacity of Electrolysers for Transportation
- C_{EicM} = Capacity of Electrolysers for Micro CHP
- α_{Eic2} = Fuel efficiency of Electrolysers in district heating group 2
- α_{Eic3} = Fuel efficiency of Electrolysers in district heating group 3
- α_{EicT} = Fuel efficiency of Electrolysers for Transportation
- α_{EicM} = Fuel efficiency of Electrolysers for Micro CHP
- ρ_{Eic2} = Thermal efficiency of Electrolysers in district heating group 2
- ρ_{Eic3} = Thermal efficiency of Electrolysers in district heating group 3
- S_{Eic2} = Capacity of Electrolysers Fuel Storage in district heating group 2
- S_{Eic3} = Capacity of Electrolysers Fuel Storage in district heating group 3
- S_{EicT} = Capacity of Electrolysers Fuel Storage, Transportation
- S_{EicM} = Capacity of Electrolysers Fuel Storage, Micro CHP

Electricity Storage

- C_{Pump} = Capacity of Pump in electricity storage
- $C_{Turbine}$ = Capacity of Turbine in electricity storage
- S_{CAES} = Capacity of Storage, electricity storage system
- α_{Pump} = Efficiency of Pump in electricity storage (from electricity to storage input)
- $\mu_{Turbine}$ = Efficiency of Turbine in electricity storage (from storage output to electricity)
- ϕ_{CAES} = Fuel-ration for CAES systems (fuel input / electric output)

In the storage input window, one can specify electrolyser and electricity storage systems. The two first electrolysers are described in the model as located in either district heating group 2 or group 3 along with the CHP units, Heat Pumps and boilers. The two next electrolysers are used for hydrogen

production for transportation or micro CHP. The electrolyzers transform electricity into fuel and heat if located in connection to district heating. They are defined by a capacity, a fuel efficiency and a thermal efficiency. Moreover, fuel storage is defined by a capacity.

The electricity storage can represent e.g. hydro pump storage, a battery or a FC/electrolyser hydrogen storage and is represented by the following inputs:

- Pump (converting electricity to potential energy) defined by a capacity and an efficiency
- Turbine (converting potential energy to electricity) defined by a capacity and an efficiency
- Storage (storing energy) defined by a capacity.

Also the model can add fuel when the turbine is activated and thereby technologies such as CAES (Compressed Air Energy Storage) can be modelled. In such case, the following input has to be defined:

- CAES fuel ratio defined as CAES fuel consumption / electric output.

4.5 Cooling

The screenshot shows the 'Cooling systems' configuration window in EnergyPLAN 7.00. The window title is 'Cooling systems: Electric airconditioning and District heating for cooling'. Below the title, there is a 'Distribution of cooling demand' section with a 'Change' button and a file name 'Hour_distr-heat.txt'. A table is present with columns for 'TWh/year', 'Electricity Consumption', 'Heat Consumption', 'COP', and 'Cooling Demand'. The table contains several rows for different cooling methods, including 'Electricity for cooling' and 'District heating for cooling DH gr. 1, 2, and 3'. To the right of the table is a flow diagram showing a 'Cooling device' box with an arrow pointing to a 'Cooling demand' box, and a red arrow pointing up to the 'Cooling device' box.

TWh/year	Electricity Consumption	Heat Consumption	COP	Cooling Demand
Electricity for cooling :	<input type="text" value="0"/>	<input type="text" value="2"/>	<input type="text" value="2"/>	0,00
District heating for cooling DH gr. 1	<input type="text" value="0"/>	<input type="text" value="2"/>	<input type="text" value="2"/>	0,00
District heating for cooling DH gr. 2	<input type="text" value="0"/>	<input type="text" value="2"/>	<input type="text" value="2"/>	0,00
District heating for cooling DH gr. 3	<input type="text" value="0"/>	<input type="text" value="2"/>	<input type="text" value="2"/>	0,00
		0,00		0,00

Input

D_{Cool} = Annual electricity demand for cooling

$H_{Cool1}, \dots, H_{Cool3}$ = Annual heat demands for cooling in groups 1, 2 and 3.

Cooling demands are defined by annual electricity consumptions (air-conditioning etc.) and/or by annual heat consumption (absorption technology). In the latter case, heat consumption is divided into 3 district heating groups. One common hour distribution is used for all cooling demands. Inputs can also be defined in terms of COPs of the different demands. Such co-efficiencies are used in the input window only to calculate a “Cooling” demand. This function is meant to provide assistance in case one demand is replaced with another, e.g. an air-conditioning electricity demand with a COP of 3 is replaced with a district heating absorption cooling with a COP of 2.

Later, in the energy systems, the heat demands for cooling are simply added hour by hour to the district heating demands in the various groups. The electricity demand for cooling is added to the other electricity demands. Please note that a help function in the Input Electricity Demand window allows for a subtraction of electricity for cooling and heating from the fixed electricity demand.

4.6 Individual

EnergyPLAN 7.00: Startdata

File Edit Help

Frontpage Input Cost Regulation Output Settings

ElectricityDemand DistrictHeating RenewableEnergy Storage Cooling Individual Industry Transport Waste

Heat supply and distributed generation from households

Distribution of heat demand: Hour_distr-heat.txt Distribution of solar thermal: Hour_solar1_prod.txt

TWh/year	Fuel Consumption Input	Fuel Consumption Output	Efficiency Thermal	Heat Demand	Efficiency Electric	Capacity Limit **)	Electricity Production	Heat Storage *)	Solar Thermal Share ***)	Solar Thermal Input	Solar Thermal Output
Coal boiler :	<input type="text" value="0"/>	0,00	0,7	0,00				<input type="text" value="0"/>	<input type="text" value="1"/>	<input type="text" value="0"/>	0,00
Oil boiler :	<input type="text" value="0"/>	0,00	0,8	0,00				<input type="text" value="0"/>	<input type="text" value="1"/>	<input type="text" value="0"/>	0,00
Ngas boiler :	<input type="text" value="0"/>	0,00	0,9	0,00				<input type="text" value="0"/>	<input type="text" value="1"/>	<input type="text" value="0"/>	0,00
Biomass boiler :	<input type="text" value="0"/>	0,00	0,7	0,00				<input type="text" value="0"/>	<input type="text" value="1"/>	<input type="text" value="0"/>	0,00
H2 micro CHP :	0,00	0,5	0	0,3	1	0,00		<input type="text" value="0"/>	<input type="text" value="1"/>	<input type="text" value="0"/>	0,00
Ngas micro CHP :	0,00	0,5	0	0,3	1	0,00		<input type="text" value="0"/>	<input type="text" value="1"/>	<input type="text" value="0"/>	0,00
Biomass CHP :	0,00	0,5	0	0,3	1	0,00		<input type="text" value="0"/>	<input type="text" value="1"/>	<input type="text" value="0"/>	0,00
Heat Pump :					3	1	0,00	<input type="text" value="0"/>	<input type="text" value="1"/>	<input type="text" value="0"/>	0,00
Electric heating :				23			-23,00	<input type="text" value="0"/>	<input type="text" value="1"/>	<input type="text" value="0"/>	0,00
Total :		0,00		23,00			-23,00				0,00

*) The capacity of the heat storage is given in days of average heat demand
 **) The capacity limit of the CHP and HP is given in share (between 0 and 1) of maximum heat demand
 ***) Share of heat consumers with solar thermal

Indbakke - Outlook Express

Input

Individual boilers, CHP, Heat pumps and Electric Heating

F_{M-Coal} , F_{M-Oil} , F_{M-Ngas} , F_{M-bio} = Annual fuel demands for individual boilers

ρ_{M-coal} , ρ_{M-oil} , ρ_{M-ngas} , ρ_{M-bio} = Thermal efficiencies of individual boilers

$H_{M-H2CHP}$, $H_{M-NgasCHP}$, $H_{M-BioCHP}$ = Annual heat demands of micro CHP on H2, Natural gas and Biomass.

$\mu_{M-H2CHP}$, $\mu_{M-NgasCHP}$, $\mu_{M-BioCHP}$ = Efficiencies (electric) of micro CHP on H2, Natural gas and Biomass.

$\rho_{M-H2CHP}$, $\rho_{M-NgasCHP}$, $\rho_{M-BioCHP}$ = Efficiencies (thermal) of micro CHP on H2, Natural gas and Biomass.

H_{M-HP} , H_{M-EH} = Annual heat demand of Heat Pumps and Electric Heating in individual houses

ϕ_{I-HP} = COP of Heat Pumps in individual houses

$LIMIT_{M-H2CHP}$, $LIMIT_{M-NgasCHP}$, $LIMIT_{M-BioCHP}$, $LIMIT_{I-HP}$ = Capacity Limit of CHP and HP (between 0 and 1)

Solar thermal and heat storage

$Q_{Solar-M-coal}$, ... $Q_{Solar-M-bio}$ = Annual heat production from solar thermal in individual boiler systems.

$Q_{Solar-M-H2CHP}$, ... $Q_{Solar-M-bioCHP}$ = Annual heat production from solar thermal in individual CHP systems.

$Q_{Solar-M-HP}$, $Q_{Solar-M-EH}$ = Annual heat production from solar thermal in individual HP and EH systems.

$SHARE_{Solar-M-coal}$, ... $SHARE_{Solar-M-EH}$ = Share of individual houses with solar thermal in various systems.

$S_{HSolar-M-coal}$, ... $S_{HSolar-M-EH}$ = Capacity, Heat storage for solar thermal in various systems

Inputs to individual houses are basically defined as fuel inputs, since such figures are normally basic data in statistics. When defining efficiencies of boilers, heat demands are calculated. Electric heating is defined as electricity consumption. The same hourly distributions are used for all heat demands.

To include CHP and Heat Pumps one has to define heat demands and efficiencies. Moreover, one can define capacity limits in the CHP and Heat Pump units in shares of the maximum heating demand (figures between 0 and 1). If such limits are defined, the peak heat demands will be met by boilers using the same efficiencies as defined for the boiler-only systems. In the case of H₂, the efficiency of the natural gas boiler is used; and in the case of Heat Pumps, electric heating is used.

Moreover, one can add solar thermal power to all the systems by defining the annual solar production and the share of heat demand based on solar thermal power. For all solar thermal productions, the same hourly distributions are used.

The following are calculated on a simultaneous basis in the input window:

4.6.1 Input window calculation of heat demands in individual houses

The resulting heat demands in the individual houses are given as input to the micro CHP and Heat Pump systems. For the boiler-only systems, the heat demands are calculated simply as the fuel input multiplied by the boiler efficiencies:

$$H = F / \rho$$

4.6.2 Input window calculation of solar thermal production in individual houses

Solar production is calculated principally in the same way as solar thermal production in district heating. If the solar production at one hour exceeds the demand, the excess production is stored if possible, and if not, the excess production is perceived as waste. When the solar production is lower than the demand the model seeks to empty the storage. The same calculation methodology is used as in section 4.2.1.

4.6.3 Input window calculation of boilers, CHP and heat pumps in individual houses

The *heat demand* for solar production is supplied by boilers, micro CHPs and heat pumps. The production in the boilers-only systems is simply calculated as the difference between the demand and the solar production (including the use of the heat storage):

$$q_{M-Oil} = h_{M-Oil} - q'_{Solar-M-Oil}$$

For the micro CHP and the Heat Pump the production cannot exceed the limitations in capacity if any.

$$q_{M-NgasCHP} = h_{M-NgasCHP} - q'_{Solar-M-NgasCHP}$$

If $q_{M-NgasCHP} > \text{Max}(h_{M-NgasCHP}) * \text{LIMIT}_{M-NgasCHP}$ then $q_{M-NgasCHP} = \text{Max}(h_{M-NgasCHP}) * \text{LIMIT}_{M-NgasCHP}$

The heat demand remaining after coverage by solar (including the use of storage), CHP and Heat Pumps is met by boilers and in the case of heat pumps by electric heating:

$$q_{M-H2CHP-Boiler} = h_{M-H2CHP} - q'_{Solar-M-H2CHP} - q_{M-H2CHP}$$

$$q_{M-NgasCHP-Boiler} = h_{M-NgasCHP} - q'_{Solar-M-NgasCHP} - q_{M-NgasCHP}$$

$$q_{M-BioCHP-Boiler} = h_{M-BioCHP} - q'_{Solar-M-BioCHP} - q_{M-BioCHP}$$

$$q_{M-HP-EH} = h_{M-HP} - q'_{Solar-M-HP} - q_{M-HP}$$

The *fuel demands* for all boiler systems are calculated and shown in the input window (Here shown for the oil boiler):

$$f_{M-Oil} = q_{M-Oil} / \rho_{M-Oil}$$

The fuel demands for the three CHP systems (here shown for the Ngas system) are calculated individually for the CHP unit and the peak load boiler.

$$f_{M-NgasCHP} = q_{M-NgasCHP} / \rho_{M-NgasCHP}$$

$$f_{M-NgasCHP-Boiler} = q_{M-NgasCHP-Boiler} / \rho_{M-Ngas}$$

The total fuel demand, $F_{M-NgasCHP-Total}$, is found by adding the two demands:

$$f_{M-NgasCHP-Total} = f_{M-NgasCHP-Boiler} + f_{M-NgasCHP}$$

The *electricity production* from CHP is calculated as follows:

$$e_{M-NgasCHP} = f_{M-NgasCHP} * \mu_{M-NgasCHP}$$

The total *electricity consumption* from Heat Pumps, $D_{I-HP-Total}$, is calculated as follows:

$$d_{M-HP-EH} = q_{M-HP-EH}$$

$$d_{M-HP} = q_{M-HP} / \phi_{M-HP}$$

$$d_{M-HP-total} = d_{M-HP-EH} + d_{M-HP}$$

The electricity demand for electric heating is calculated like this:

$$D_{M-EH} = q_{M-EH}$$

The resulting total fuel consumption and electricity productions (and consumptions) are shown in the input window for all systems. So is the resulting solar production.

4.6.4 Input window calculation of Electrolysers for micro H2 CHP systems

If a heat demand is specified for the micro H2 CHP system, then the minimum electrolyser capacity required to provide the necessary hydrogen is calculated. The electrolysers must be added to the system in the Input Storage window. If hydrogen storage is specified in the Input Storage window, then such storage capacity is taken into account. The minimum electrolyser capacity, $C_{ELC-MIN}$, is calculated in the following way:

First, the hydrogen production of the electrolyser f_{ElcM} is defined as the average hydrogen consumption of the micro CHP system, $f_{M-H2CHP-Average}$:

$$f_{ElcM} = f_{M-H2CHP-Average} = F_{M-H2CHP} / 8784$$

Then for each hour x the hydrogen storage content is calculated, $s_{ElcM}(x)$, as the content of the previous hour plus the average production minus the actual consumption of the hour.

$$s_{ElcM}(x) = s_{ElcM}(x-1) + f_{M-H2CHP-Average} - f_{M-H2CHP}(x)$$

If at one hour the storage content exceeds the capacity, the production is decreased:

$$\mathbf{If} \ S_{\text{ElcM}} > S_{\text{ElcM}} \ \mathbf{then} \ f_{\text{ElcM}} = f_{\text{ElcM}} - (S_{\text{ElcM}} - S_{\text{ElcM}})$$

And if the storage content goes below zero, the production is increased:

$$\mathbf{If} \ S_{\text{ElcM}} < 0 \ \mathbf{then} \ f_{\text{ElcM}} = f_{\text{ElcM}} - S_{\text{ElcM}}$$

Due to differences in the storage content at the beginning and at the end of the calculation period, errors may appear in the calculation. To correct these errors the above calculation seeks to identify a solution in which the storage content at the end is the same as at the beginning. Initially, the storage content is defined as 50% of the storage capacity. After the first calculation, a new initial content is defined as the resulting content at the end of the former calculation.

Finally, the minimum electrolyser capacity, $C_{\text{Elc-MIN}}$, is found as the maximum production needed divided by the fuel efficiency:

$$C_{\text{Elc-MIN}} = \text{Hourmax}(f_{\text{ElcM}}) / \alpha_{\text{ElcM}}$$

Also the corresponding electricity demand d_{ElcM} can be calculated:

$$d_{\text{ElcM}} = f_{\text{ElcM}} / \alpha_{\text{ElcM}}$$

The electricity demand d_{ElcM} forms the basis for the further calculation in section 6.7.1, in which the electrolyzers are used for decreasing excess and power only production in the system.

4.7 Industry

EnergyPLAN 7.00: Startdata

File Edit Help

Frontpage Input Cost Regulation Output Settings

ElectricityDemand DistrictHeating RenewableEnergy Storage Cooling Individual Industry Transport Waste

Industry: Fuel consumption and Heat and power production

	Coal	Oil	Ngas	Biomass
Industry	0	0	0	0
Various	0	0	0	0

Industrial CHP (CSHP): Hour_cshpel.txt

TWh/year	DH prod	Electricity prod
DH Gr.1:	0	0
DH Gr.2:	0	0
DH Gr.3:	0	0
Total:	0,00	0,00

Input

F_{I-Coal} , F_{I-Oil} , F_{I-Ngas} , F_{I-bio} = Annual fuel demands for Industry
 F_{V-Coal} , F_{V-Oil} , F_{V-Ngas} , F_{V-bio} = Annual fuel demands for Various
 Q_{I1} , ..., Q_{I3} = Annual excess heat production from industry to district heating groups 1, 2 and 3.
 E_{CSHP1} , ..., E_{CSHP3} = Annual excess electricity production from industrial CHP (CSHP)

Inputs to Industry are basically defined as fuel inputs, since such figures are normally basic data in statistics. Moreover, electricity and excess heat productions from industrial CHP or similar are defined, which are fed into one of the three district heating groups.

Heat production for district heating groups is given priority along with solar thermal and heat production from waste as explained in section 5.5 (for group 1) and in sections 6.2.1 or 7.4 (for groups 2 and 3).

Electricity production can be specified for each of the three district heating groups. However, they are all fed into the grid and given priority along with renewable energy resources such as wind power. Other units such as CHP and power plants will adjust their production accordingly if possible (given the specified regulation strategy), and if this can not be done, excess electricity production will be exported.

4.8 Transport

The screenshot shows the 'Transport' input window in EnergyPLAN 7.00. It includes input fields for fuel demands in TWh/year: JP (Jet Fuel), Diesel, Petrol, Ngas, Biomass, H2 (Produced by Electrolysers), Electricity (Dump Charge), and Electricity (Smart Charge). There are also 'Change' buttons and file paths for H2 and Electricity inputs. Below these are EV (smart) details and V2G details, including capacity and efficiency parameters. A 'Help to design inputs' button is located in the upper right. To the right of the input fields is a flowchart diagram illustrating energy flows: Oil, Ngas, and Biomass feed into 'Combustion cars', which then lead to 'Transport demand'. H2 storage feeds into 'FC' (Fuel Cell), which also leads to 'Transport demand'. Electricity feeds into 'Electric vehicle' and 'Vehicle to grid', both leading to 'Transport demand'. The 'Vehicle to grid' also has a bidirectional arrow with 'Electricity'.

Input

Fuel demands

F_{T-JF} , $F_{T-Diesel}$, $F_{T-Petrol}$, F_{T-Ngas} , F_{T-bio} = Annual fuel demands for Transportation

$F_{T-Transport-H2}$ = Annual hydrogen fuel demand for transportation

Electricity demands

D_{BEV} = Electricity demand of Battery Electric Vehicles in TWh/year

D_{V2G} = Electricity demand of “V2G cars” and or “BEV smart charge” in TWh/year

$V2G_{Max-Share}$ = The maximum share of cars which are driving during peak demand hour.

$C_{Charger}$ = The capacity of the grid to battery connection in MW

$V2G_{Connection-Share}$ = The share of parked V2G cars connected to the grid.

$\mu_{Charger}$ = The efficiency of the grid to battery connection (charger).

$S_{V2G-Battery}$ = The capacity of the battery storage in GWh

C_{Inv} = The capacity of the battery to grid connection in MW

μ_{Inv} = The efficiency of the battery to grid connection (inverter).

The transport input window is designed to describe potential changes in the transport sector.

The fuel inputs at the top comprise fuel for cars and other transport units divided into Jet Petrol, Diesel, Petrol, natural gas, and biomass. Then vehicles on hydrogen or biofuels produced on waste.

A series of inputs describes battery electric vehicles (BEV). Basically, they are divided into dump cars and smart cars. In the case of dump cars, the input defines an electricity demand for transportation shown as an annual demand and a distribution curve. In the case of smart cars, the electricity demand forms part of the regulations and one has to specify a number of relevant input data. One can activate a help function by pressing the button in the upper right corner of the window, as illustrated in the following window. By specifying the efficiency of the individual types of cars in terms of km/kWh, one can follow the total numbers of km per year during the process of changing the system, e.g. by

reducing the number of traditional cars and adding new technologies on biomass and/or electric vehicles.

4.8.1 Input window calculation of electrolyzers for transportation

If a fuel demand is specified for hydrogen transportation then the minimum electrolyser capacity required to provide the necessary hydrogen is calculated. The electrolyzers must be added to the system in the Input Storage window. The calculation is the same as for micro hydrogen systems as shown in section 4.6.4.

The screenshot shows the 'Transport' window in EnergyPLAN 7.00. The window is titled 'Transport:' and contains a table of input parameters. The table has three columns: 'TWh/year', 'km/kWh', and 'Billion km/year'. The rows represent different fuel types and their associated energy consumption and transport distance. A 'Max. share of cars during peak demand' field is located at the bottom of the window. A diagram on the right side of the window shows energy flows from various sources to different components.

Fuel Type	TWh/year	km/kWh	Billion km/year
JP (Jet Fuel)	0		
Diesel	0	1,5	0
Petrol	0	1,5	0
Ngas	0	1,5	0
Biofuels from waste	0,00	1,4	0
Biomass	0	1,5	0
H2 (Produced by Electrolysers)	0	3	0
Electricity (Dump Charge)	0	5	0
Electricity (Smart Charge)	0	5	0
Max. share of cars during peak demand	0,2		0

4.9 Waste

Waste: Heat, electricity and biofuel from energy conversion of waste

Waste is defined geographical on the three district heating groups. Only one hour distribution can be defined and storage of waste is not considered an option. Heat production is utilised and given priority in the respective district heating groups. Electricity production is fed into the grid. Biofuel production for transportation is transferred to the transportation window. And biofuels for CHP and boilers is subtracted from the fuels in the respective district heating group. "Various" represent non energy products such as food. The economic value is subtracted from the cost of the waste energy recourse.

Distribution of Waste: const.txt

	Waste input (TWh/year)	DH production		Electricity production		Biofuel transportation		Biofuel CHP-Boiler		Various (Food etc.)		MDKK/TWh	
		Efficiency	TWh/y	Efficiency	TWh/y	Efficiency	TWh/y	Efficiency	TWh/y	Efficiency	TWh/y		
DH Gr.1:	0	0,8	0,00	0	0,00	0	0,00	0	0,00	0	0,00	1	0,00
DH Gr.2:	0	0,8	0,00	0	0,00	0	0,00	0	0,00	0	0,00	1	0,00
DH Gr.3:	0	0,8	0,00	0	0,00	0	0,00	0	0,00	0	0,00	1	0,00
Total:	0,00		0,00		0,00		0,00		0,00		0,00		0,00 MDKK

Input

F_{W1}, F_{W2}, F_{W3} = Annual input of waste fuels divided into the three district heating groups

$\rho_{W1}, \rho_{W2}, \rho_{W3}$ = Efficiencies (thermal) of waste conversion

$\mu_{W1}, \mu_{W2}, \mu_{W3}$ = Efficiencies (electric) of waste conversion

$\psi_{W1}, \psi_{W2}, \psi_{W3}$ = Efficiencies (waste to biofuel for transportation) of waste conversion

$\eta_{W1}, \eta_{W2}, \eta_{W3}$ = Efficiencies (waste to biofuel for CHP and boilers) of waste conversion

$\tau_{W1}, \tau_{W2}, \tau_{W3}$ = Efficiencies (waste to various non energy products) of waste conversion

P_{W1}, P_{W2}, P_{W3} = Prices of various non energy products (MDKK/TWh)

Waste is considered biomass energy, which can not be stored but has to be burned continuously. Waste is divided geographically into three district heating groups and only one hourly distribution can be defined.

Waste can be converted into the following:

- heat production, which is given priority in the three district heating groups
- electricity production which is being fed into the grid
- biofuels (fluid) for transportation, which are transferred to the Input Transport window
- biofuels (solid) for CHP and boilers, which are subtracted from the fuels in the respective DH groups
- Various (non energy) products which are given an economic value.

The following input must be given to the model:

- The waste resources divided geographically between the three district heating systems mentioned above.
- Efficiencies specifying the quantity of the waste input resources converted into the following 4 energy forms: Heat for district heating, electricity, fuel for transportation and fuel for CHP and boilers.
- An hour by hour distribution of the waste input (heat and electricity output)

Moreover, one can specify an additional non energy output (such as animal food) which will then be given an economic value in the feasibility study.

Basically, the model assumes that waste can not be stored and has to be converted in accordance with the specified hour by hour input. Consequently, the energy outputs are treated in the following way:

Heat production for district heating is given priority along with solar thermal and industrial waste heat production. If such input can not be utilized because of limitations in demand and heat storage capacity, the heat is simply wasted.

Electricity production is fed into the grid and given priority along with renewable energy resources such as wind power. Other units such as CHP and power plants will adjust their production accordingly if possible (given the specified regulation strategy), and if this can not be done, excess electricity production will be exported.

Fuel for transport is calculated and the used fuel can subtract the petrol accordingly and, at the same time, adjust for differences in car efficiencies if any.

Fuel for CHP and boilers is automatically subtracted in the calculation of fuel in the relevant district heating groups.

4.9.1 Calculation of waste fuel outputs

The biofuel outputs are calculated in the following way and the fuel for transportation is transferred to the Transport window:

$$F_{T\text{-Waste}} = FW1 * \psi_{W1} + FW2 * \psi_{W2} + FW3 * \psi_{W3}$$

4.10 Fuel Cost

Fuel, Taxes and CO2 costs

	Coal	FuelOil	Diesel Gasoil	Petrol/JP	Ngas	Waste	Biomass
Fuel Price (world market prices) (DKK/GJ)	0	0	0	0	0	+ 0	0
Fuel handling costs (distribution and refinery) (DKK/GJ)							
To central CHP and power stations	0	0		0	0	0	0
To dec. CHP, DH and Industry	0	0		0	0	0	0
To individual house holds	0		0	0	0		0
To transportation (road and train)			0	0	0		0
To transportation (air)				0			
Taxes (DKK/GJ)							
Individual households	0		0	0			0
Industry	0	0		0	0	0	0
Boilers (at CHP and DH plants)	0	0		0	0	0	0
CHP units	0	0		0	0	0	0
Compressed Air Energy Storage (CAES)				0			
CO2 content in th fuels:	0	0		0	0		(kg/GJ)
CO2 Price (included in marginal production prices)	0		(DKK/t CO2)				

Business economic operation:
All costs (fuel, handling and taxes) are included in the marginal costs when optimal operation strategies for the individual plants are decided.

Socio economic consequences:
Taxes are not included when the socio economic consequences are calculated.

Taxes on electricity for energy conversion :

(DKK/MWh)	DH systems	Individual houses
Electric heating	0	0
Heat Pumps	0	0
Electrolysers	0	0
Electric cars		0
Pump (storage)	0	

Fuel price alternative :

Input

Fuel world market prices, handling costs and taxes (DKK/GJ)

$P_{Coal-WM}, P_{FuelOil-WM}, P_{Diesel-WM}, P_{Petrol-WM}, P_{Ngas-WM}, P_{Waste-WM}, P_{Biomass-WM}$ = World Market Fuel Prices
 $P_{Coal-Hcen}, P_{FuelOil-Hcen}, P_{Ngas-Hcen}, P_{Waste-Hcen}, P_{Biomass-Hcen}$ = Fuel Handling costs to central power plants
 $P_{Coal-Hdec}, P_{FuelOil-Hdec}, P_{Ngas-Hdec}, P_{Waste-Hdec}, P_{Biomass-Hdec}$ = Fuel Handling costs to decentralised CHP and industry
 $P_{Coal-HIndv}, P_{Diesel-HIndv}, P_{Ngas-HIndv}, P_{Biomass-HIndv}$ = Fuel Handling costs to individual households
 $P_{Diesel-HRoad}, P_{Petrol-HRoad}, P_{JP-HAir}, P_{Ngas-HRoad}, P_{Biomass-HRoad}$ = Fuel Handling costs to transportation
 $P_{Coal-TaxIndv}, P_{Diesel-TaxIndv}, P_{Ngas-TaxIndv}, P_{Biomass-TaxIndv}$ = Taxes on Fuels to individual households
 $P_{Coal-TaxI}, P_{FuelOil-TaxI}, P_{Ngas-TaxI}, P_{Waste-TaxI}, P_{Biomass-TaxI}$ = Taxes on Fuels to waste incineration and industry
 $P_{Coal-TaxB}, P_{FuelOil-TaxB}, P_{Ngas-TaxB}, P_{Waste-TaxB}, P_{Biomass-TaxB}$ = Taxes on Fuels to district heating boilers
 $P_{Coal-TaxCHP}, P_{FuelOil-TaxCHP}, P_{Ngas-TaxCHP}, P_{Waste-TaxCHP}, P_{Biomass-TaxCHP}$ = Taxes on Fuels to CHP production
 $P_{Ngas-TaxCAES}$ = Taxes on fuel for CAES installations

CO2 trade price and Electricity taxes on heat and hydro productions (DKK/MWh)

$P_{Elec-TaxEH-DH}, P_{Elec-TaxHP-DH}, P_{Elec-TaxElc-DH}, P_{Elec-TaxCAES-DH}$: Taxes on electricity in district heating systems
 $P_{Elec-TaxEH-Indv}, P_{Elec-TaxHP-Indv}, P_{Elec-TaxElc-Indv}, P_{Elec-TaxBEV-Indv}$: Taxes on electricity in individual houses and cars

CO2 emission factors (kg/GJ)

$CO2_{Coal}, CO2_{Oil}, CO2_{Ngas}, CO2_{Waste}$ = CO2 emission factors

CO2 trade price (DKK/t CO2)

$P_{CO2-trade}$: CO2 emission quota price (included in marginal costs)

The Fuel window is part of the Cost section. As shown in the diagram, the cost data of the model are divided into four sets of data: Fuel, Operation, Investment and Additional. The Additional window contains additional investment specification.

An analysis using technical optimisation strategies can be done solely on technical data for the nine input windows described in the previous section. However, if one wants to include either market-economic optimisation or if a feasibility study is conducted, further inputs are required in the “cost” section.

In the guidelines on how to use the EnergyPLAN model, one can learn how to conduct feasibility studies and market exchange studies when cost data input are provided for the model. Such analyses are conducted in exercise 5 and guidelines. Both can be found on www.EnergyPLAN.eu.

Fuel prices are specified as world market prices and domestic handling costs and taxes, if any. The input in the Fuel Cost window is used for two purposes. The one is for the calculation of marginal productions costs, which is done in the Cost Operation window (see below in section 4.11). And the other is to include the fuel costs in the feasibility study at the end of the energy system analysis (see section 8.8)

4.11 Operation Cost

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Frontpage Input Cost Regulation Output Settings

Fuel **Operation** Investment Additional

Variable Operation and Maintenance Cost

District Heating and CHP systems

Boiler	0	DKK/MWh-th
CHP	0	DKK/MWh-e
Heat Pump	0	DKK/MWh-e
Electric heating	0	DKK/MWh-e

Power Plants

Hydro Power	10	DKK/MWh-e
Condensing	0	DKK/MWh-e
Nuclear	0	DKK/MWh-e

Storage

Electrolyser	0	DKK/MWh-e
Pump	0	DKK/MWh-e
Turbine	0	DKK/MWh-e
V2G Discharge *)	0	DKK/MWh-e
Hydro Power Pump	3	DKK/MWh-e

Individual

Boiler	0	DKK/MWh-th
CHP	0	DKK/MWh-e
Heat Pump	0	DKK/MWh-e
Electric heating	0	DKK/MWh-e

*) Total cost of storing defined pr. MWh of electricity production
**) Minimum selling price divided by maximum buying price

Marginal Costs of producing 1 MWh electricity

DistrictHeating	Incr. CHP2 decr. HP2	0	DKK/MWh
	Incr. CHP3 decr. HP3	0	DKK/MWh
	Incr. CHP2 decr. B2	0	DKK/MWh
	Incr. CHP3 decr. B3	0	DKK/MWh
	Incr. B2 decr. HP2	0	DKK/MWh
	Incr. B3 decr. HP3	0	DKK/MWh
	Incr. B2 decr. EB2	0	DKK/MWh
	Incr. B3 decr. EB3	0	DKK/MWh
	incr. CHP2 decr. ELT2	0	DKK/MWh
	incr. CHP3 decr. ELT3	0	DKK/MWh
	incr. B2 decr. ELT2	0	DKK/MWh
	incr. B3 decr. ELT3	0	DKK/MWh
Power Plants	Condensing Power	0	DKK/MWh
	Hydro Power	10	DKK/MWh
	Nuclear	0	DKK/MWh
Individual	Incr. Ngas.CHP decr. B.	0	DKK/MWh
	Incr. Bio.CHP decr. B.	0	DKK/MWh
	Incr. HP decrease EH	0	DKK/MWh

Marginal Costs of storing 1 MWh electricity

		DKK/MWh	Multiplication Factor **)
Individual	Incr. H2.CHP decr. Boiler	0	1,85
Storage	V2G (Electric Vehicle)	0	1,23
	Pump/Turbine (CAES)	0	1,39
	Hydro Pump Storage	11	1,23

Input

Variable Operation Costs (DKK/MWh)

$P_{VOC-Boiler-DH}$, $P_{VOC-CHP-DH}$, $P_{VOC-HP-DH}$, $P_{VOC-EH-DH}$ = Variable operation costs in district heating plants

$P_{VOC-Hydro}$, P_{VOC-PP} , $P_{VOC-Nuclear}$, $P_{VOC-Geothermal}$ = Variable operation costs in power plants

$P_{VOC-Elc}$, $P_{VOC-Pump}$, $P_{VOC-Turbine}$, $P_{VOC-V2G}$, $P_{VOC-Hydro-Pump}$ = Variable operation costs in storage systems

$P_{VOC-Boiler-Indv}$, $P_{VOC-CHP-Indv}$, $P_{VOC-HP-Indv}$, $P_{VOC-EH-Indv}$ = Variable operation costs in individual households

In the Cost Operation window, variable operation and maintenance costs are specified for all units, which are involved in the electricity balancing. Such costs are used for identifying all relevant marginal production costs, which are calculated on the basis of fuel costs, taxes, CO2 costs (specified in the Fuel Cost window) and variable operation costs. Fuel costs consist of international market prices plus local handling costs as shown in the input window below.

For units connected to district heating plants (such as CHP and heat pumps), power stations and individual micro CHP, marginal costs are given in DKK/MWh electricity production/consumption.

For storage units such as hydrogen CHP and pump storage systems, marginal costs are given in a multiplication factor together with an addition factor. Basically, the optimisation criterion is the following:

$$p_{sell} > p_{buy} * f_{MUL} + f_{ADD}$$

In which p_{sell} is the market electricity price when selling (DKK/MWh)

P_{buy} is the market electricity price when buying (DKK/MWh)
 f_{MUL} is the multiplication factor (always bigger than 1), and
 f_{ADD} is the addition factor (DKK/MWh)

The calculation of marginal production prices is based on the fuel specifications in the various input windows. Only fuels, which are specified as variable, are included in the calculation.

4.12 Investment Cost

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Frontpage Input Cost Regulation Output Settings

Fuel Operation Investment Additional

Investment and Fixed Operation and Maintenance Costs

Interest: 0 Percent pro anno

CHP systems	Investment		Period		O. and M.	Total Inv. Costs	Annual Costs (MDKK/year)		Investment	Fixed Opr. and M.
	Unit	MDKK pr. Unit	Years	% of Inv.			MDKK	Investment		
Small CHP units	1000 MW-e	0	0	0	0	0	0	0	0	0
Heat Pump gr. 2	0 MW-e	0	0	0	0	0	0	0	0	0
Heat Storage CHP	20	0	0	0	0	0	0	0	0	0
Large CHP units	1500 MW-e	0	0	0	0	0	0	0	0	0
Heat Pump gr. 3	100 MW-e	0	0	0	0	0	0	0	0	0
Heat Storage Solar	0	0	0	0	0	0	0	0	0	0
Boilers gr. 2 and 3	10000 MW-th	0	0	0	0	0	0	0	0	0
Large Power Plants	2500 MW-e	0	0	0	0	0	0	0	0	0
Wind	1000 MW-e	0	0	0	0	0	0	0	0	0
Wind offshore	0 MW-e	0	0	0	0	0	0	0	0	0
Photo Voltaic	500 MW-e	0	0	0	0	0	0	0	0	0
Wave power	0 MW-e	0	0	0	0	0	0	0	0	0
River of hydro	0 MW-e	0	0	0	0	0	0	0	0	0
Hydro Power	0 MW-e	0	0	0	0	0	0	0	0	0
Hydro Storage	0	0	0	0	0	0	0	0	0	0
Hydro Pump	0 MW-e	0	0	0	0	0	0	0	0	0
Nuclear	0 MW-e	0	0	0	0	0	0	0	0	0
Geothermal	0 MW-e	0	0	0	0	0	0	0	0	0
Electrolyser	0 MW-e	0	0	0	0	0	0	0	0	0
Hydrogen Storage	0	0	0	0	0	0	0	0	0	0
Pump	0 MW-e	0	0	0	0	0	0	0	0	0
Turbine	0 MW-e	0	0	0	0	0	0	0	0	0
Pump Storage	0 MW-e	0	0	0	0	0	0	0	0	0
Indv. boilers	0 MW-th	0	0	0	0	0	0	0	0	0
Indv. CHP	0 MW-e	0	0	0	0	0	0	0	0	0
Indv. Heat Pump	0 MW-e	0	0	0	0	0	0	0	0	0
Indv. Electric heat	6985 MW-e	0	0	0	0	0	0	0	0	0
Indv. Solar thermal	0 TWh/year	0	0	0	0	0	0	0	0	0

Additional various investment costs (see next page)

Investment Sum Annual Costs: 0 (MDKK/year)

Fixed Oper. and M. Sum Annual Costs: 0 (MDKK/year)

Show All

Input

For each component (here shown for wind):

$P_{\text{Unit-Wind}}$ = Pr. unit price

n_{Wind} = lifetime of investment

$P_{\text{FOC-Wind}}$ = Fixed annual operation costs in percentage of total investment

General for all calculations:

i = calculation interest (real interest) for socio-economic evaluation

In the Investment Cost window, the model summarises the input capacity specifications for the production units, and one can add unit prices, lifetimes and fixed operation and maintenance costs. Also one has to enter an interest for the whole calculation. The total investment, I , of each production unit is simply calculated as:

$$I_{\text{Wind}} = C_{\text{Wind}} * P_{\text{Unit-Wind}}$$

The model then calculates the annual costs of each component divided into investment costs and fixed operation and maintenance costs.

The annual costs, $A_{\text{Investment}}$, are calculated as follows:

$$A_{\text{Investment-Wind}} = I_{\text{Wind}} * i / [1 - (1+i)^{-n}]$$

In which

- I_{Wind} are the investment costs found by multiplying the number of units by the cost unit (MDKK per unit). The unit is shown for each component. E.g. the unit for large CHP is MW, and consequently the cost is defined in million DKK/MW.
- n is the lifetime given in years.
- i is the interest

The annual fixed operation costs, A_{FOC} , are calculated as follows:

$$A_{\text{FOC-Wind}} = P_{\text{FOC-Wind}} * I_{\text{Wind}}$$

In which

- P_{FOC} is the annual fixed operation and maintenance costs given in percentage of the investment cost.

4.13 Regulation

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Frontpage | Input | Cost | Regulation | Output | Settings

Regulation:

Chose Optimisation Strategy:

1 Meeting heat demands

Electric grid stabilisation requierments:

Minimum grid stabilisation production share

Stabilisation share of CHP2

Minimum CHP in gr. 3:

Heat Pump Maximum load:

External Electricity Market Definition

Price distribution Hour_nordpool.txt

Addition factor DKK/MWh

Multiplication factor

Resulting average price : 227 DKK/MWh

Critical Electricity Excess Production (CEEP)

Critical Electricity Excess Production (CEEP) regulation: Write number:

1 : Reducing wind production
 2 : Reducing CHP in gr.2 by replaing with boiler
 3 : Reducing CHP in gr.3 by replaing with boiler
 4 : Replacing boiler with electric heating in gr.2
 5 : Replacing boiler with electric heating in gr.3
 6 : Reducing photo voltaic production
 7 : Reducing power plant in combination with wind and photo voltaic production

External Electricity Market response to import/export

Price elasticity DKK/MWh pr. MW

Basic price level for price elasticity DKK/MWh

Transmission line capacity

Maximum imp./exp. cap: MW

Input

Electric grid stabilisation requirements:

$Stab_{Total}$ = Demand for grid-stabilising units in percentage of total electricity production

$Stab_{CHP2}$ = Share of CHP2 units which can provide grid stabilisation

$C_{CHP3-Min}$ = Minimum production on CHP units in DH group 3

$LIMIT_{HP}$ = Maximum heat production form heat pumps

External Electricity Market Definition:

$p_{Market-input}$ = Input hour by hour, external market electricity price

Fac_{Mul} = Multiplication factor

Fac_{Add} = Addition factor

Fac_{Depend} = Dependency factor (price elasticity)

p_o = Basic price level for price elasticity

Transmission line capacity:

$C_{Imp/exp}$ = Import/export transmission line capacity

In the Regulation window, one can specify the wanted regulations strategy together with grid stabilisation requirements and relations to external electricity markets.

4.13.1 External electricity market definition

The market price on the external electricity market is defined by the following input:

- An hour by hour distribution of prices (chosen from the Library)
- Fac_{Mul} = Multiplication factor
- Fac_{Add} = Addition factor
- Fac_{Depend} = Dependency factor (price elasticity)
- p_o = Basic price level for price elasticity

For the economic optimisation, the market prices, p_{Market} , are found from the specified hour by hour price distribution ($p_{\text{Market-input}}$) when modified in the following way:

$$p_{\text{Market}} = p_{\text{Market-input}} * \text{Fac}_{\text{Mul}} + \text{Fac}_{\text{Add}}$$

The resulting average market price after influence by the multiplication and addition factors is calculated simultaneously and shown in the window.

In the economic optimisation strategy and in the calculation of income from exchange, the market price is further influenced by the price elasticity, as described in sections 7.1, 7.10 and 8.8.2.

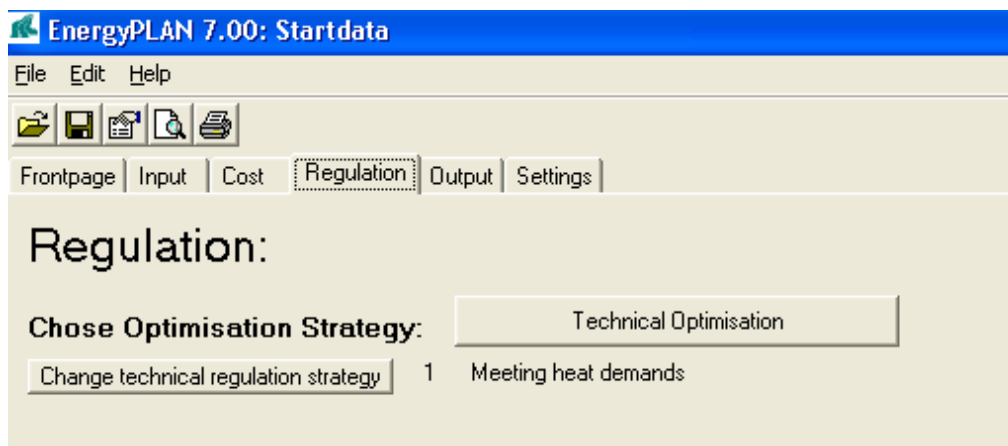
4.13.2 Choice of regulations strategy

The choice of regulation strategy is done by activating the upper button. Here, one can choose between Technical Optimisation, as described in chapter 6, or Market-Economic optimisation, as described in chapter 7.



If technical optimisation is selected, then one must choose between the following 4 technical optimisation strategies, all explained in chapter 6:

1. Balancing heat demands
2. Balancing both heat and electricity demands
3. Balancing both heat and electricity demands (Reducing CHP also when needed partly for grid stabilisation)
4. Balancing heat demands using triple tariff



4.13.3 Choice of Critical Excess Electricity Production (CEEP) Regulation Strategy

The electric connection to external electricity markets is limited by the definition of the capacity of the transmission lines. Based on such limitation, the model identifies Critical Excess Electricity Production (CEEP) as the export which exceeds the transmission line capacity. Such production is not allowed in real life, since this will cause a breakdown in the electricity supply.

However, the model allows CEEP in order to be able to calculate the magnitude as a consequence of different regulation strategies, or one can ask the model to avoid CEEP.

Seven options to remove critical excess electricity production can be activated:

- 1: Reducing RES1 and RES2
- 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.
- 6: Reducing RES4 and RES5
- 7: Reducing power plant production in combination with RES1, RES2, RES3 and RES4

The seven possibilities are activated in a priority. If for instance "CEEP regulation" is stated as 23547, critical excess production will be removed first by replacing CHP in groups 2 and 3, then by electric heating and, in the end, by decreasing electricity production from RES1-RES4 together with power plants. For "CEEP regulation" = 51, excess production is removed first by increasing electric heating only in group 3 and then by stopping RES1 and RES2. All 7 options can be activated in all possible combinations.

In chapter 8, it is explained how the reduction of CEEP is calculated and what the specific difference is between the options.

4.13.4 Grid Stabilisation Restrictions

The model calculates hour by hour and basically assumes that all production units can change production from one hour to another. However, especially large steam turbine CHP or extraction plants have difficulties in going below a certain technical minimum, typically 20% of max capacity. Therefore, one can specify a minimum CHP3 production.

Apart from such minimum production, one can specify limitations in the operation in order to assure grid stability. A certain percentage (30 percent is recommended) of the total electricity production must come from grid-stabilising units. CHP in group 3 and large power plants including hydro, geothermal and nuclear power are assumed to have such stabilising abilities. Therefore, one can specify to which extent small CHPs in group 2 and RES units can provide grid stabilisation.

5. Initial analyses not involving electricity balancing

The model starts by making a number of initial calculations on the input data. Various electricity and heat demands are found simply by distributing the annual demands according to the internal hour by hour distributions.

5.1 Fixed import/export of electricity

The fixed import/export demand is meant to describe exchanges with external electricity markets additional to the one, which is active in the model. Input is annual electricity demand, D_{EX} , together with hourly distribution, δ_{EX} . The hour by hour values, d_{EX} , are calculated as follows:

$$d_{EX} = D_{EX} * \delta_{EX} / \sum \delta_{EX}$$

5.2 District heating demands incl. heat demands from absorption cooling

District heating demands in the three district heating groups, including the heating demand for absorption cooling in the various groups are calculated in the following way.

For all three district heating groups, the demand is defined by an annual heat demand, H_{DH} , together with the hourly distribution, δ_{DH} . The same goes for heat demands for absorption cooling in the various district heating groups: H_{Cool} and δ_{Cool} . The hour by hour values, h_{DH} , are calculated as follows:

$$h_{DH} = H_{DH} * \delta_{DH} / \sum \delta_{DH} + H_{Cool} * \delta_{Cool} / \sum \delta_{Cool}$$

5.3 District heating and electricity productions from Industry and Waste

District heating and electricity production from Industrial CHP are defined for each of the three district heating groups by the annual heat and electricity productions, $Q_{Industry-DH}$ and $E_{Industry-DH}$, together with the hourly distribution, $\delta_{Industry-DH}$:

$$q_{Industry-DH} = Q_{Industry-DH} * \delta_{Industry-DH} / \sum \delta_{Industry-DH}$$

$$e_{Industry-DH} = E_{Industry-DH} * \delta_{Industry-DH} / \sum \delta_{Industry-DH}$$

District heating and electricity production from Waste are calculated in the same way:

$$q_W = Q_W * \delta_W / \sum \delta_W$$

$$e_W = E_W * \delta_W / \sum \delta_W$$

Both Industry and Waste are calculated separately for all three district heating groups.

5.4 Fixed Boiler production subtracted from the district heating demand

The CHP units of each district heating group are modelled by one average production unit with average efficiencies. Therefore, the model can not include simulation of situations in which the units of one system are not operating because of maintenance or breakdowns. However, one can compensate for this problem by specifying a certain percentage of the district heating demand, which has to be supplied from the boiler, the so-called “fixed boiler share”, $FixedPercent_B$. Studies indicate that approximately 2 per cent of fixed boiler share” will compensate properly. The compensation is

calculated as a percentage of the annual district heating demand in groups 2 and 3 and afterwards subtracted from the demand. Here shown for district heating group 2:

$$q_{\text{FixedBoiler2}} = H_{\text{DH2}} * \text{FixedPercent}_{\text{B2}} / 8784$$

$$h_{\text{DH2}} = h_{\text{DH2}} - q_{\text{FixedBoiler2}}$$

Later on (see section 8.1), the production is added to the boiler production:

$$q_{\text{B2}} = q_{\text{B2}} + q_{\text{FixedBoiler2}}$$

The same calculation is done for district heating group 3.

5.5 Boiler production in district heating group 1

In group I, heat for district heating is produced by:

1. Solar Thermal: q_{solar1}
2. Industrial CHP (CSHP): $q_{\text{Industry-DH1}}$
3. Heat production from waste fuel: q_{W1}
4. District heating plants with boilers: q_{B1}

The productions from solar thermal, CSHP and waste are calculated for each hour from the input data and the respective distribution sets. The production from the boiler is found as the difference between demands and solar/CSHP productions:

$$q_{\text{B1}} = h_{\text{DH1}} - q_{\text{solar}} - q_{\text{Industry-DH1}} - q_{\text{W1}}$$

$$\mathbf{If} \quad q_{\text{B1}} < 0 \quad \mathbf{then} \quad q_{\text{B1}} = 0$$

6. Technical Energy System Analysis

The following chapter describes the technical energy systems analysis of step 3A in the overview.

6.1 Condensing power and import/export including CEEP and EEEP

The calculation of condensing power and import/export including CEEP and EEEP (Critical and Exportable Excess Electricity Production) are calculated continuously more or less after each of the following sequences (sections 6.2 – 6.9) in the technical energy system analysis procedure.

The demand is calculated as the sum of the following demands:

$$d_{\text{Total}} = d_E + d_{\text{EX}} + d_{\text{FX}} + d_{\text{Cool}} + d_{\text{Elc}} + d_{\text{BEV}} + d_{\text{V2G}} + d_{\text{I-HP-total}} + d_{\text{I-EH}} + d_{\text{HP2}} + d_{\text{HP3}} + d_{\text{Pump}} + d_{\text{HydroPump}}$$

$$\text{in which } d_{\text{FX}} = d_{\text{FXDay}} + d_{\text{FXWeek}} + d_{\text{FX4Week}}$$

$$\text{and } d_{\text{Elc}} = d_{\text{Elc2}} + d_{\text{Elc3}} + d_{\text{ElcT}} + d_{\text{ElcM}}$$

The production except from the condensing power plants is calculated as the sum of the following:

$$e_{\text{Total}} = e_{\text{Res}} + e_{\text{M-CHP}} + e_{\text{Hydro}} + e_{\text{Nuclear}} + e_{\text{V2G}} + e_{\text{W}} + e_{\text{CSHP}} + e_{\text{CHP2}} + e_{\text{CHP3}} + e_{\text{Turbine}}$$

$$\text{in which } e_{\text{Res}} = e_{\text{Res1}} + e_{\text{Res2}} + e_{\text{Res3}} + e_{\text{Res4}}$$

$$\text{and } e_{\text{M-CHP}} = e_{\text{M-h2CHP}} + e_{\text{M-NgasCHP}} + e_{\text{M-BioCHP}}$$

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

A. The difference between demand and production:

$$e_{\text{PP}} = d_{\text{Total}} - e_{\text{Total}}$$

B. The minimum production needed in order to fulfil the requirement of stabilising the grid:

$$e_{\text{PP}} = (e_{\text{Total}} * \text{Stab}_{\text{total}} - e_{\text{CHP2}} * \text{Stab}_{\text{CHP2}} - e_{\text{Res1}} * \text{Stab}_{\text{Res1}} - e_{\text{Res2}} * \text{Stab}_{\text{Res2}} - e_{\text{Res3}} * \text{Stab}_{\text{Res3}} - e_{\text{Res4}} * \text{Stab}_{\text{Res4}} - e_{\text{CHP3}} - e_{\text{Nuclear}} - e_{\text{Hydro}} - e_{\text{V2G}}) / (1 - \text{Stab}_{\text{total}})$$

The needed share of power plants with stabilising ability of the total production minus the share of the other units, which are assumed to have stabilising ability.

In case e_{PP} exceeds the specified maximum value C_p , the necessary quantity of electricity production is imported.

The import and export of electricity can now be calculated as:

$$\begin{aligned} \text{If } (e_{\text{Total}} + e_{\text{PP}} - d_{\text{Total}} < 0) \text{ then } e_{\text{Import}} &= e_{\text{Total}} + e_{\text{PP}} - d_{\text{Total}} \quad \text{or else } e_{\text{Import}} = 0 \\ \text{If } (e_{\text{Total}} + e_{\text{PP}} - d_{\text{Total}} > 0) \text{ then } e_{\text{Export}} &= e_{\text{Total}} + e_{\text{PP}} - d_{\text{Total}} \quad \text{or else } e_{\text{Export}} = 0 \end{aligned}$$

The export is divided into two categories: 1) Critical Excess Electricity Production, e_{CEEP} and 2) Exportable Excess Electricity Production, e_{EEEP} . Critical excess electricity production appears when the export exceeds the maximum capacities of the grid connections abroad:

If $e_{\text{Export}} > C_{\text{Transmission}}$
then $e_{\text{CEEP}} = e_{\text{Export}} - C_{\text{Transmission}}$ **and** $e_{\text{EEEE}} = C_{\text{Transmission}}$
or else $e_{\text{CEEP}} = 0$ **and** $e_{\text{EEEE}} = e_{\text{Export}}$

6.2 CHP, Heat Pumps and boilers in groups 2 and 3 (regulation 1 or 4)

Based on the modified “hour by hour distributions” described above and the rest of the input data, the model calculates electricity and heat productions depending on the regulation strategy chosen.

6.2.1 Regulation strategy 1: Meeting heat demand

In this strategy, all heat producing units are producing solely according to the heat demand. For district heating groups 2 and 3, the units are given priority on an hourly basis according to the following sequence:

- | | |
|-------------------------------------|---------------------------|
| 1. Solar Thermal: | q_{solar2} |
| 2. Industrial CHP (CSHP): | $q_{\text{Industry-DH2}}$ |
| 3. Heat production from waste fuel: | q_{W2} |
| 4. Heat plant CHP: | q_{CHP2} |
| 5. Heat pumps: | q_{HP2} |
| 6. Peak load boilers: | q_{B2} |

The productions from solar thermal, CSHP and waste are calculated for each hour from the input data and the respective distribution sets. The heat productions from CHP and heat pumps are found as the difference between demands and solar/CSHP productions:

$$q_{\text{CHP2}} = h_{\text{DH2}} - q_{\text{solar2}} - q_{\text{Industry-DH2}} - q_{\text{W2}}$$

$$\text{If } q_{\text{CHP2}} > T_{\text{CHP2}} \text{ then } q_{\text{CHP2}} = T_{\text{CHP2}}$$

$$q_{\text{HP2}} = h_{\text{DH2}} - q_{\text{solar2}} - q_{\text{Industry-DH2}} - q_{\text{W2}} - q_{\text{CHP2}}$$

$$\text{If } q_{\text{HP2}} > T_{\text{HP2}} \text{ then } q_{\text{HP2}} = T_{\text{HP2}}$$

$$\text{If } q_{\text{HP2}} > h_{\text{DH2}} * \text{SHARE}_{\text{HP2}} \text{ then } q_{\text{HP2}} = h_{\text{DH2}} * \text{SHARE}_{\text{HP2}}$$

For the heat plant CHPs and the heat pumps, the calculation respects the maximum capacity as well as the maximum share of heat pumps compared to the total heat demand, $\text{SHARE}_{\text{HP2}}$. This limitation corresponds to the fact that heat pumps should be used for the production of low temperature heat only. The peak load boiler supplies the remaining demand:

$$q_{\text{B2}} = h_{\text{DH2}} - q_{\text{solar2}} - q_{\text{Industry-DH2}} - q_{\text{W2}} - q_{\text{CHP2}} - q_{\text{HP2}}$$

$$\text{If } q_{\text{B2}} > T_{\text{B2}} \text{ then } q_{\text{B2}} = T_{\text{B2}}$$

The model also controls that no heat production becomes negative and the resulting heat balance is calculated and shown as a result. Due to limitations in capacities or excess productions from solar thermal or industry/waste such result may show imbalances.

6.2.2 Regulation strategy 4: Meeting the triple tariff

Regulation strategy 4 is the same as strategy 1 apart from one factor.

In regulation strategy 4, the CHP units in group 2 meet the Danish triple tariff instead of meeting the heat demand.

The electricity production from CHP units in group 2 is 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 the rest of the time.

Regulation strategies 1 and 4 are the same in the sense that in neither of the cases, the CHPs adjust their productions according to the fluctuations in the wind power.

6.3 Flexible electricity demand (including dump charge BEV)

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 3). Or other external input files can be created. The electricity demand is distributed according to the specified distribution. Moreover, one can add a fixed import/export demand as described for the “input electricity heating” window in section 4.1.

Any new demands created by the use of electricity for transport (batteries and/or hydrogen) or by other purposes can be specified in the input transportation window (described in section 4.8). Electricity for transport can be made flexible in two ways. One comprises the smart charge and V2G possibilities in the transportation window (section 4.8) and the other is to specify a flexible demand. The same routines can be used for defining a certain percentage of the demand as flexible demand. This allows for an analysis of the consequences of introducing flexible demands for cooling etc. within industries and/or households.

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

1. Demand following a specified distribution (typically battery cars being charged during the night). Section 4.8.
2. Demand freely distributed over a 24-hour period according to the actual electricity balance. (Similar to the above, but with the added possibility of concentrating the demand at the actual peak hours for e.g. wind production - requires a method of communicating this knowledge to the consumers). Section 4.1.
3. 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 hydrogen-operated vehicles). Section 4.1.
4. Demand which can be distributed freely over a four-week period (similar to the above - relevant for hydrogen-operated vehicles. The optimal distribution of demand for a period of this length requires a long-term prognosis for the electricity balance to be transmitted to the consumers. Since this prognosis is partly based on a weather prognosis, this is hardly possible today, as the prognosis for a four-week period at present is not sufficiently reliable). Section 4.1.

For the categories 2., 3. and 4., the demands are distributed within the given intervals one by one according to an evaluation of the balance between “fixed” electricity productions and demands. The calculation of productions and demands is done in accordance with the description in section 6.1. However, only productions and demands from units calculated up to now (i.e. steps 1 and 2 and

section 6.2) are included; i.e. Nuclear and all RES, CHPs and Heat Pumps based on regulation 1 or 4 including individual units. Hydro power and micro CHP are based on the initial estimate not including the regulation described later in this chapter. Moreover, electricity productions for dump charge BEV are included. Productions and demands from more flexible units such as electricity storage systems and electrolyzers are not included.

The distribution of demands within the interval is made in order to provide 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_{FX} (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 as flexible in the same way as the transport demands of categories 2, 3, and 4. 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 maximum capacity must be stated. Please 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 diagrams 6.1 and 6.2, an example of how flexible demand reduces differences in the balance between the supply from CHP and renewable energy and the demand is shown.

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 6.1, it is illustrated how this situation in a three-day period in January has a continuous CHP production of app. 3200 MW, and on top of this, a wind production increasing the total production to between app. 3500 and 5000 MW.

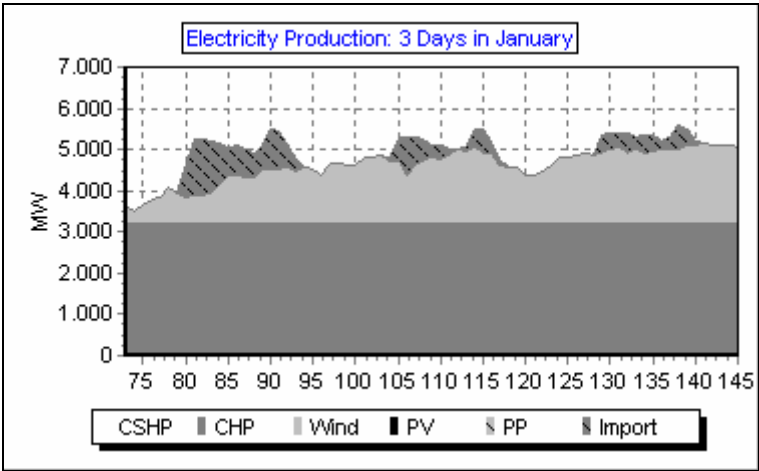


Diagram 6.1: Electricity Production from CHP, Wind and Import, 3 Days in January.

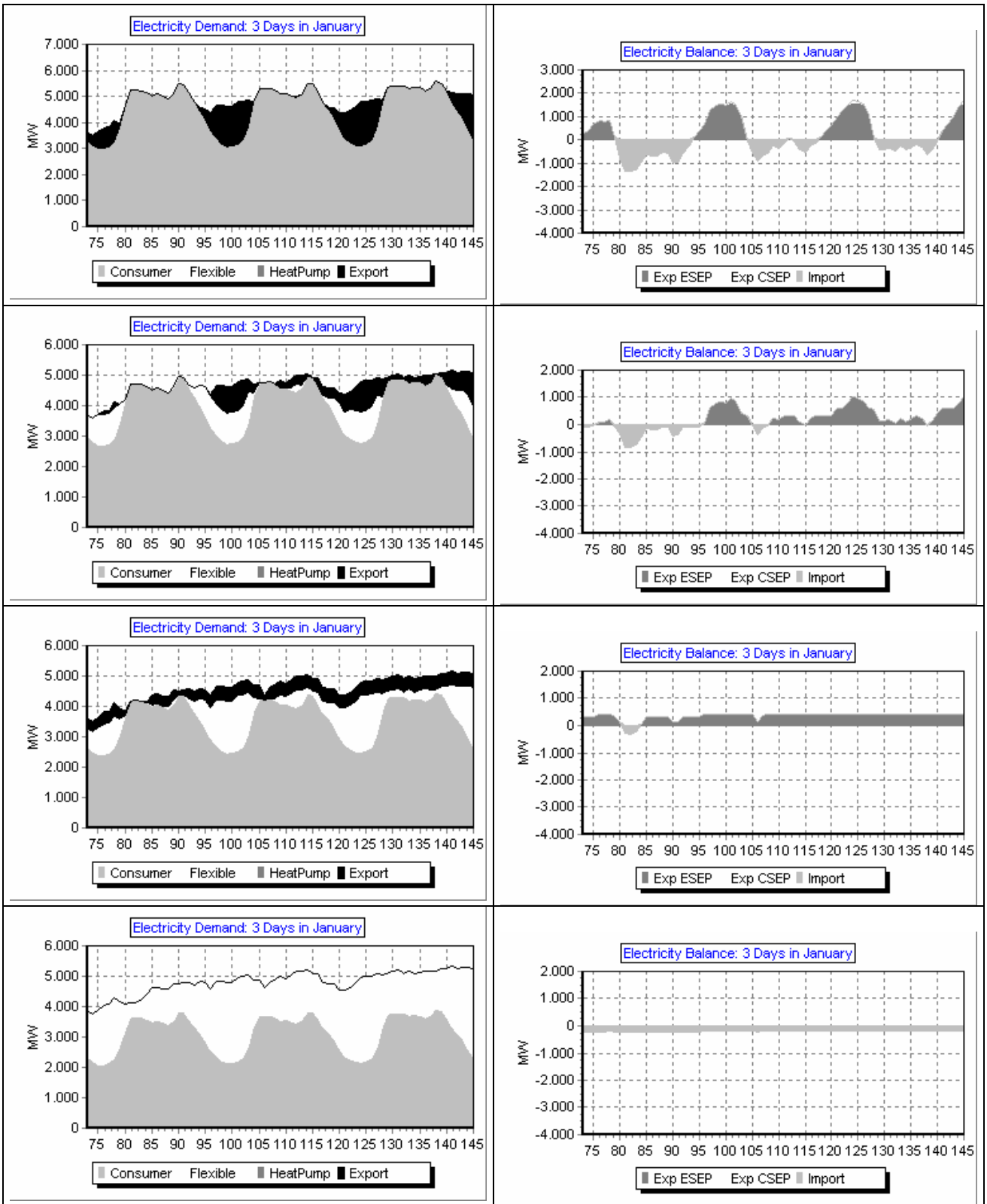


Diagram 6.2: Example of flexible demand

In the upper left corner of diagram 6.2, the demand is shown (in the case of no flexible demand); and to the right, the resulting difference in the balance between supply and demand is shown. The latter diagram is found simply by subtracting the demand and the supply from diagram 6.1. It can be seen how an excess production takes place during night hours and there is a lack of supply during day hours, fluctuating along with the variations in the wind production.

At the next three levels of diagram 6.2, more and more demand has been changed into flexible demand in the input. At the second level, 10 per cent is made flexible within a day. At the next level, an additional 10 per cent is made flexible within a week. And in the last picture, an additional 10 per cent is made flexible within a four-week period. It can be seen how such flexibility is able to continuously improve the balance between supply and demand.

6.4 CHP, Heat Pumps and boilers in groups 2 and 3 (regulation 2 or 3)

If technical regulation strategy 2 or 3 is chosen, the following calculations are done, which will then replace the calculations of section 6.2 (strategy 1 or 4).

6.4.2 Regulation strategy 2: Meeting both heat and electricity demands

In this section, the export of electricity is minimised mainly by the use of heat pumps at CHP plants. This will simultaneously increase electricity demand and decrease electricity production 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 **electricity production by CHP**, 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 (including waste) and the solar thermal production. Within these limits it is determined as the larger of the results of the following two considerations:

- A. The capacity which can ensure stability of the grid together with a possible stabilising effect of the RES units but without relying on any effect from condensation plants:

$$e_{CHP,II,A} = (e_{Total} * Stab_{total} - e_{RES1} * Stab_{RES1} - e_{RES2} * Stab_{RES2} - e_{RES3} * Stab_{RES3} - e_{RES4} * Stab_{RES4} - e_{CHP3} - e_{Nuclear} - e_{Hydro}) / Stab_{CHP2}$$

- B. 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, $e_{Export,I}$. The reduction needed 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, $Share_{HP}$). If this is not the case, the reduction in heat production caused by the reduction in electricity production can be balanced by an increase in the heat produced by the heat pumps. This will also reduce the electricity export. As a result, the necessary reduction is reduced by a factor

$$1 + T_{CHP}/C_{CHP} * C_{HP}/T_{HP}$$

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, $e_{Export,I}$.

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

a. Reduction of CHP plus increase of heat pump production:

$$e_{HPmax} = \min(C_{HP} ; h_{DH} * Share_{HP})$$

$$e_{CHP,red,a} = \min (e_{Export,I} / (1 + T_{CHP}/C_{CHP} * C_{HP}/T_{HP}) ; (e_{HPmax} - e_{HP}) * T_{HP}/C_{HP} * C_{CHP}/T_{CHP})$$

$$e_{HP,inc,a} = e_{CHP,red,a} * T_{CHP}/C_{CHP} * C_{HP}/Y_{HP}$$

b. A possible further reduction of CHP only:

$$e_{CHP,red,b} = e_{Export,I} - e_{CHP,red,a} - e_{HP,inc,a}$$

$$e_{CHP,II,B} = e_{CHP,I} - e_{CHP,red,a} - e_{CHP,red,b}$$

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.

6.4.2 Regulation strategy 3: Meeting both heat and electricity demands and reducing CHP also when it is partly needed for reasons of stabilisation (replacing by PP).

Regulation strategy 3 is the same as strategy 2 apart from one factor.

In strategy 2, CHP will not be reduced (and the heat production replaced by heat pumps), if CHP units are needed for reasons of stabilisation.

Meanwhile, in some situations (when the CHP stabilisation factor is below 100 per cent), excess 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 3, CHP units are reduced even when stabilisation demands call for replacement with PP units.

The choice between strategy 2 and 3 is a choice between better efficiency in the system and less excess production.

6.5 Hydro power

Hydro Power Units are defined by the following inputs:

C_{Hydro} : The capacity of the Hydro Power Electricity Generator in MW

μ_{Hydro} : The efficiency of the Hydro Power station defined as the conversion factor from energy in the storage to electricity production from the generator.

S_{Hydro} : The capacity of the Hydro Power storage in GWh

W_{Hydro} : The amount of energy connected to the water supplied to the storage in TWh/year

δW_{Hydro} : The distribution of the energy/water supply in 8784 hour values

Additional input options are:

$\mu_{\text{Hydro-PUMP}}$: The efficiency of running the Generator reversibly as a Pump, defined as the conversion factor from electricity consumption to energy in the storage

$C_{\text{Hydro-PUMP}}$: The capacity of the Hydro Power Pump in MW

$S_{\text{Hydro-PUMP}}$: The capacity of the lower water storage in GWh

The Hydro Power station is subject to the condition that it will always be involved in the task of maintaining grid stability.

The unit is integrated in the regulation of the total system in the following way:

Initially (described in section 4.3.2), the average hour by hour production is calculated based on the water supply to the water reservoirs, which is then modified in order to maximise the potential production when limitations in storage and generator capacities are taken into consideration.

To correct the calculation from errors due to differences in the storage content between the beginning and the end of the calculation period, the calculation seeks to identify a solution in which the storage content at the end is the same as at the beginning. Initially, the storage content is defined as 50% of the storage capacity. After the first calculation, a new initial content is defined as the resulting content at the end of the former calculation.

How the input is calculated can be illustrated by an example with the following inputs:

C_{Hydro} : 400 MW

μ_{Hydro} : 0.8.

S_{Hydro} : 1000 GWh

W_{Hydro} : 2.5 TWh/year

δW_{Hydro} : Distribution as shown in the diagram

In such case, the storage and the generator capacity set no limits to the system and the resulting hydro power production is equal to the average production of 228 MW, as shown in diagrams 6.3 and 6.4 together with the storage content (in GWh). The annual production becomes 2.00 TWh/year (equal to $2.5 * 0.8$). The initial and the final storage contents are identified to be 598 GWh.

However, if one introduces a limitation to the storage capacity, so that the total water input cannot be utilised during a year (e.g. a storage capacity of 500 GWh), the solution shown in diagram 6.5 will be applied.

As one can see, the starting point is the average production of 228 MW. During summer and autumn, when the storage is filled and the water supply is higher than what is needed for average production, the production of the power plant is increased up to the capacity of the generator. Consequently, the storage is not filled when the water supply is low during spring and the production is decreased accordingly. However, in this case, losses in the storage cannot be avoided and the annual production is limited to 1.88 TWh/year and not the potential 2.00 TWh/year.

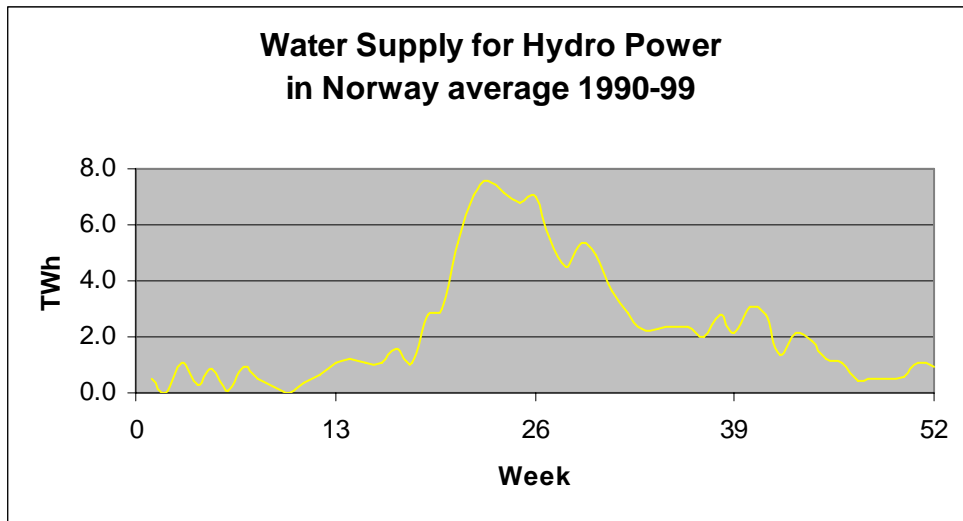


Diagram 6.3: Water supply to the Hydro Power System

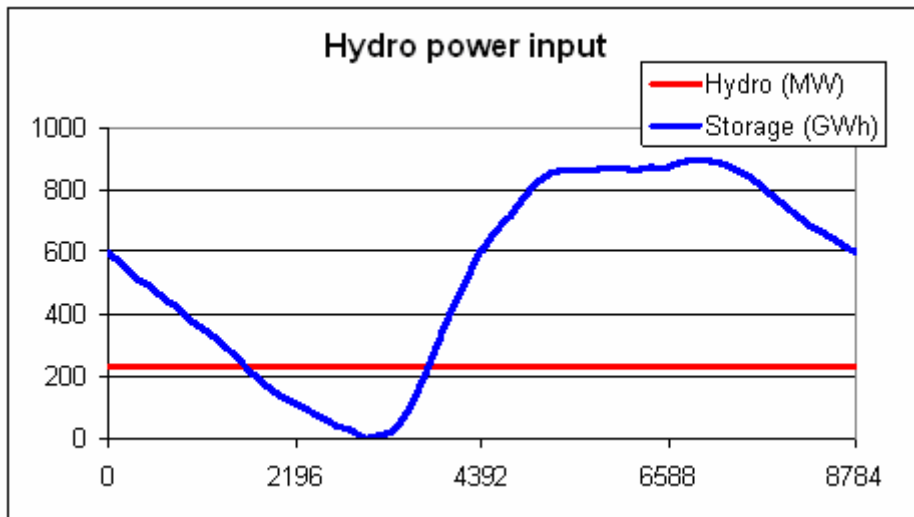


Diagram 6.4: Hydro power output with no limitations in water storage capacity

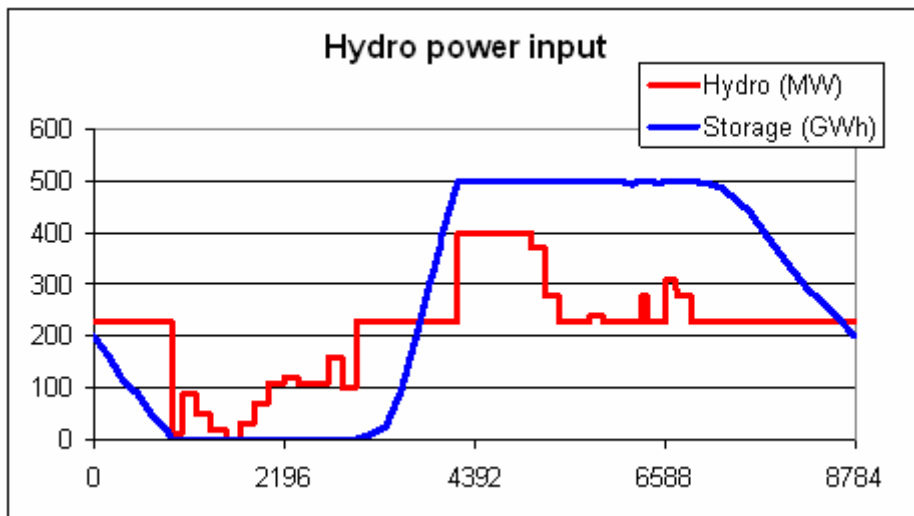


Diagram 6.5: Hydro power output with limitations in water storage capacity

If the capacity of the generator is increased to 700 MW, the solution shown in diagram 6.6 is found in which the system will produce the fully 2.00 TWh/year. If, on the other hand, the capacity is decreased to 300 MW, the annual production will be only 1.79 TWh/year.

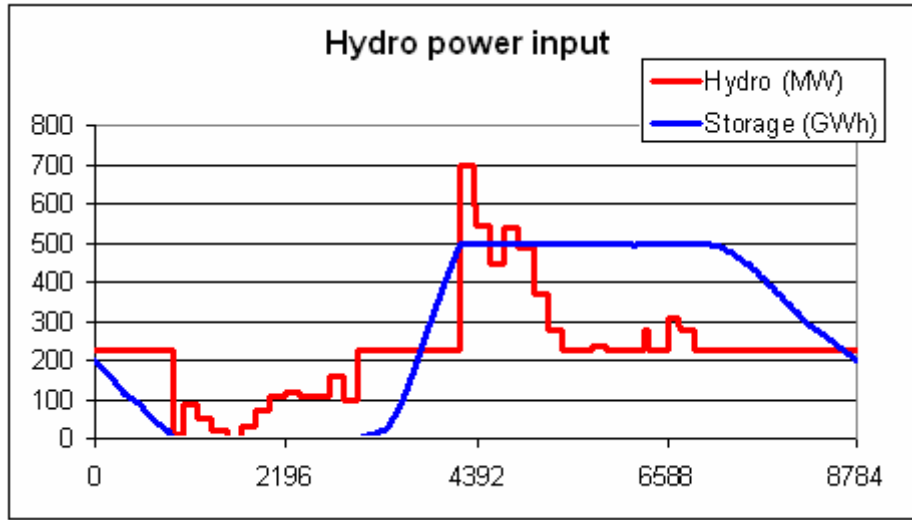


Diagram 6.6: Hydro power output with limitations in water storage and generator capacities

The resulting annual hydro input production is shown simultaneously in the input window in which the input data are specified.

In the potential calculation of flexible demand, the baseline hydro power production is subtracted from the various demands (consumers, fixed import/export, heat pumps and transportation) before the distribution of the flexible demand is determined as described in section 6.3. And in all technical regulation strategies 1, 2, 3 and 4, the above baseline hydro power production is included when the power production from the rest of the units is determined.

Afterwards the condensing power and import/export are calculated again in accordance with section 6.1, and the hydro power is then used for replacing the condensing units and decreasing first CEEP and secondly EEEP in the following way:

First, the potential of replacing the condensing power plant ($e_{\text{Hydro-Inc}}$) is determined as the minimum value of either the production of the condensing unit or the difference between hydro power capacity and hydro power production.

$$e_{\text{Hydro-Inc}} = \text{MIN} (e_{\text{PP}} , (C_{\text{Hydro}} - e_{\text{Hydro}}))$$

The hydro production, e_{Hydro} , is defined as the production found in the initial calculation of section 4.3.2 as illustrated above.

The potential of decreasing hydro power in the case of CEEP ($e_{\text{Hydro-Dec-CEEP}}$) is determined as the minimum value of either the CEEP or the hydro power production. At the same time, the potential is limited by the fact that the hydro power plant potentially forms part of grid stabilisation:

$$e_{\text{Hydro-Dec-CEEP}} = \text{MIN} (e_{\text{CEEP}} , e_{\text{Hydro}})$$

$$e_{\text{Hydro-Dec-CEEP}} \leq e_{\text{Hydro}} - e_{\text{Hydro-Min-Grid-Stab}}$$

In the case of reversal hydro power, i.e. a pump and lower water storage, the potential of decreasing CEEP further ($e_{\text{Hydro-Pump-Dec-CEEP}}$) is determined as the minimum value of the CEEP (minus the share that is already occupied), the pump capacity, or the content of the lower water storage, $S_{\text{Hydro-PUMP}}$:

$$e_{\text{Hydro-Pump-Dec-CEEP}} = \text{MIN} [(e_{\text{CEEP}} - e_{\text{Hydro-Dec-CEEP}}), C_{\text{Hydro-PUMP}}, S_{\text{Hydro-PUMP}} / \mu_{\text{Hydro-PUMP}}]$$

In the same way, the potential of decreasing hydro power in the case of EEEP ($e_{\text{Hydro-DEC-EEEE}}$) is found.

Knowing the potentials of increasing and decreasing the hydro power production, a balance is found in which the annual hydro power production is maintained. The reduction of CEEP is given priority over the reduction in EEEP.

$$\Sigma e_{\text{Hydro-Inc}} = \Sigma e_{\text{Hydro-Dec-CEEP}} + \Sigma e_{\text{Hydro-Dec-EEEE}}$$

Similar to the previous modelling of the hydro power input, the programme again calculates the hour by hour modelling of the system including the fluctuations in the storage content. The hydro power production (e_{Hydro}) is modified in accordance with the generator capacity, the distribution of the water supply and the storage capacity in the following way:

$$\text{Hydro-storage-content} = \text{Hydro-storage content} + w_{\text{Hydro}}$$

$$e_{\text{Hydro}} = e_{\text{Hydro}} + e_{\text{Hydro-Inc}} - e_{\text{Hydro-Dec-CEEP}} - e_{\text{Hydro-Dec-EEEE}}$$

$$e_{\text{Hydro-Input}} \leq (\text{Hydro-storage-content} - S_{\text{Hydro}}) * \mu_{\text{Hydro}}$$

$$e_{\text{Hydro-Input}} \leq C_{\text{Hydro}}$$

Differences in the storage content at the beginning and at the end of the calculation period may cause errors in the calculations. To correct these errors, the above calculation seeks to identify a solution in which the storage content at the end is the same as at the beginning. Initially, the storage content is defined as 50% of the storage capacity. After the first calculation, a new initial content is defined as the resulting content at the end of the former calculation.

How the input is calculated can be illustrated by the example in diagram 6.7. The upper diagram shows the electricity production for a week in a system with a high share of both CHP and wind power. The system has a high excess electricity production (CEEP).

The next diagram shows the influence of the hydro input (before the hydro regulation). It can be seen how the hydro power automatically replaces the power plant (PP) in the situations in which the PP produces in order to secure grid stability. However, in other situations, the hydro power also adds to the problem of excess production.

In the third diagram, the hydro power is part of the regulation and it can be seen how the hydro power plant is used for replacing the condensing plant and reducing the excess production.

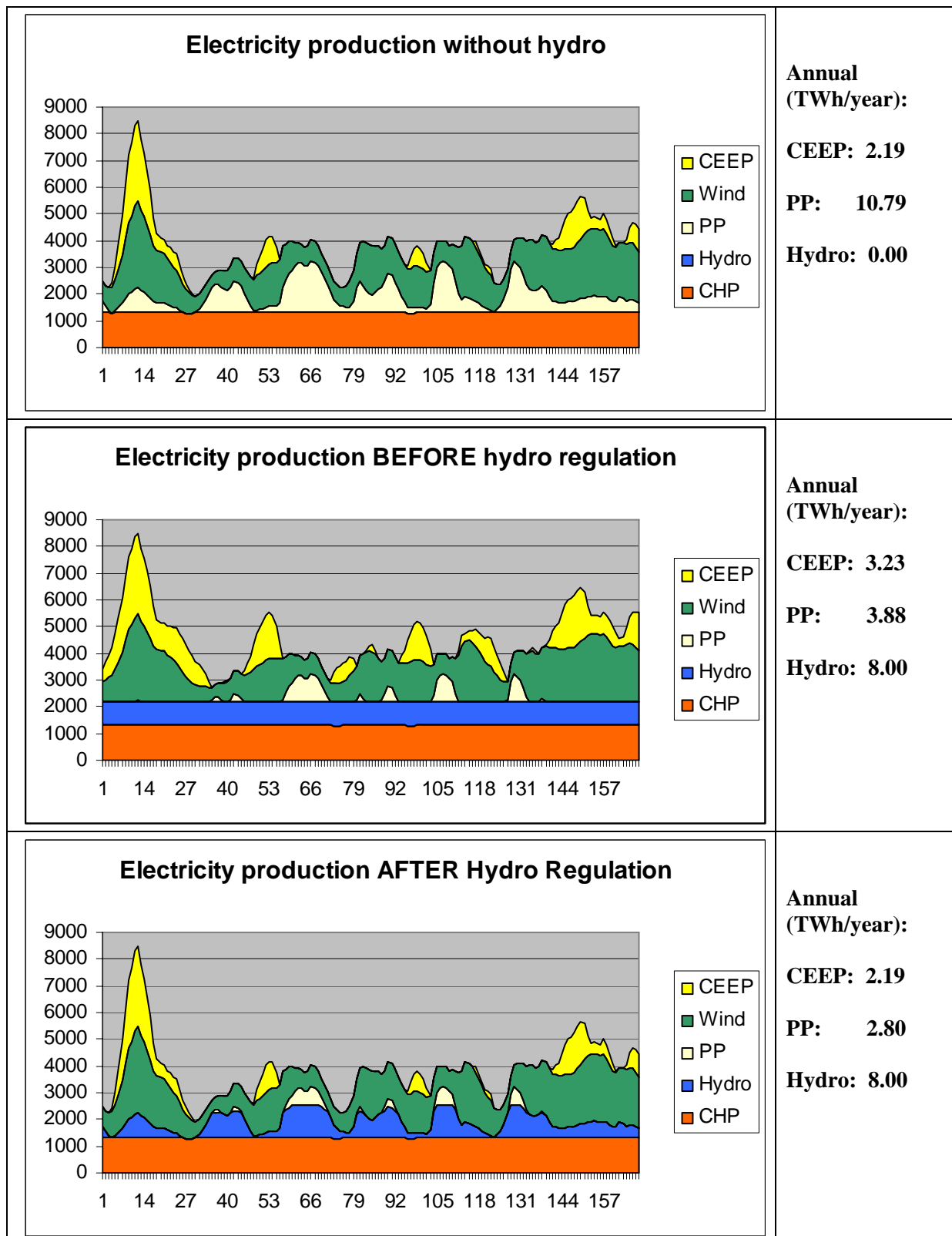


Diagram 6.7: Hydro power is regulated to decrease excess and condensing power productions.

6.6 Individual CHP and Heat Pump systems

The calculations of individual CHP and Heat Pumps systems are based on the initial calculations of section 4.6. If heat storage capacity is specified then the following moderation will be carried out and replace the previous productions.

6.6.1 CHP systems

Heat production and the use of the heat storage give priority to solar thermal, which is calculated as the maximum value of either solar thermal production or heat demand plus available room in the heat storage:

$$q_{\text{Solar-M-H2CHP}} = \text{Max} [q_{\text{Solar-M-H2CHP}}, h_{\text{M-H2CHP}} + (S_{\text{Solar-M-H2CHP}} - S_{\text{Solar-M-H2CHP}})]$$

In case of CEEP

If the solar production is lower than the heat demand and CEEP is positive then the heat demand will be supplied by the heat storage if possible. Only in the case that this can not be done, the CHP unit will be operated. Consequently, the CHP heat production is calculated as follows:

$$q_{\text{M-H2CHP}} = \text{Max} [0, (h_{\text{M-H2CHP}} - S_{\text{Solar-M-H2CHP}} - q_{\text{Solar-M-H2CHP}})]$$

If such CHP heat production exceeds the capacity then the boiler is operated and the CHP heat production is reduced to the capacity

$$q_{\text{M-H2CHP-Boiler}} = \text{Max} [0, (T_{\text{M-H2CHP}} - q_{\text{M-H2CHP}})]$$

$$q_{\text{M-H2CHP}} = \text{Min} [q_{\text{M-H2CHP}}, T_{\text{M-H2CHP}}]$$

In case of condensing power production

If the condensing power production is positive then the micro CHP unit will try to produce at maximum capacity. And only in the case that excess heat production can not be stored, the CHP unit will be decreased accordingly. Consequently, the CHP heat production is calculated as follows:

$$q_{\text{M-H2CHP}} = \text{Min} [T_{\text{M-H2CHP}}, (h_{\text{M-H2CHP}} - q_{\text{Solar-M-H2CHP}} + (S_{\text{Solar-M-H2CHP}} - S_{\text{Solar-M-H2CHP}}))]$$

The calculations are done separately for each of the three micro CHP systems starting with the H2-CHP system, followed by the Ngas system and the Biomass system. In between each calculation, the condensing power and excess productions are calculated.

6.6.2 Heat pump system

After calculating the CHP systems, the heat pumps systems are calculated in the following way.

Like the CHP system, the heat production and the use of the heat storage give priority to solar thermal, which is calculated as the maximum value of either solar thermal or heat demand plus available room in the heat storage:

$$q_{\text{Solar-M-HP}} = \text{Max} [q_{\text{Solar-M-HP}}, h_{\text{M-HP}} + (S_{\text{Solar-M-HP}} - S_{\text{Solar-M-HP}})]$$

In case of condensing power production

If the solar production is lower than the heat demand and the production on the condensing power plant is positive, then the heat demand will be supplied by the heat storage if possible. And only in the case that this can not be done, the heat pump units will be operated. Consequently, the heat pump heat production is calculated as follows:

$$q_{\text{M-HP}} = \text{Max} [0, (h_{\text{M-HP}} - S_{\text{Solar-M-HP}} - q_{\text{Solar-M-HP}})]$$

If the heat produced by the heat pump exceeds the capacity, then the electric boiler is operated and the heat pump production is reduced to the capacity

$$q_{M-HP-EH} = \text{Max} [0, (T_{M-HP} - q_{M-HP})]$$

$$q_{M-HP} = \text{Min} [q_{M-HP}, T_{M-HP}]$$

In case of CEEP

If CEEP is positive then the heat pump units will try to produce maximum capacity. And only in the case that excess heat production can not be stored, the heat pump units will be decreased accordingly. Consequently, the heat production of the heat pump is calculated as follows:

$$q_{M-HP} = \text{Min} [T_{M-HP}, (h_{M-HP} - q_{\text{Solar-M-HP}} + (S_{\text{Solar-M-HP}} - s_{\text{Solar-M-HP}}))]$$

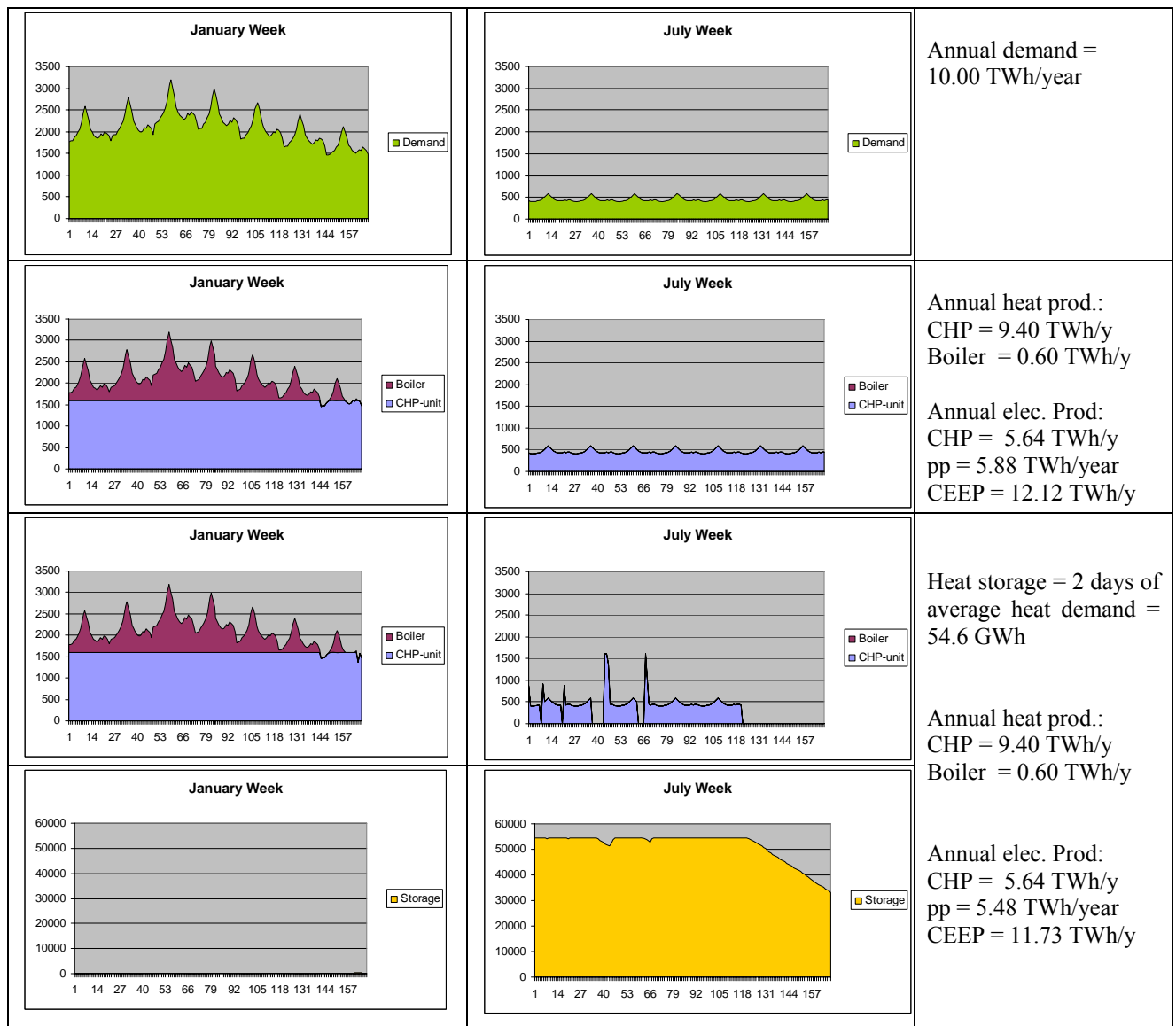


Diagram 6.8: When heat storage capacity is added to the individual micro CHP systems (the two lower diagrams) then the system excess production and power-only production are decreased compared to the reference without any thermal storage (the two upper diagrams).

Diagram 6.8 illustrates how the model functions in the case of no solar thermal production. An annual heat demand of 10 TWh/year is specified and the resulting hour distribution is shown in the upper diagrams for a week in January and a week in July. The next diagram shows the production in the same weeks divided between the CHP unit and the peak load boiler. On an annual basis, the CHP unit produces 9.40 TWh and the boiler produces 0.60 TWh heat. The electricity production of the CHP units is 5.64 and, in the example, the power plant's production is 5.88 TWh/year and the excess production is 12.12 TWh/year. The two lower diagrams show how the model changes the productions IF heat storage capacity is added. The annual heat and electricity productions from the CHP unit are the same, but the heat storage allows for a decrease in the power plant production and the excess production of the total system.

In diagram 6.9, the same calculations are shown in which solar thermal is added to the system. In such case, the model gives priority to the utilisation of the solar thermal input. In the two upper diagrams without heat storage capacity, the solar thermal input can not be fully utilised. When storage capacity is added then such capacity is first used in order to increase the utilisation of solar thermal from 1.25 to 1.49 TWh/year, and then to decrease power-only production and the excess production of the system.

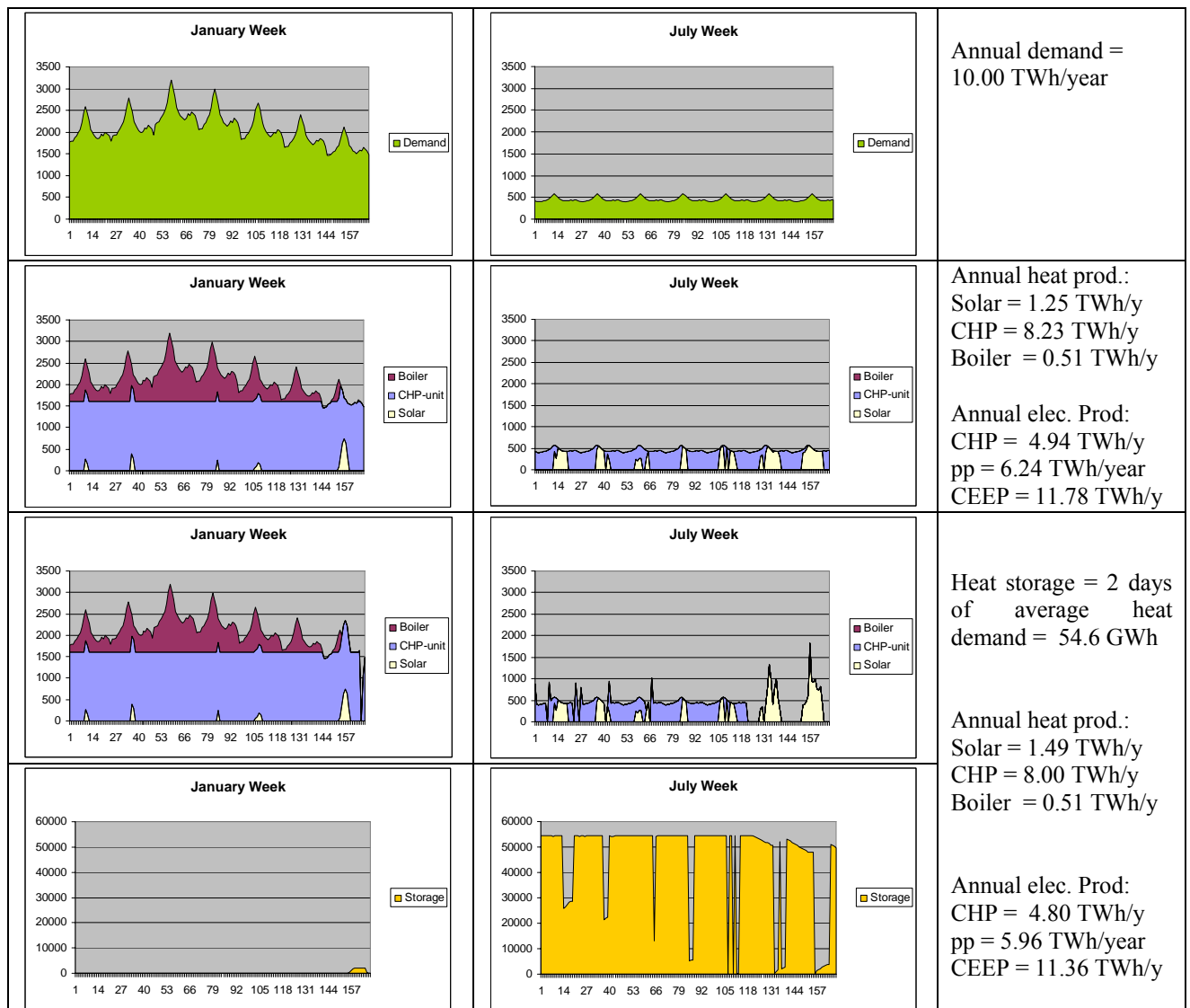


Diagram 6.9: Corresponds to diagram 6.8 plus solar thermal, which is then prioritized.

6.7 Electrolyser for micro CHP, Transportation, DH groups 2 and 3

Four electrolyser systems are described in the model. Two of these are systems which are meant to be located next to the district heating groups 2 and 3 along with the CHP units, Heat Pumps and boilers. Here, the heat production of the electrolysers can be utilised in the district heating supply. The two other systems produce hydrogen for micro CHP systems and for transportation. The electrolyser is meant to be a hydrolyser (producing hydrogen) but can be used for modelling any kind of equipment converting electricity into fuel and heat.

6.7.1 Electrolysers for hydrogen production to individual micro CHP systems

The calculation is based on the result of the input calculation in section 4.6.4., in which the minimum capacity of the electrolyser is identified together with the electricity demand d_{ElcM} . The model seeks to reorganise such production in order to avoid excess and power-only productions.

First, the potential of increasing the production at hours of excess production is identified as the lower value of either CEEP or the difference between the capacity and the production of the electrolyser:

$$d_{ElcM-inc-pot} = \text{Min} [e_{CEEP}, (C_{ElcM} - d_{ElcM})]$$

Secondly, the potential of decreasing production at hours of power-only production is identified as the lower value of either the power production or the electrolyser demand.

$$d_{ElcM-dec-pot} = \text{Min} [e_{PP}, d_{ElcM}]$$

Then a balance is created in which either the potential of increasing or the potential of decreasing is lowered so that the annual potentials are the same:

$$\text{If } D_{ElcM-dec-pot} > D_{ElcM-inc-pot} \text{ then } d_{ElcM-dec-pot} = d_{ElcM-dec-pot} * D_{ElcM-inc-pot} / D_{ElcM-dec-pot}$$

$$\text{If } D_{ElcM-inc-pot} > D_{ElcM-dec-pot} \text{ then } d_{ElcM-inc-pot} = d_{ElcM-inc-pot} * D_{ElcM-dec-pot} / D_{ElcM-inc-pot}$$

A new optimal distribution of the electrolyser electricity demand (producing exactly the same annual fuel as before) is calculated as:

$$d_{ElcM} = d_{ElcM} - d_{ElcM-dec-pot} + d_{ElcM-inc-pot}$$

Finally, such distribution is evaluated against the hydrogen storage capacity. First, the changes in storage content S_{ElcM} are calculated

$$S_{ElcM}(x) = S_{ElcM}(x-1) + d_{ElcM}(x) * \alpha_{ElcM} - f_{M-NgasCHP-Total}(x)$$

If the storage content based on such calculation is below zero, the production on the electrolyser is raised:

$$\text{If } S_{ElcM} < 0 \text{ then } d_{ElcM} = d_{ElcM} + (-S_{ElcM} / \alpha_{ElcM})$$

And if the storage content exceeds the storage capacity then the production on the electrolyser is decreased:

$$\text{If } S_{ElcM} > S_{ElcM} \text{ then } d_{ElcM} = d_{ElcM} + (S_{ElcM} - S_{ElcM})$$

6.7.2 Electrolysers for hydrogen production to transportation

After calculating the regulation of the electrolyser for individual micro hydrogen CHP systems the calculation of excess and power-only production (section 6.1) is repeated, and then the calculation of

the hydrogen production for transportation is done exactly the same way as for the micro CHP, as described above in section 6.7.1.

6.7.3 Electrolysers in district heating systems

The regulation of the electrolysers in the district heating system is used solely in order to avoid critical excess electricity production, exactly as the two other electrolysers. However, the electrolysers in the district heating system do not have to produce a certain amount of hydrogen (as the two other electrolysers, which have to fulfil the demands of the hydrogen CHP and transportation systems).

The sequence of the calculations is as follows. First, the electrolysers of district heating groups 3 and 2 are calculated. After each calculation, the calculation of excess production (section 6.1) is repeated.

The electrolysers in each of the district heating systems are regulated in the following way:

The electrolyser is used for producing fuel in the case of critical excess production, $e_{CEEP} > 0$.

The fuel is used for reducing the fuel consumption of the CHP unit and the boiler of the particular group.

If the thermal efficiency is equal to 0, then the use of electrolysers is simply calculated as the minimum value of either the CEEP value or the capacity of the electrolysers.

$$\text{If } \rho_{Eic} = 0 \text{ Then } e_{Eic} = \min(e_{CEEP}, C_{Eic})$$

If the thermal efficiency is positive, the heat of the electrolyser is used for reducing heat production of other units according to the following priority:

- reduce boiler production
- reduce CHP production
- reduce heat pump production
- wasted

Step1: Replace boiler heat production

First, the potential replacement of the boiler is calculated as the minimum value of either (1) the critical excess production, (2) the capacity of the electrolyser, or (3) the electricity consumption responding to the heat production of the boiler. The latter is found as the heat production of the boiler divided by the thermal efficiency of the electrolyser. The excess production and the productions of the boiler and the electrolyser are then adjusted accordingly.

$$\text{Potential} = \min(e_{CEEP}, C_{Eic}, q_B / \rho_{Eic})$$

$$e_{CEEP} = e_{CEEP} - \text{Potential}$$

$$e_{Eic} = \text{Potential}$$

$$q_{Eic} = \text{Potential} * \rho_{Eic}$$

$$q_B = q_B - \text{Potential} * \rho_{Eic}$$

Step 2: Replace CHP heat production

If the excess production is still positive, then the potential decrease in the CHP unit is found, first by calculating the factor which will make it possible to remove critical excess production without creating import. This factor takes into account the fact that the replacement of the CHP by the electrolyser

influences the excess production, as the CHP production is decreased and the electrolyser consumption is increased. The factor is determined by the following equations:

$$\delta e_{CEEP} = \delta e_{CHP} + \delta e_{Elc}$$

$$\delta q_{CHP} = \delta q_{Elc}$$

$$\delta q_{Elc} = \delta e_{Elc} * \rho_{Elc}$$

$$\delta q_{CHP} = \delta e_{CHP} * \rho_{CHP} / \mu_{CHP}$$

The factor then becomes:

$$\text{Factor} = 1 + \rho_{CHP} / (\mu_{CHP} * \rho_{Elc})$$

The factor is used for identifying the potential replacement of the CHP in which the combination of the CHP decrease and the electrolyser increase outbalances the excess production. Consequently, the potential CHP reduction is found as the critical excess production divided by the factor. Again, the potential replacement of the CHP unit is found as the minimum value of either such reduction or the capacity of the electrolyser or the electricity consumption responding to the heat production of the CHP unit.

$$\text{Potential} = \min [e_{CEEP} / \text{Faktor} , (C_{Elc} - e_{Elc}) , q_{CHP} / \rho_{Elc}]$$

In the case of group 3, the potential reduction in the heat production of the CHP unit is found as the difference between the actual production and the minimum production according to the regulation inputs.

$$\text{In group 3: Potential} = \min [e_{CEEP} / \text{Faktor} , (C_{Elc3} - e_{Elc3}) , (q_{CHP3} - q_{CHP3\text{-minimum}}) / \rho_{Elc}]$$

Again, the excess production and the production of the CHP and the electrolyser are then adjusted accordingly similar to the previous case of the boiler.

Step 3: Replace the heat production of the heat pump

If the excess production is still positive then the potential decrease in the heat pump (HP) unit is found, first by calculating the factor which will make it possible to remove critical excess without creating import. This factor takes into account the fact that the replacement of the HP by the electrolyser influences the excess production, as HP production decreases and electrolyser consumption increases. The factor is determined by the following equations:

$$\delta e_{CEEP} = \delta e_{HP} + \delta e_{Elc}$$

$$\delta q_{HP} = \delta q_{Elc}$$

$$\delta q_{Elc} = \delta e_{Elc} * \rho_{Elc}$$

$$\delta q_{HP} = \delta e_{HP} * \phi_{HP}$$

And the factor then becomes:

$$\text{Factor} = \phi_{HP} / \rho_{Elc} - 1$$

The factor is used for identifying the potential replacement of the HP by which the combination of the HP decrease and the electrolyser increase outbalances the excess production. Consequently, the potential HP reduction is found as the critical excess production divided by the factor. Again, the potential replacement of the HP unit is found as the minimum value of either such reduction or the capacity of the electrolyser or the electricity consumption responding to the heat production on the HP unit.

$$\text{Potential} = \min (e_{\text{CEEP}} / \text{Faktor} , (C_{\text{Elc}} - e_{\text{Elc}}), q_{\text{HP}} / \rho_{\text{Elc}})$$

Again, the excess production and the production of the HP and the electrolyser are then adjusted accordingly similar to the previous case of the boiler and the CHP.

Step 4: Electrolyser heat production is wasted

If the excess production is still positive then the potential increase in the electrolyser is simply found as the minimum value of either the excess production or the remaining increase up to the capacity of the electrolyser.

$$\text{Potential} = \min [e_{\text{CEEP}} , (C_{\text{Elc}} - e_{\text{Elc}})]$$

The excess production and the production of the electrolyser are then adjusted accordingly.

6.8 Heat storage in groups 3 and 2

To improve the possibilities of minimising the electricity export, the heat storage capacity is included in the model for each of the district heating groups 2 and 3. Again, such storage capacities are used for minimising the excess and power-only productions in the system.

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 excess electricity production e_{CEEP} and CHP in group 3
- 2: Critical excess electricity production e_{CEEP} and CHP in group 2
- 3: Exportable excess electricity export, e_{EEEP} and CHP in group 3
- 4: Exportable excess electricity export, e_{EEEP} and CHP in group 2

In order to achieve balance, the calculations are performed over a series of 2-week periods, in which the storage content at the end of the year is equal to the storage content at the beginning of the 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 minor of the potential increase in district heating production from HP, $q_{\text{HP-inc}}$ and the potential increase in storage content, s_{inc} are determined.

$$q_{\text{HP-inc}} = \min(e_{\text{EEP}}, C_{\text{HP}} - e_{\text{HP}}) * (T_{\text{HP}}/C_{\text{HP}})$$

$$s_{\text{inc}} = S_{\text{DH}} - s_{\text{DH}}$$

New values can now be calculated:

$$e_{\text{HP}} = e_{\text{HP}} + \min(q_{\text{HP-inc}}, s_{\text{inc}}) * (C_{\text{HP}}/T_{\text{HP}})$$

$$e_{\text{EEP}} = e_{\text{EEP}} - \min(q_{\text{HP-inc}}, s_{\text{inc}}) * (C_{\text{HP}}/T_{\text{HP}})$$

$$q_{\text{HP}} = q_{\text{HP}} + \min(q_{\text{HP-inc}}, s_{\text{inc}})$$

$$s_{\text{DH}} = s_{\text{DH}} + \min(q_{\text{HP-inc}}, s_{\text{inc}})$$

B: Moving the electricity production from condensing plants, e_{PP} , to CHP plants

First, the minimum condensing power plant production needed in order to stabilise the grid is found (see section 6.1 for more details):

$$e_{\text{PP-min}} = (e_{\text{Total}} * \text{Stab}_{\text{total}} - e_{\text{CHP2}} * \text{Stab}_{\text{CHP2}} - e_{\text{RES1}} * \text{Stab}_{\text{RES1}} - e_{\text{RES2}} * \text{Stab}_{\text{RES2}} - e_{\text{RES3}} * \text{Stab}_{\text{RES3}} - e_{\text{RES4}} * \text{Stab}_{\text{RES4}} - e_{\text{CHP3}} - e_{\text{Nuclear}} - e_{\text{Hydro}} - e_{\text{V2G}}) / (1 - \text{Stab}_{\text{total}})$$

Then the potential increase in district heating production from CHP, $q_{\text{CHP-inc}}$, and the potential increase in storage content, s_{inc} , are determined

$$q_{\text{CHP-inc}} = \min [(C_{\text{CHP}} - e_{\text{CHP}}) ; (e_{\text{PP}} - e_{\text{PP-min}})]$$

$$s_{\text{inc}} = S_{\text{DH}} - s_{\text{DH}}$$

New values can now be calculated:

$$e_{\text{CHP}} = e_{\text{CHP}} + \min(q_{\text{CHP-inc}}, s_{\text{inc}}) * (C_{\text{CHP}}/T_{\text{CHP}})$$

$$e_{\text{PP}} = e_{\text{PP}} - \min(q_{\text{CHP-inc}}, s_{\text{inc}}) * (C_{\text{CHP}}/T_{\text{CHP}})$$

$$q_{\text{CHP}} = C_{\text{CHP}} + \min(q_{\text{CHP-inc}}, s_{\text{inc}})$$

$$s_{\text{DH}} = s_{\text{DH}} + \min(q_{\text{CHP-inc}}, s_{\text{inc}})$$

C: Reducing the CHP production in situations with electricity export

First, the minimum CHP production needed in order to stabilise the grid is found. In the case of district heating (DH) group 2:

$$e_{\text{CHP2-min}} = (e_{\text{Total}} * \text{Stab}_{\text{total}} - e_{\text{RES1}} * \text{Stab}_{\text{RES1}} - e_{\text{RES2}} * \text{Stab}_{\text{RES2}} - e_{\text{RES3}} * \text{Stab}_{\text{RES3}} - e_{\text{RES4}} * \text{Stab}_{\text{RES4}} - (e_{\text{PP}} / \text{Stab}_{\text{Total}}) - e_{\text{CHP3}} - e_{\text{Nuclear}} - e_{\text{Hydro}}) / \text{Stab}_{\text{CHP2}}$$

And in the case of DH group 3:

$$e_{\text{CHP3-min}} = e_{\text{Total}} * \text{Stab}_{\text{total}} - e_{\text{RES1}} * \text{Stab}_{\text{RES1}} - e_{\text{RES2}} * \text{Stab}_{\text{RES2}} - e_{\text{RES3}} * \text{Stab}_{\text{RES3}} - e_{\text{RES4}} * \text{Stab}_{\text{RES4}} - (e_{\text{PP}} / \text{Stab}_{\text{Total}}) - e_{\text{Nuclear}} - e_{\text{Hydro}} - (e_{\text{CHP2}} / \text{Stab}_{\text{CHP2}})$$

If $e_{\text{CHP3-min}} < C_{\text{CHP3-min}}$ **then** $e_{\text{CHP3-min}} < C_{\text{CHP3-min}}$

Secondly, the potential of decreasing the CHP heat production, $q_{\text{CHP-red}}$, is found as the lower value of either the excess production or the difference between the actual production and the minimum production required for grid stabilisation.

$$q_{\text{CHP-red}} = \min(e_{\text{EEP}} ; e_{\text{CHP}} - e_{\text{CHP-min}}) * (T_{\text{CHP}}/C_{\text{CHP}})$$

New values can now be calculated:

$$e_{\text{CHP}} = e_{\text{CHP}} - \min(q_{\text{CHP-red}} , s_{\text{DH}}) * (C_{\text{CHP}}/T_{\text{CHP}})$$

$$e_{\text{EEP}} = e_{\text{EEP}} - \min(q_{\text{CHP-red}} , s_{\text{DH}}) * (C_{\text{CHP}}/T_{\text{CHP}})$$

$$q_{\text{CHP}} = q_{\text{CHP}} - \min(q_{\text{CHP-red}} , s_{\text{DH}})$$

$$s_{\text{DH}} = s_{\text{DH}} - \min(q_{\text{CHP-red}} , s_{\text{DH}})$$

D: Reducing boiler production.

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

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

New values can now be calculated:

$$q_{\text{B}} = q_{\text{B}} - \min(q_{\text{B-red}} ; s_{\text{DH}})$$

$$s_{\text{DH}} = s_{\text{DH}} - \min(q_{\text{B-red}} ; s_{\text{DH}})$$

6.9 Transportation (Smart charge and V2G)

Definition of inputs:

- D_{V2G} : Transportation Demand of V2G cars in TWh/year (defined as demand from the grid)
- δ_{V2G} : The distribution of the transportation demand in 8784 hourly values.
(The numbers are relative e.g. each ranging 0 to 1).
- $C_{Charger}$: The capacity of the grid connection in MW
- $V2G_{MaxShare}$: The maximum share of V2G cars which are driving during peak demand hour.
- $\mu_{Charger}$: The efficiency of the grid to battery connection (charger).
- $\mu_{Inverter}$: The efficiency of the battery to grid connection (inverter).
- $S_{V2G-Battery}$: The capacity of the battery storage in GWh
- $V2G_{Connection-Share}$: The share of parked V2G cars connected to the grid.

All inputs are expressed for the entire utility system analysed, and for the entire vehicle fleet within the service territory of that utility system. Thus, for example, the maximum system capacity $C_{Charger}$ is calculated on the basis of the line maximum power of a single car multiplied by the maximum number of vehicles plugged in at any given time.

One important input is the distribution of the transportation demand (δ_{V2G}), which is used for two purposes. One is to determine how many V2G cars are driving and consequently not connected to the grid at the hour in question. This, together with the $V2G_{Max-Share}$ (the maximum share of V2G cars which are driving during peak demand hour) and the $V2G_{Connection-Share}$, determines the fraction of the V2G fleet that is available to the electrical system at any given hour. The other purpose for δ_{V2G} is to determine the discharging of the battery storage for driving.

Initial input calculations

The hourly transportation demand and thereby the discharging of the battery (t_{V2G}) is calculated as follows:

$$t_{V2G} = [D_{V2G} * \delta_{V2G} / \sum \delta_{V2G}] * \eta_{CHARGE}$$

The grid connection capacity of the total V2G fleet on an hourly basis (c_{V2G}) will be calculated as follows:

$$c_{V2G} = C_{Charger} * V2G_{Connection-Share} * ((1 - V2G_{Max-Share}) + V2G_{Max-Share} * (1 - \delta_{V2G}/\text{Max}(\delta_{V2G})))$$

This formula is constituted by three factors. The first factor is $C_{Charger}$, the power capacity of the entire V2G fleet. This is multiplied by $V2G_{Connection-Share}$, the fraction of the parked vehicles which is assumed to be plugged. The third factor, in parentheses, calculates the fraction of vehicles on the road at each hour. Further decomposing the third parenthesized factor, it consists of the sum of two terms. The first term, $(1 - V2G_{Max-Share})$, represents the minimum fraction of vehicles parked. The second term is the additional fraction of vehicles parked during non-rush hours. The hourly fraction of vehicles parked is derived from the known input of hourly energy demand for the fleet. This formula yields c_{V2G} , the power capacity of all connected V2G vehicles, at any given hour. This is a calculation of capacity, not considering whether sufficient battery power is available; the latter is treated in the next section.

The calculation works as described in the following example of 1.9 million cars, each with a grid connection of 10 kW and each with a demand of 2 MWh/year equal to 20,000 km/year. The charger and inverter efficiencies are each defined as 0.9. In total, the demand for transportation becomes $D_{V2G}=3.8$ TWh/year and a maximum capacity of 19,000 MW. The power used is distributed between a peak demand during rush hours between 7:00 and 9:00 a.m. and another one between 16:00 and 18:00 p.m., as shown in the diagram for one week (Please, recall that this is battery demand, not electric system demand, as the vehicles are necessarily disconnected from the grid while driving).

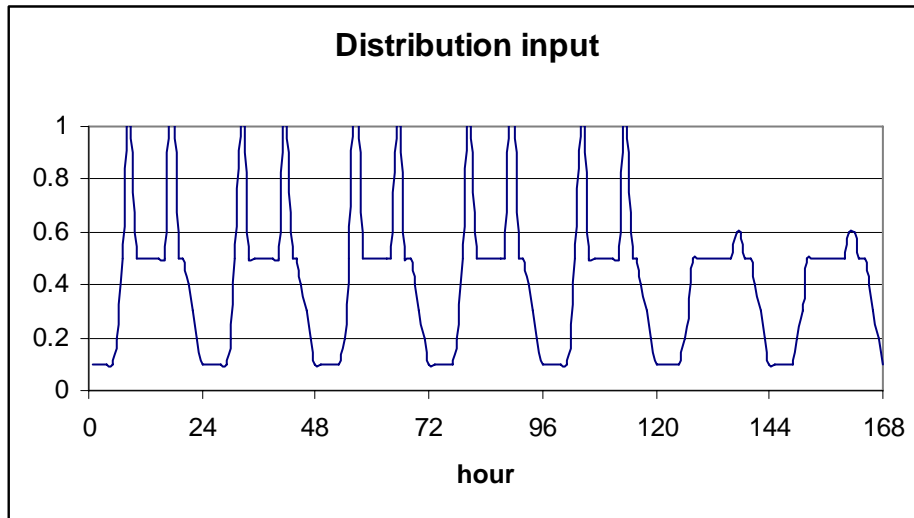


Diagram 6.10: Input distribution of transportation demand

Based on such information, the model will calculate the distribution of the demand and thereby also the discharging of the battery, as shown in the next diagram. The sum of the diagram within a year becomes 3.42 TWh/year equal to $0.9 * 3.8$ TWh/year.

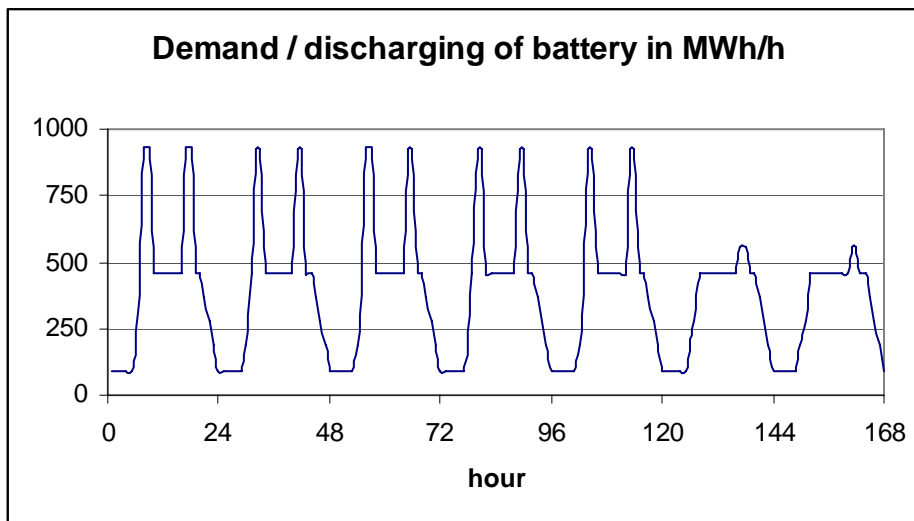


Diagram 6.11: Transportation demand and discharging of battery.

The calculation of the available grid connection depends on the definition of both the maximum share of V2G cars, $V2G_{MaxShare}$, and the share of parked vehicles which are connected, $V2G_{ConnectionShare}$. If both are 100 per cent, the result is as shown in the upper figure of diagram 6.12. In such case, the model assumes that all vehicles are driving during peak demand and, consequently, the grid connection becomes zero. During low demand, the grid connection becomes equal to the maximum grid connection $C_{Charger}$, subtracting the few vehicles that are driving.

Even during peak demand (rush hour), the model does not assume all vehicles to be driving. By setting the $V2G_{MaxShare}$ value one can define how many cars are parked and potentially connected to the grid during peak demand. In diagram 6.12, (the figure in the middle), the $V2G_{MaxShare}$ has been defined as 20 per cent representing a typical situation in which a minimum of 80 per cent of all cars are parked during rush hours (Kempton et al 2001).

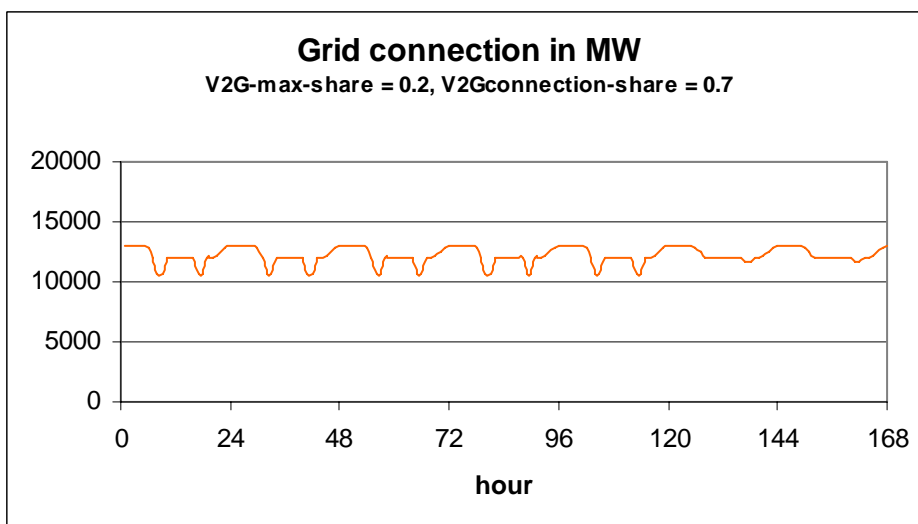
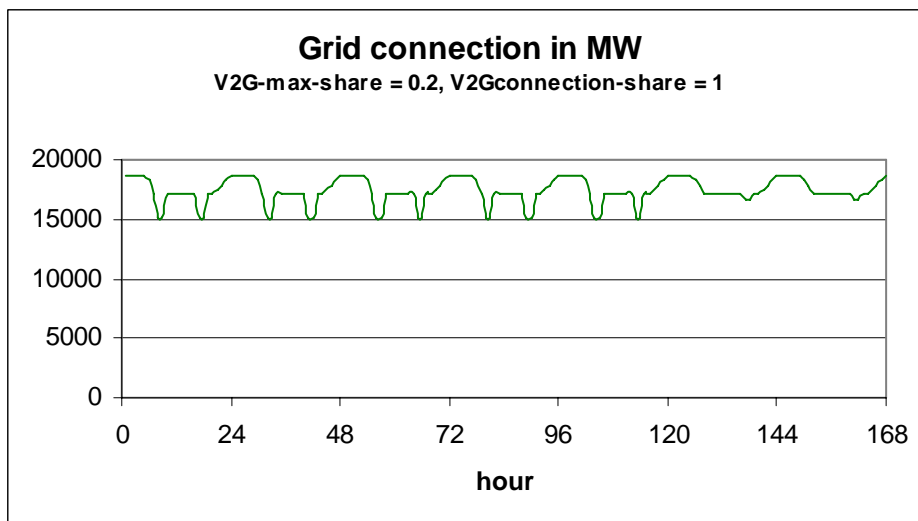
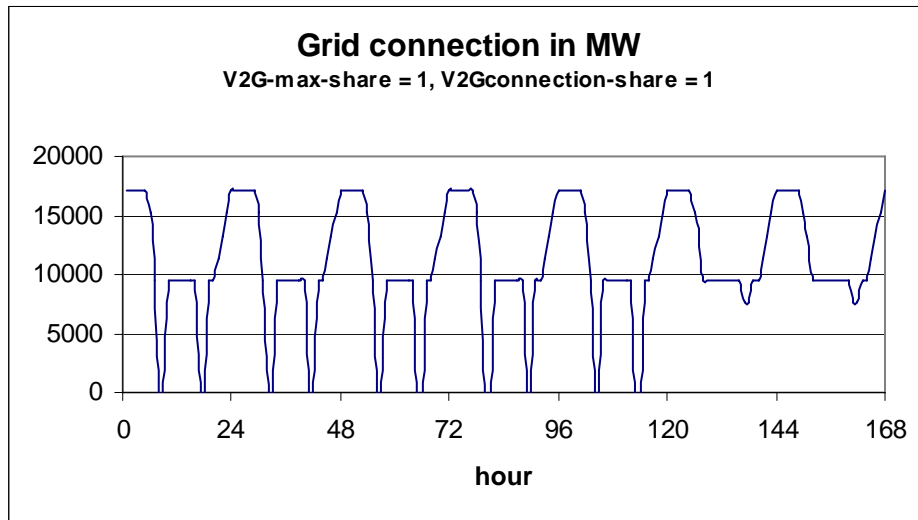


Diagram 6.12: The model calculation of the available grid connection for three different combinations of input definitions.

In the lower figure of diagram 6.12, the input of the share of parked vehicles which are connected, $V2G_{\text{ConnectionShare}}$, has been changed from 100 to 70 per cent and, consequently, the grid connection is decreased in general by 30 per cent compared to fig 2.

Considerations on the modelling of the battery and loading before disconnecting

The batteries of the V2G fleet are modelled as if one “big battery” existed for the entire vehicle fleet. The available battery capacity is equal to the maximum capacity. In reality, the total capacity of the battery is not available all the time, since some of the cars will be driving, and can neither discharge to, nor charge from, the grid; others will need to drive during the next few hours and thus cannot be discharged. However, the model assumes for simplicity that the batteries for the cars are scheduled to be fully loaded when they disconnect and start driving. Consequently, the model does not gain much from keeping separate account on the share of the battery, which is not connected, since this part would typically within the hour be fully loaded anyway. However, the share representing the cars driving will discharge a bit from one hour to another in the case of cars driving for more than one hour. If one wants to take such issues into consideration, one could simply make a small reduction in the input value for the capacity of the battery, $S_{V2G\text{-Battery}}$.

The model is required to make sure that the individual car is fully loaded before it is planned to disconnect. In general, the batteries are loaded in the case of excess electric power production. However, when there is not excess power production, the model has to make sure that the batteries are loaded prior to driving periods. (In a future refinement of the model, we may assume that the vehicle controller is able to infer how much charge is needed and would not need to always fully charge if there is no excess production and vehicle use is highly regular; e.g. if intercity trips are only taken on Saturdays, the battery may not need to be fully charged at early mornings during weekdays.)

The model assumes that the scheduler on each car is 100% accurate about when the driver will need to drive again. Therefore, the scheduler is assumed to prioritize charging of the cars that will drive again within the next few hours, so if there is only a small amount of excess wind, it is directed to the cars that will be in use next time. That is, during each hour, the model inspects the next e.g. two hours' driving needs, and if there is not enough in the big battery for this, then the charging is forced even in the case of lack of excess production, specifically, if needed, fossil fuel power plants will be switched on if there is not enough excess wind.

Such procedure simulates a situation in which the individual car owner will make priorities on how to optimise between low costs of charging and security of fully loaded batteries when starting to drive. The car owner does this by setting prices and limitations to the computer control of the car. However, the car owner will learn from experience, and will soon know how to optimise. He will also know how many hours in advance he must start the charging of the battery even in the case of no low prices.

Here, the model on its own identifies the necessary number of hours to be able to secure driving and thereby the minimum battery loading. The necessary number of hours will depend on both the shape and pattern of the distribution of the transportation demand, as well as on the definition of the rest of the energy system. For example, a system in which the excess production is severe will call for less “pre-loading” than a system in which the excess production is small.

The necessary hours of “pre-loading” is found by use of try-and-error. The model starts by assuring that the battery always has the minimum load required in order to supply the next one hour and if this results in lack of battery content the number is raised to two, etc. The number of hours becomes a result of the calculation. In an optimized electric control system, the number of hours prior to driving might also be determined by weather forecasts regarding anticipated wind for the next few hours, but we do not consider such refinements here.

Modelling of the V2G cars

For each hour, the model calculates as follows. The V2G cars are told to charge in the case of available excess electricity production for that hour (e_{CEEP}) and available battery energy capacity ($S_{V2G-Battery} - S_{V2G-Battery}$) within the limitations of the power capacity of the grid connection (c_{V2G}) for that hour. Thus, the formula takes the minimum of these three values:

$$e_{Charge} = \min [e_{CEEP}, (S_{V2G-Battery} - S_{V2G-Battery}) / \mu_{Charge}, c_{V2G}]$$

Moreover, as mentioned above, the charging is forced in the case in which the transport demands of the present and the next “y” hours cannot be supplied by the battery content. Initially, the “y” value is set to one hour. If this leads to lack of battery content the value is raised in steps of one hour.

The minimum battery content needed is calculated:

	x=a
$S_{V2G-Battery-min} =$	$\sum t_{V2G}$
	a+y

Then the charging of the battery is adjusted accordingly, by requiring that:

$$e_{Charge} \geq [S_{V2G-battery} - S_{V2G-Battery-min}] / \mu_{Charge}$$

If e_{Charge} becomes higher than the capacity of the grid connection c_{V2G} then the number of hours, y, is raised by one, and the calculations start all over again.

The new battery content is then calculated by adding the above charging and subtracting the discharging caused by driving (t_{V2G}):

$$S_{V2G-Battery} := S_{V2G-Battery} - t_{V2G} + (e_{Charge} / \mu_{Charge})$$

The V2G cars are told to supply to the grid in the case of potential replacement of production from power plants (e_{PP}) and available stored electricity in the battery after the supply of the transportation demand:

$$e_{Inv} = \min [e_{PP}, ((S_{V2G-Battery} - S_{V2G-Battery-min}) * \mu_{Inv}), c_{V2G}]$$

The resulting new battery content is then calculated as follows

$$S_{V2G-Battery} := S_{V2G-Battery} - (e_{Inv} / \mu_{Inv})$$

Due to differences in the battery storage content between the beginning and the end of the calculation period (one year), errors may appear in the calculations. To correct these errors, the above calculation is repeated until the storage content at the end is the same as at the beginning. Initially, the storage content is defined as 50% of the battery storage capacity. After the first calculation, a new initial content is defined as the resulting content at the end of the former calculation. Such procedure is repeated until the difference is insignificant.

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6.10 Electricity storage

The electricity storage is described in the model as a hydro storage consisting of the following components:

- Pump (converting electricity to potential energy) defined by a capacity and an efficiency
- Turbine (converting potential energy to electricity) defined by a capacity and an efficiency
- Storage (storing energy) defined by a capacity.

Meanwhile, the hydro storage can be used for modelling any kind of electricity storage such as for example batteries.

The regulation of the storage is used solely in order to avoid critical excess electricity production. The storage facility is regulated in the following way:

The pump is used for filling the storage in the case of critical excess production, $e_{CEEP} > 0$. In such case, the available space in the storage ($S_{CAES} - S_{CAES}$) is calculated and the electricity demand of the pump (e_{Pump}) is found as the minimum value of the following three figures:

- e_{CEEP} , the critical excess production
- $(S_{CAES} - S_{CAES}) / \alpha_{Pump}$ available storage capacity divided by the pump efficiency
- C_{Pump} , the maximum capacity of the pump.

$$\text{If } e_{CEEP} > 0 \text{ then } e_{Pump} := \min [e_{CEEP}, (S_{CAES} - S_{CAES}) / \alpha_{Pump}, C_{Pump}]$$

$$S_{CAES} = S_{CAES} + e_{Pump} / \alpha_{Pump}$$

The turbine is used for emptying the storage by replacing the power plant if the production from the power plant, $e_{PP} > 0$. In such case, the content of the storage (S_{CAES}) is identified and the electricity production of the turbine ($e_{Turbine}$) is found as the minimum value of the following three figures:

- e_{PP} , the electricity production of the power plant
- $S_{CAES} * \mu_{Turbine}$, storage content multiplied by the turbine efficiency
- $C_{Turbine}$, the maximum capacity of the turbine.

$$\text{If } e_{PP} > 0 \text{ then } e_{Turbine} := \min [e_{PP}, S_{CAES} * \mu_{Turbine}, C_{Turbine}]$$

$$S_{CAES} = S_{CAES} - e_{Turbine} / \mu_{Turbine}$$

Due to differences in the storage content between the beginning and the end of the calculation period, errors may appear in the calculations. In order to correct these errors, the above calculation is repeated until the storage content at the end is the same as at the beginning. Initially, the storage content is defined as 50% of the storage capacity. After the first calculation, a new initial content is defined as the resulting content at the end of the former calculation. Such procedure is repeated until the difference is insignificant.

CAES (Compressed Air Energy Storage)

The electricity storage facility can also be used to model a Compressed Air Energy Storage component. The CAES component is modelled in a similar way to the pumped hydro storage, the main difference being the fuel consumption at the electricity production stage. Consequently, one has to specify a CAES fuel ratio, ϕ_{CAES} , which is defined as fuel input divided by the electricity production of the turbine, $e_{Turbine}$

Please, note that in CAES, the main loss in the storage is heat loss, which occurs only during the initial hours after compression. As a certain time usually elapses before the expansion phase begins, the heat loss in the storage is included in the compressor efficiency definition.

The compressor is utilized in the model after calculating the heat and electricity production of the CHP and power plants, but before reducing excess electricity by use of other means. In the case of having pumped hydro storage into the system, this is prioritized over the CAES plant operation.

The turbine is utilized in order to replace power plant production.

7. Market-Economic Optimisation

If market-economic regulation is chosen in the input regulation window the following optimisation procedure is used. The model distinguishes between business economy (including taxes) and socio economy (NOT including taxes). Basically, the model identifies the lowest cost solution of the system, assuming an electricity market on which all plant operators seek to optimise their business-economic profit.

7.1 Net import and resulting external market price

The market-economic modelling is based on the identification of the market price at each hour resulting from the demand and supply of electricity. Moreover, the exact production of the various units in which the resulting market price becomes equal to the marginal production price is identified. Similar balance prices are found for electricity-consuming units such as heat pumps and electrolyzers.

Consequently, the following types of calculations are done continuously as an integrated part of each of the following sequences (sections 7.2 – 7.9) in the market-economic optimisation procedure.

7.1.1 Calculating the resulting market price

First, the net import is identified as the difference between the electricity demand d_{Total} and the supply e_{Total} :

$$d_{Net-Import} = d_{Total} - e_{Total}$$

$$d_{Total} = d_E + d_{EX} + d_{FX} + d_{Cool} + d_{Elc} + d_{BEV} + d_{V2G} + d_{I-HP-total} + d_{I-EH} + d_{HP2} + d_{HP3} + d_{Pump} + d_{HydroPump}$$

$$\text{in which } d_{FX} = d_{FXDay} + d_{FXWeek} + d_{FX4Week}$$

$$\text{and } d_{Elc} = d_{Elc2} + d_{Elc3} + d_{ElcT} + d_{ElcM}$$

$$e_{Total} = e_{PP} + e_{RES} + e_{M-CHP} + e_{Hydro} + e_{Nuclear} + e_{V2G} + e_W + e_{CSHP} + e_{CHP2} + e_{CHP3} + e_{CHP3-MIN} + e_{Turbine}$$

$$\text{in which } e_{RES} = e_{RES1} + e_{RES2} + e_{RES3} + e_{RES4}$$

$$\text{and } e_{M-CHP} = e_{M-h2CHP} + e_{M-NgasCHP} + e_{M-BioCHP}$$

In the calculation of the net import, the production from CHP3 is divided into e_{CHP3} and $e_{CHP3-Min}$ as explained in section 7.3 below.

The market price on the external market, p_X , is now found as follows:

$$p_X = p_i + (p_i / p_o) * Fac_{depend} * d_{Net-Import}$$

where p_i is the system market price (see section 4.3),
 Fac_{depend} is the price elasticity (DKK/MWh/MW)
 p_o is the basic price level for price elasticity (input),
 $d_{Net-Import}$ is the trade on the market.

Import is calculated as positive and export is negative, resulting in an increase in the market price in case of import and a decrease in case of export.

7.1.2 Calculating the balance production

The balance production from a certain unit in which the resulting market price becomes equal to the marginal production price is identified as an integrated part of the procedure. Here, such calculation is illustrated by the example of the geothermal power plant.

First, the net-import, $d_{\text{Net-Import}}$, is calculated as well as the market price, p_x , as described above in section 7.1.1, when the electricity production of the geothermal power plant is zero.

Then the balance production is calculated as follows:

$$\text{BalanceProduction}_{\text{Geothermal}} = - [(\text{VEPP}_{\text{Geothermal}} - p_x) / (\text{Fac}_{\text{depend}} * p_x / p_o) - d_{\text{Net-Import}}]$$

where $\text{VEPP}_{\text{Geothermal}}$ is the marginal production cost of geothermal power production
 p_x is the market price before geothermal production (see section 7.1.1),
 $\text{Fac}_{\text{depend}}$ is the price elasticity (DKK/MWh/MW)
 p_o is the basic price level for price elasticity (input),
 $d_{\text{Net-Import}}$ is the trade on the market before geothermal production

The formula is typically subject to the limitations of power plant capacity.

7.2 The overall procedure

The optimisation is done in the following steps:

Step 1: Electricity Market Definition

The electricity market is defined by the inputs in the Regulation window as described in section 4.13. The fluctuations of the market prices are presented as an hour by hour distribution file. One can change such prices by adding or multiplying figures as described in section 4.13. The influence of import/export on the external market prices is given in terms of a dependency factor (price elasticity and an basic price level for the price elasticity).

When the business-economic best operation strategy is identified for each plant in the following, the influence on the market price is taken into consideration.

Step 2: Identifying marginal production (and consumption) costs

All marginal production costs are calculated on the basis of fuel costs, taxes, CO2 costs and variable operation costs as described in section 4.11. For units connected to district heating plants (such as CHP and heat pumps), power stations and individual micro CHP, marginal costs are given in DKK/MWh electricity production/consumption. For storage units such as hydrogen CHP and pump storage systems, marginal costs are given in a multiplication factor together with an addition factor. Basically, the optimisation criterion is the following:

$$p_{\text{sell}} > p_{\text{buy}} * f_{\text{MUL}} + f_{\text{ADD}}$$

In which p_{sell} is the market electricity price when selling (DKK/MWh)
 p_{buy} is the market electricity price when buying (DKK/MWh)
 f_{MUL} is the multiplication factor (always higher than 1), and
 f_{ADD} is the addition factor (DKK/MWh)

Step 3: Starting point electricity market prices

As a starting point for the optimisation, the electricity system prices are calculated on the basis of:

- the electricity demand including flexible demand (calculated as described in section 6.3)
- the production from RES (Wind power, PV etc.)

As a starting point, all district heating is defined as supplied from boilers.

Then the sequence of optimising the individual plants is identified by the subsequent procedure.

Step 4: Optimising the buying of given hydrogen and electricity demands

The lowest costs solutions of buying the minimum amount of electricity needed to meet the following demands are identified, given the market price fluctuations and limitations in storage capacities etc.:

- for producing hydrogen to transportation
- for charging electric vehicles
- for producing hydrogen for micro CHP systems

When identifying the lowest cost solution for the hydrogen micro CHP systems, the option of producing heat on a boiler using less hydrogen than the CHP unit is considered in situations of high electricity prices.

In the case of V2G (Vehicle to Grid) possibilities, the optimal business-economic solutions of buying and selling are found on the basis of the multiplication and addition factors identified in the Cost Operation window (see section 4.11).

Step 5: Optimising electricity consumption options

Then the following electricity-consuming options are sorted according to the highest marginal consumption costs:

- replacing boiler with heat pumps in district heating group 2
- replacing boiler with heat pumps in district heating group 3
- replacing boiler with electrolysers in district heating group 2
- replacing boiler with electrolysers in district heating group 3
- replacing electric heating with heat pumps in individual houses

Each option is then optimised according to market electricity prices, starting with the option with the highest marginal costs and taking into consideration the fact that each change in consumption influences the market price (increases the price).

Step 6: Optimising hydro power

Then the best business-economic production from hydro power is identified taking into consideration limitations in storage and generator capacities.

In the case of pump possibilities, the optimal business-economic solution of buying and selling are identified on the basis of the multiplication and addition factors identified in the Cost Operation window (see section 4.11).

Step 7: Optimising electricity production options

Then the following electricity production options are sorted according to the lowest marginal costs of production:

- Nuclear
- Geothermal
- Condensing Power plants
- Individual Ngas CHP
- Individual Biomass CHP
- CHP replacing boilers in gr.2
- CHP replacing boilers in gr.3

- CHP replacing heat pumps in gr. 2
- CHP replacing heat pumps in gr. 3
- CHP replacing electrolysers in gr. 2
- CHP replacing electrolysers in gr. 3

Each option is then optimised according to market electricity prices starting with the option with the lowest marginal costs and taking into consideration the fact that each change in consumption influences the market price (decreases the market price).

Limitations in transmission lines are taken into consideration by setting a limit to the production of each unit so that the total export will not exceed the transmission capacity (if possible).

Limitations in import are calculated with regard to the condensing power plants, which will simply be activated in the case that the import transmission capacity is exceeded.

Step 8: Optimising electricity storage (Hydro or battery or CAES storage)

The optimal business-economic solution of buying and selling is identified on the basis of the above-mentioned multiplication and addition factors.

Step 9: Steps 3 to 8 are repeated

In order to calculate the impact on the optimisation of the consumption units after the market price is influenced by the production options, the procedure from steps 3 to 8 is repeated.

Step 10: Critical Excess Production

Any critical excess production is removed following the usual procedure of the technical optimisation of EnergyPLAN (see chapter 8).

7.3 CHP3 minimum production

If a minimum CHP production in district heating group 3 is specified as input in the Regulation window (see section 4.13), then such minimum capacity is treated separately from the rest of the CHP capacity production.

In the beginning of the optimisation procedure, the electricity production, $e_{\text{CHP3-Min}}$, is set as equal to the CHP3 minimum capacity, $C_{\text{CHP3-Min}}$, and the heat production is calculated accordingly. However, if the heat production at one hour exceeds the difference between the district heating demand and the solar thermal and industrial and waste heat productions, then the heat production is reduced accordingly.

$$e_{\text{CHP3-Min}} = C_{\text{CHP3-Min}}$$

$$q_{\text{CHP3-Min}} = e_{\text{CHP3-Min}} * \rho_{\text{CHP3}} / \mu_{\text{CHP3}}$$

If $q_{\text{CHP3-Min}} > d_{\text{DH3}} - q_{\text{Solar3}} - q_{\text{W3}} - q_{\text{Industry-DH3}}$ **then** $q_{\text{CHP3-Min}} = d_{\text{DH3}} - q_{\text{Solar3}} - q_{\text{W3}} - q_{\text{Industry-DH3}}$

The CHP3 capacity is then decreased by the minimum capacity when the optimisation procedure of section 7.8 is done. In the end (after section 7.4 to 7.9), the two sets of production are combined in one resulting CHP3 electricity and heat production.

7.4 District heating supplied by solar thermal and boilers

As a starting point in each of the district heating groups 2 and 3, the boilers are defined to supply all heating after solar thermal production and industrial and waste heat:

$$q_{\text{B}} = h_{\text{DH}} - q_{\text{Solar}} - q_{\text{W}} - q_{\text{CSHP}}$$

7.5 Hydrogen and electricity demands for transportation and micro CHP

Lowest costs solutions of buying the minimum amount of electricity required to meet the following demands are identified given the market price fluctuations and limitations in storage capacities etc.

- for producing hydrogen to transportation
- for charging electric vehicles
- for producing hydrogen for micro CHP systems

7.5.1. Hydrogen for transportation

The model seeks to minimise the business-economic costs of buying electricity to meet the specified hydrogen demand for transportation.

First, the annual electricity demand, $D_{\text{Transport-H2}}$, is calculated on the basis of the annual hydrogen demand, $F_{\text{Transport-H2}}$, (specified in the Input Transport window, section 4.8) and the electrolyser efficiency, α_{ElcT} , (specified in the Input Storage window, section 4.4):

$$D_{\text{Transport-H2}} = F_{\text{Transport-H2}} / \alpha_{\text{ElcT}}$$

The minimum number of electrolyser production hours, $h\text{-MIN}_{\text{ElcT}}$, is calculated as the demand divided by the capacity of the electrolyser:

$$h\text{-MIN}_{\text{ElcT}} = \text{round} (D_{\text{Transport-H2}} / C_{\text{ElcT}})$$

Then the market price (at the present stage of the procedure, i.e. in the beginning with no productions) is identified, as described in section 7.1. Based on these prices, the model identifies the hours of lowest cost production, i.e. the hours up to $h\text{-MIN}_{\text{ElcT}}$ with the lowest market prices. The model identifies the maximum buying price, $p_{\text{ElcT-MAX}}$, if all production hours are placed at times with the lowest possible market prices:

The model now includes the limitations in the hydrogen storage. Basically the electrolysers produce whenever the market price, p_X , is below $p_{\text{ElcT-MAX}}$:

$$\text{If } p_X < p_{\text{ElcT-MAX}} \text{ then } e_{\text{ElcT}} = C_{\text{ElcT}} \text{ else } e_{\text{ElcT}} = 0$$

Then the hydrogen storage content of hour x , $S_{\text{ElcT}}(x)$, is calculated:

$$S_{\text{ElcT}}(x) = S_{\text{ElcT}}(x-1) + e_{\text{ElcT}} * \alpha_{\text{ElcT}} - f_{\text{Transport-H2}}$$

If the storage content at hour x becomes negative, the model looks back from hour x to the nearest hour at which the storage was full, and identifies and activates the available hour of production with the lowest market price. Such procedure is repeated until the storage content at hour x is no longer negative.

On the other hand, if the storage content at hour x exceeds the capacity of the storage, the model looks back from hour x to the nearest hour at which the storage was empty, and identifies and deletes the hour of production with the highest market price. Again such procedure is repeated until the storage content at hour x do no longer exceed the capacity.

Due to differences in the storage content between the beginning and the end of the calculation period, errors may appear in the calculations. In order to correct these errors, the above calculation is repeated until the storage content at the end is the same as at the beginning.

7. 5.2 Electricity demand for transportation (BEV and V2G)

In the input, electricity for transportation is divided into three options. The one is specifying a fixed electricity demand. Such demand is included in the demand as shown in section 7.1.1. The two other options is smart charge BEV and V2G. In both cases, the model seeks to minimise the business-economic costs of buying electricity in order to meet the annual demands. Moreover, in the V2G case, the model seeks to optimise the business-economic profit from buying and selling electricity to the grid.

The starting point for the optimisation is the hourly calculation of the electricity demand (from the grid), d_{V2G} , the transportation demand (from the battery), t_{V2G} , and the charging and discharging capacity, c_{V2G} , calculated as described in section 6.9. Please, note that due to the fact that not all vehicles are connected at the same time the charging capacity changes from one hour to another.

The modelling starts by assuming infinite battery storage capacity and identify by iteration the maximum price of buying, $P_{\max\text{-buy}}$, when the difference between charging and discharging fulfil the electricity demand for transportation.

The iteration is done as follows:

First a $P_{\max\text{-buy}}$ value is assumed.

If the system price is below $P_{\max\text{-buy}}$ then the maximum charging, which will still leave the system price below $P_{\max\text{-buy}}$, is identified, as described under section 7.1.2. Such charging is then activated taking into account limitations in charging capacity.

Then the minimum selling price which will provide a profit is identified as:

$$P_{\text{Min-sell}} > P_{\text{Max-Buy}} * f_{\text{MUL-V2G}} + f_{\text{ADD-V2G}}$$

If the system price is above $P_{\text{Min-sell}}$ then the maximum discharging, which will still leave the system price above $P_{\text{min-sell}}$, is identified, as described under section 7.1.2. Such charging is then activated taking into account limitations in discharging capacity.

After calculating the whole year, the annual charging and discharging values are compared to the electricity transportation demand. The $P_{\max\text{-buy}}$ value is then changed gradually until a balance is found which constitutes the best business-economic profit, provided that the storage capacity is infinite.

Based on this $P_{\max\text{-buy}}$ value, the model takes into consideration the storage limitations in the following way:

The battery storage content of hour x , $s_{V2G}(x)$, is calculated:

$$s_{V2G}(x) = s_{V2G}(x-1) + d_{V2G} * \mu_{\text{Charger}} - t_{V2G} - e_{V2G} / \mu_{\text{Inv}}$$

If the battery storage content in hour x becomes negative, the model first decreases the discharging and then increases the charging until a balance is found.

On the other hand, if the storage content in hour x exceeds the capacity of the storage, the model simply decreases the charging until a balance is found.

Due to differences in the storage content between the beginning and the end of the calculation period, errors may appear in the calculations. In order to correct these errors, the above calculation is repeated until the storage content at the end is the same as at the beginning.

7.5.3. Hydrogen for micro CHP

The model seeks to optimise the business-economic profit of buying electricity in order to meet the specified hydrogen demand for micro CHP and sell electricity from the CHP unit. In the model, the micro CHP system consists of a CHP unit and a boiler supplied by hydrogen only, and consequently, the annual hydrogen demand can vary by shifting from the CHP unit to the boiler and back again. Moreover, both hydrogen and heat storage can be specified which provides for flexibility both as regards when to buy and when to sell electricity on the market.

Then, the model identifies hour by hour the lowest cost operation of the CHP unit and the boiler, taking into account solar thermal and heat storage as well as hydrogen storage capacities, in the following way:

Priority is given to solar thermal production

Priority is given to solar thermal production, and the model first identifies the maximum solar thermal output given the heat demand and the heat storage capacity. As part of the calculation, the model identifies the share of the heat storage, which is occupied by solar thermal as a result of such operation.

Boiler production is the starting point

Then the minimum hydrogen demand, $f_{M-H2CHP-Total}$, and corresponding electrolyser electricity demand, e_{ElcM} , are found in the case when the heating demand after solar thermal production is supplied by the boiler only.

$$q_{M-H2CHP-Boiler} = h_{M-H2CHP} - q_{Solar-M-H2CHP}$$

$$f_{M-H2CHP-Total} = q_{M-H2CHP-Boiler} / \rho_{M-NgasCHP-Boiler}$$

$$e_{ElcM} = f_{M-H2CHP-Total} / \alpha_{ElcM}$$

The marginal price of producing additional hydrogen for the CHP unit is identified

For each hour x the model looks back and forth and identifies a period starting with full hydrogen storage and ending with empty hydrogen storage. For such period, the model identifies marginal lowest cost hour of hydrogen production. Based on the market price at such hour y , p_{buy} , the minimum selling price of the CHP unit in hour x , p_{sell} , which will provide a profit, is calculated as the market price at hour y adjusted for the multiplication and addition prices factors found in section 4.11, which adjust for efficiencies and variable operation costs.

$$p_{sell} > p_{buy} * f_{MUL-M-H2CHP} + f_{ADD-M-H2CHP}$$

The CHP unit is activated if profitable and if allowed by the heat storage

The boiler production is set to zero and the minimum selling price of hour x determines whether the CHP unit should operate. The production is found as the minimum value of either the CHP capacity or the production which will influence the market price to such extent that it will become equal to the minimum selling price.

$$\text{If } p_{sell} < p_x(x) \text{ then } e_{M-H2CHP} = c_{M-H2CHP} \text{ else } e_{M-H2CHP} = 0$$

If it is decided to operate the CHP unit, then the heat storage content is identified:

$$S_{M-H2CHP}(x) = S_{M-H2CHP}(x-1) - h_{M-H2CHP} - q_{Solar-M-H2CHP} - Q_{M-H2CHP}$$

If at hour x , the heat storage content exceeds the capacity then the model looks back from hour x to the nearest hour at which the storage content (minus the share of the storage, which is occupied by solar thermal) becomes lower than the CHP heat production, and identifies the hour y , which has the lowest market price. The production at hour y is decreased until the heat storage content at hour x do not exceed the capacity.

If, on the other hand, the heat storage at hour x becomes below zero, then the boiler is activated.

Identifying minimum production costs of the electrolyser

Based on the optimal hydrogen demand, $F_{M-H2CHP-Total}$, identified above, the electrolysers are now optimised in the same way as were the electrolysers for hydrogen production for transportation. The annual electricity demand D_{ElcM} is calculated on the basis of the annual hydrogen demand, $F_{M-H2CHP-Total}$, and the electrolysers' efficiency, α_{ElcM} (specified in the Input Storage window, section 4.4).

$$D_{ElcM} = F_{M-H2CHP-Total} / \alpha_{ElcM}$$

The minimum number of electrolyser production hours, $h-MIN_{ElcM}$, is calculated as the demand divided by the capacity of the electrolyser:

$$h-MIN_{ElcM} = \text{round} (D_{ElcM} / C_{ElcM})$$

Then the market price (at the present stage of the procedure, i.e. in the beginning with no productions) is identified as described in section 7.1. On the basis of these prices, the model identifies the hours of lowest cost production, i.e. the hours up to $h-MIN_{ElcM}$ with the lowest market prices. The model also identifies the maximum price, $p_{ElcT-MAX}$, of buying if all production hours are done at the lowest possible market price.

Including hydrogen storage capacity limitations

The model now includes the limitations in the hydrogen storage in the same way as for the transportation hydrogen production described in section 7.5.1.

7.6 Electricity Consumption from Heat Pumps and DH electrolysers

The following electricity-consuming options are sorted according to the highest marginal costs:

- replacing boiler with heat pumps in district heating group 2
- replacing boiler with heat pumps in district heating group 3
- replacing boiler with electrolysers in district heating group 2
- replacing boiler with electrolysers in district heating group 3
- replacing electric heating with heat pumps in individual houses

Each option is then optimised according to market electricity prices, starting with the option with the highest marginal costs and taking into consideration the fact that each change in consumption influences the market price (increases the price).

7.6.1 Heat Pumps in district heating groups 2 and 3

If the option of replacing boilers by heat pumps in district heating group 2 has the highest marginal cost, it is then optimised according to market electricity prices in the following way:

First, the system price, p_x , is calculated and the balance production of the heat pump, $\text{BalanceProduction}_{\text{HP2}}$, is found as described in section 7.1.

Then the balance production is limited by the capacity of the heat pump:

$$\text{If } \text{BalanceProduction}_{\text{HP2}} < 0 \text{ then } \text{BalanceProduction}_{\text{HP2}} = 0$$

$$\text{If } \text{BalanceProduction}_{\text{HP2}} > C_{\text{HP}} \text{ then } \text{BalanceProduction}_{\text{HP2}} = C_{\text{HP}}$$

And the corresponding thermal output is calculated:

$$q_{\text{HP2}} = \text{BalanceProduction}_{\text{HP2}} * \phi_{\text{HP2}}$$

If the corresponding heat production is lower than the boiler production, then the boiler production is simply reduced accordingly:

$$\text{If } q_{\text{HP2}} < q_{\text{B2}} \text{ then } q_{\text{B2}} = q_{\text{B2}} - q_{\text{HP2}}$$

However, if the corresponding heat production is higher than the boiler heat production, then the boiler production is set to zero and the heat storage is included in the calculation in the following way:

$$\text{If } q_{\text{HP2}} > q_{\text{B2}} \text{ then } s_{\text{DH2}} = s_{\text{DH2}} + (q_{\text{HP2}} - q_{\text{B2}}) \text{ and } q_{\text{B2}} = 0$$

If such increase in the storage content at hour x has the consequence that the content exceeds the storage capacity ($s_{\text{DH}} > S_{\text{DH}}$), then the model looks back from hour x to the nearest hour at which the content in the storage was empty (lower than the heat production of the heat pump at hour x) and identifies the hour y with the highest market price at which the heat pump was producing. Such production at hour y represents the best alternative to decreasing productions in order to avoid overload at hour x .

The procedure is done in the same way for the heat pumps in district heating group 3.

7.6.2 Electrolysers replacing boilers in district heating groups 2 and 3

If the option of electrolysers replacing boilers in district heating group 2 has the highest marginal cost, it is then optimised according to market electricity prices in the following way:

First the system price, p_x , is calculated and the balance production of the electrolyser, $\text{BalanceProduction}_{\text{Eic2}}$, is found as described in section 7.1.

Then the balance production is limited by the capacity of the heat pump:

$$\text{If } \text{BalanceProduction}_{\text{Eic2}} < 0 \text{ then } \text{BalanceProduction}_{\text{Eic2}} = 0$$

$$\text{If } \text{BalanceProduction}_{\text{Eic2}} > C_{\text{Eic2}} \text{ then } \text{BalanceProduction}_{\text{Eic2}} = C_{\text{Eic2}}$$

And the corresponding thermal output is calculated:

$$q_{\text{Eic2}} = \text{BalanceProduction}_{\text{Eic2}} * \rho_{\text{Eic}}$$

If the corresponding heat production is lower than the boiler production, then the boiler production is simply reduced accordingly; and if it is higher, then the electrolyser production is reduced:

If $q_{\text{Eic}2} < q_{\text{B}2}$ **then** $q_{\text{B}2} = q_{\text{B}2} - q_{\text{Eic}2}$

If $q_{\text{Eic}2} > q_{\text{B}2}$ **then** $q_{\text{Eic}2} = q_{\text{B}2}$ **and** $q_{\text{B}2} = 0$

Finally, the electricity consumption of the electrolyser is found as:

$$d_{\text{Eic}2} = q_{\text{Eic}2} / \rho_{\text{Eic}2}$$

The procedure is done in the same way for the electrolysers in district heating group 3.

7.6.3 Heat Pumps in individual households

If the option of heat pumps in individual households has the highest marginal cost, it is optimised according to market electricity prices in the following way:

Priority is given to solar thermal production. If solar thermal production exceeds the heat demand, priority is given to the excess production in the heat storage. Consequently, the model first calculates the maximum share of the solar thermal production which can be utilised, given the distributions of heat demand and solar thermal and given the capacity of the heat storage.

Then the system price, p_x , is calculated and the balance production of the heat pump, $\text{BalanceProduction}_{\text{M-HP}}$, is found, as described in section 7.1.

The balance production is limited by the capacity of the heat pump:

If $\text{BalanceProduction}_{\text{I-HP}} < 0$ **then** $\text{BalanceProduction}_{\text{I-HP}} = 0$

If $\text{BalanceProduction}_{\text{I-HP}} > C_{\text{I-HP}}$ **then** $\text{BalanceProduction}_{\text{I-HP}} = C_{\text{I-HP}}$

The corresponding thermal output is calculated:

$$q_{\text{I-HP}} = \text{BalanceProduction}_{\text{I-HP}} * \phi_{\text{I-HP}}$$

Now the heat storage content at hour x is calculated as

$$S_{\text{I-HP}}(x) = S_{\text{I-HP}}(x-1) + q_{\text{I-HP}} + q_{\text{I-HP-Solar}} - h_{\text{I-HP}}$$

If the storage content goes below zero, then the electric heating boiler is started:

If $S_{\text{I-HP}} < 0$ **then** $q_{\text{I-HP-Boiler}} = - S_{\text{I-HP}}$

If the storage content at hour x exceeds the storage capacity ($S_{\text{DH}} > S_{\text{DH}}$), then the model looks back from hour x to the nearest hour at which the content in the storage was empty (lower than the heat production of the heat pump at hour x) and identifies the hour y with the highest market price at which the heat pump was producing. Such production at hour y represents the best alternative to decreasing productions in order to avoid overload at hour x.

7.7 Hydro Power

The best business-economic production from hydro power is identified taking into consideration limitations in storage and generator capacities. In the case of pump possibilities, the optimal business-economic solution of buying and selling is found on the basis of the multiplication and addition factors identified in the Cost Operation window (see section 4.11). The optimisation is done in the following way:

First, the maximum potential hydro power production E_{Hydro} is calculated, as described in section 4.3.2, taking into account the distribution of the water supply, the limitations in the water storage and the capacity of the hydro power generator.

Based on this maximum hydro power production, the model identifies the minimum number of production hours, $h\text{-MIN}_{\text{Hydro}}$ as the demand divided by the capacity of the hydro power generator:

$$h\text{-MIN}_{\text{Hydro}} = \text{round} (E_{\text{Hydro}} / C_{\text{Hydro}})$$

Then the model identifies the best hours of production, i.e. the hours up to $h\text{-MIN}_{\text{Hydro}}$ with the highest market prices. The model identifies the minimum production price, $p_{\text{Hydro-Min}}$, if all production hours are done at the highest possible market prices.

The model now includes the limitations in the hydrogen storage in the following way. Basically, hydro power is produced whenever the market price, p_X , is above $p_{\text{Hydro-Min}}$:

$$\text{If } p_X > p_{\text{Hydro-Min}} \text{ then } e_{\text{Hydro}} = C_{\text{Hydro}} \text{ else } e_{\text{Hydro}} = 0$$

Such production fulfils the requirement of utilising the water supply. However, if reversal hydro power options are specified, the model decides if the pump should be used in the following way:

The pump should only be used when the market price is at least below the minimum selling price, $p_{\text{Hydro-Min}}$. If, at one hour x , the hydro power plant is not producing (in accordance with the procedure above on producing only in hours of best market prices), then the model looks back from hour x to the nearest hour at which the hydro power water storage was empty and identifies the minimum price of any hour at which the hydro power was producing.

Based on such minimum selling price at hour y , p_{Sell} , the maximum pumping/buying price, p_{Buy} , which will provide a profit, is calculated as the market price at hour y adjusted for the multiplication and addition price factors found in section 4.11, which adjust for efficiencies and variable pump and turbine costs.

$$P_{\text{Sell}} > p_{\text{Buy}} * f_{\text{MUL-HydroPump}} + f_{\text{ADD-HydroPump}}$$

The minimum selling price is then compared to the market price of hour x , and if the market price is higher, then the hydro power pump, $d_{\text{Hydro-Pump}}$, is activated:

$$\text{If } p_{\text{Sell}} < p_X(x) \text{ then } d_{\text{HydroPump}} = C_{\text{HydroPump}} \text{ else } d_{\text{HydroPump}} = 0$$

Now the hydrogen storage content of hour x , $s_{\text{Hydro}}(x)$, is calculated:

$$s_{\text{Hydro}}(x) = s_{\text{Hydro}}(x-1) + w_{\text{Hydro}} - e_{\text{Hydro}} / \mu_{\text{Hydro}} + d_{\text{HydroPump}} * \alpha_{\text{HydroPump}}$$

If the storage content at hour x becomes negative, the model looks back from hour x to the nearest hour at which the storage was full, and identifies and deletes the hour of hydro power production with the lowest market price.

On the other hand, if the storage content at hour x exceeds the capacity of the storage, the model looks back from hour x to the nearest hour at which the storage was empty, and identifies and activates the hour of hydro production with the highest market price.

Due to differences in the storage content between the beginning and the end of the calculation period, errors may appear in the calculations. In order to correct these errors, the above calculation is repeated until the storage content at the end is the same as at the beginning.

7.8 Electricity Consumption of Heat Pumps and DH electrolysers

The following electricity production options are sorted according to the lowest marginal production costs:

- Nuclear
- Geothermal
- Condensing Power plants
- Individual N_{gas} CHP
- Individual Biomass CHP
- CHP replacing boilers in gr.2
- CHP replacing boilers in gr.3
- CHP replacing heat pumps in gr. 2
- CHP replacing heat pumps in gr. 3
- CHP replacing electrolysers in gr. 2
- CHP replacing electrolysers in gr. 3

Each option is then optimised according to market electricity prices starting with the option with the lowest marginal costs and taking into consideration the fact that each change in consumption influences the market price (decreases the market price).

Limitations in transmission lines are taken into consideration by setting a limit to the production of each unit so that the total export does not exceed the transmission capacity (if possible).

Limitations in import are calculated with regard to the condensing power plants, which will simply be activated in the case that the import transmission capacity is exceeded.

7.8.1 Nuclear

Nuclear is optimised in the following way: If the market price goes below the marginal production costs, the production is reduced.

The optimisation takes its starting point in the simple calculations of section 4.3.3 in which the production is simply determined by capacity and hour by hour distribution.

Then the system price, p_x , is calculated and the balance production of the nuclear power plant, $\text{BalanceProduction}_{\text{Nuclear}}$, is found as described in section 7.1.

If the balance production price is lower than the production found in section 4.3.3, the production is reduced accordingly.

7.8.2 Geothermal

Geothermal power is calculated in the same way as nuclear.

7.8.3 Condensing power plants

Condensing power production is optimised simply by identifying the system price, p_x , and the balance production of the condensing power plant, $\text{BalanceProduction}_{pp}$, as described in section 7.1.

$$e_{pp} = \text{BalanceProduction}_{pp}$$

The production is adjusted to the limit of zero and the power plant capacity, C_{pp} . If the net-import or export exceeds the transmission line capacity, the condensing power production is adjusted accordingly. In such case, the domestic and the external markets are separated and the marginal production cost on the condensing power plant determines the market price on the domestic electricity market.

7.8.4 Individual natural gas and biomass CHP

The individual natural gas and biomass CHP systems each consist of heat storage and three production units: Solar thermal, CHP and a peak load boiler. The peak load boiler is assumed to have the same thermal efficiency as the natural gas or the biomass boiler of the individual boiler systems.

First priority is given to solar thermal, and the model first identifies the maximum solar thermal output given the heat demand and the heat storage capacity. As part of the calculation, the model identifies the share of the heat storage which is occupied by solar thermal as a result of such operation.

The model now identifies the system price, p_x , and the balance production of the CHP system, $\text{BalanceProduction}_{M\text{-}Ngas\text{CHP}}$, as described in section 7.1. The electricity production of the CHP unit is found as the minimum of either the CHP capacity or balance production, which will influence the market price to such extent that it becomes equal to the minimum selling price.

$$e_{M\text{-}Ngas\text{CHP}} = \text{Min} (C_{M\text{-}Ngas\text{CHP}} , \text{BalanceProduction}_{M\text{-}Ngas\text{CHP}})$$

The heat storage content at hour x is calculated:

$$S_{M\text{-}Ngas\text{CHP}}(x) = S_{M\text{-}Ngas\text{CHP}}(x-1) - h_{M\text{-}Ngas\text{CHP}} - q_{\text{Solar-M-NgasCHP}} - q_{M\text{-}Ngas\text{CHP}}$$

If the heat storage content exceeds the capacity at hour x , the model looks back from hour x to the nearest hour at which the storage content (minus the share of the storage, which is occupied by solar thermal) becomes lower than the CHP heat production, and identifies the hour y , which has the lowest market price. The production at hour y is then decreased until the heat storage content at hour x does not exceed the capacity.

If, on the other hand, the heat storage at hour x goes below zero, then the boiler is activated.

Here, the optimisation procedure is shown for the natural gas CHP system. The same procedure is used for the biomass CHP system.

7.8.5 CHP replacing boilers in gr. 2 and 3.

CHP replacing boilers in district heating groups 2 and 3 is optimised by identifying the system price, p_x , and the balance production of the CHP plant, $\text{BalanceProduction}_{\text{CHP-B}}$, as described in section 7.1.

The balance production is added to the former production (if any) arising from CHP replacing either heat pumps or electrolysers as described in sections 7.8.6 and 7.8.7 below.

$$e_{\text{CHP}} = e_{\text{CHP}} + \text{BalanceProduction}_{\text{CHP-B}},$$

The production is adjusted to the limit of zero and the capacity C_{CHP} . If the net-import or export exceeds the transmission line capacity, the electricity production is adjusted accordingly in the same way as for the condensing power plant.

Then the heat storage is included in the calculation in the following way:

First, the corresponding heat production is found and the boiler is defined as zero:

$$q_{\text{CHP}} = e_{\text{CHP}} * \rho_{\text{CHP}} / \mu_{\text{CHP}}$$

$$q_{\text{B}} = 0$$

Then the heat storage s_{DH} content at hour x is calculated:

$$s_{\text{DH}}(x) = s_{\text{DH}}(x-1) - h_{\text{DH}} + q_{\text{Solar}} + q_{\text{Industry-DH}} + q_{\text{W}} + q_{\text{HP}} + q_{\text{Elc}} + q_{\text{CHP}} + q_{\text{B}}$$

Please, note that the solar thermal production is stored in its own low-temperature heat storage. The solar thermal production included above is the resulting output from the solar thermal and the low-temperature heat storage, which is included in the calculations together with the district heating demand in order to determine the net input/output to the high-temperature storage.

If the content of the heat storage at hour x becomes negative, then the boiler is activated:

$$\text{If } s_{\text{DH}} < 0 \text{ then } q_{\text{B}} = -s_{\text{DH}}$$

If the content of the heat storage at hour x exceeds the heat storage capacity, S_{DH} , then the model looks back from hour x to the nearest hour at which the storage content is lower than the CHP heat production at hour x , and identifies the hour y , which has the lowest market price. The production at hour y is then decreased until the heat storage content at hour x does not exceed the capacity.

The same procedure is used for each of the CHP units in district heating groups 2 and 3.

7.8.6 CHP replacing heat pumps in gr. 2 and 3.

CHP replacing heat pumps in district heating groups 2 and 3 is optimised by identifying the system price, p_x , and the balance production of the CHP plant, $\text{BalanceProduction}_{\text{CHP-HP}}$, as described in section 7.1. The balance production is added to the former production (if any) arising from CHP replacing either boilers or electrolysers, as described in sections 7.8.5 and 7.8.7.

$$e_{\text{CHP}} = e_{\text{CHP}} + \text{BalanceProduction}_{\text{CHP-HP}},$$

The production is adjusted to the limit of zero and the capacity C_{CHP} . If the net-import or export exceeds the transmission line capacity, the electricity production is adjusted accordingly in the same way as for the condensing power plant.

Then the corresponding heat production q_{DIFF} , which will replace the heat pump, is found:

$$q_{\text{DIFF}} = \text{BalanceProduction}_{\text{CHP-HP}} * \rho_{\text{CHP}} / \mu_{\text{CHP}}$$

If such production exceeds the heat pump heat production it is adjusted accordingly:

$$\mathbf{If} \ q_{\text{DIFF}} > q_{\text{HP}} \ \mathbf{then} \ q_{\text{DIFF}} = q_{\text{HP}}$$

Thereafter, the productions of the heat pump and the CHP unit are adjusted accordingly:

$$q_{\text{CHP}} = q_{\text{CHP}} + q_{\text{DIFF}}$$

$$q_{\text{HP}} = q_{\text{HP}} - q_{\text{DIFF}}$$

The heat storage is not included in the calculation since the heat production is the same. Heat pump production is just replaced by CHP.

The same procedure is used for each of the CHP units in district heating groups 2 and 3.

7.8.7 CHP replacing electrolysers in gr. 2 and 3

CHP replacing electrolysers in district heating groups 2 and 3 is optimised by identifying the system price, p_x , and the balance production of the CHP plant, $\text{BalanceProduction}_{\text{CHP-Elc}}$, as described in section 7.1. The balance production is added to the former production (if any) arising from CHP replacing either boilers or heat pumps as described in section 7.8.5 and 7.8.6.

$$e_{\text{CHP}} = e_{\text{CHP}} + \text{BalanceProduction}_{\text{CHP-Elc}}$$

The production is adjusted to the limit of zero and the capacity C_{CHP} . If the net-import or export exceeds the transmission line capacity, the electricity production is adjusted accordingly in the same way as for the condensing power plant.

Then the corresponding heat production, q_{DIFF} , which will replace the electrolyser is found:

$$q_{\text{DIFF}} = \text{BalanceProduction}_{\text{CHP-Elc}} * \rho_{\text{CHP}} / \mu_{\text{CHP}}$$

If such production exceeds the electrolyser heat production it is adjusted accordingly:

$$\mathbf{If} \ q_{\text{DIFF}} > q_{\text{Elc}} \ \mathbf{then} \ q_{\text{DIFF}} = q_{\text{Elc}}$$

Thereafter, the productions of the electrolyser and the CHP unit are adjusted accordingly:

$$q_{\text{CHP}} = q_{\text{CHP}} + q_{\text{DIFF}}$$

$$q_{\text{Elc}} = q_{\text{Elc}} - q_{\text{DIFF}}$$

The heat storage is not included in the calculation, since the heat production is the same. Electrolyser production is just replaced by CHP.

The same procedure is used for each of the CHP units in district heating groups 2 and 3.

7.9 Electricity storage (hydro or battery or CAES storage)

The model seeks to identify a realistic business-economic strategy of optimizing the net profit of buying and selling electricity on the basis of fluctuations in the market price and the variable operation including fuel costs in the case of CAES. The strategy is described in the CAES appendix as regulation strategy no. 4.

The strategy is based on a concept which takes the average price, $p_{Average}$, of an upcoming user-specified period (of y hours) and bid on the market correspondingly. The average price is found as:

	$i = x$	
$p_{Average}(x) =$	$\sum_{x+y} p(i)$	$/ (y)$

The bid on the market occurs in such way that the price difference between the buying and bidding prices is equally distributed around the average price. Figure 7.1 demonstrates this concept for a 24-hour period. The middle line represents the price average, $p_{Average}$, for the shown 24-hour period.

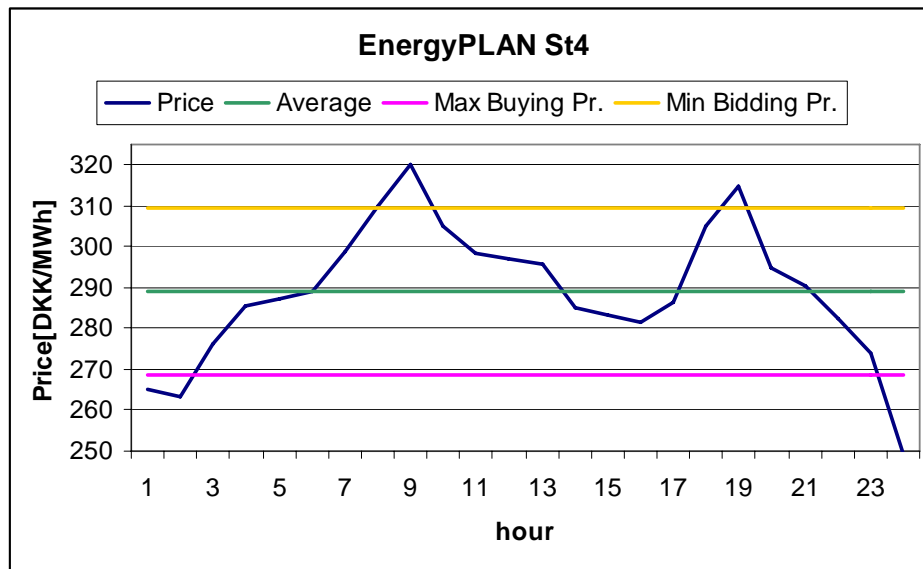


Figure 7.1: EnergyPLAN St4 concept, where the average of an upcoming period, 24 hours in this figure, is used for calculating market bidding prices.

The distance between the minimum and maximum lines represents the minimum difference between the selling and the buying price if a profit is to be made. Such price difference is identified on the basis of the multiplication and addition factors of CAES found in section 4.11.

$$F_{\text{Multiplication-CAES}} = 1 / (\alpha_{\text{pump}} * \mu_{\text{Turbine}})$$

$$F_{\text{Addition-CAES}} = (VOC_{\text{pump}} + TAX_{\text{pump}}) / (\alpha_{\text{pump}} * \mu_{\text{Turbine}}) + VOC_{\text{Turbine}} + \phi_{\text{CAES}} * (P_{\text{Ngas}} + P_{\text{Handling-Ngas}} + Tax_{\text{Ngas-CAES}}) * 3.6$$

The basic relation is that in order to generate a profit, the market price when selling must exceed the market price when buying, in accordance with the following formula of section 4.11:

$$p_{\text{sell}} > p_{\text{buy}} * F_{\text{Multiplication}} + F_{\text{Addition}}$$

In which p_{sell} is the market electricity price when selling (DKK/MWh)
 p_{buy} is the market electricity price when buying (DKK/MWh)
 $F_{\text{Multiplication}}$ is the multiplication factor (always bigger than 1), and
 F_{Addition} is the addition factor (DKK/MWh)

The price difference is defined as:

$$p_{\text{sell}} = p_{\text{Average}} + p_{\text{Diff}} \quad \text{and} \quad p_{\text{Buy}} = p_{\text{Average}} - p_{\text{Diff}}$$

And consequently the price difference can be identified as

$$p_{\text{diff}} = [p_{\text{Averager}} * (1 - \alpha_{\text{Pump}} * \mu_{\text{Turbine}}) + \text{constant}] / (\alpha_{\text{Pump}} * \mu_{\text{Turbine}} + 1)$$

In which the constant represents the variable operation costs of consuming one unit of electricity in the pump (or compressor), found as 1) the VOC on the pump, 2) the VOC on the turbine corrected for losses in the process, and 3) the VOC of the additional fuel in the turbine also corrected for the losses in the process:

$$\begin{aligned} \text{constant} = & (\text{VOC}_{\text{Pump}} + \text{TAX}_{\text{Pump}}) + \text{VOC}_{\text{Turbine}} * (\alpha_{\text{Pump}} * \mu_{\text{Turbine}}) \\ & + \phi_{\text{CAES}} * (P_{\text{Ngas}} + P_{\text{Handling-Ngas}} + \text{Tax}_{\text{Ngas-CAES}}) * 3.6 * (\alpha_{\text{Pump}} * \mu_{\text{Turbine}}) \end{aligned}$$

Based on the above price difference, p_{diff} , the operation of the electricity storage or CAES system is found in the following way:

The average price of the upcoming period is found as described and illustrated above and the minimum selling price and the maximum buying price are determined:

$$p_{\text{sell-Min}} = p_{\text{Average}} + p_{\text{Diff}}$$

$$p_{\text{Buy-Max}} = p_{\text{Average}} - p_{\text{Diff}}$$

The market system price, p_X , and the balance production of the turbine, $\text{BalanceProduction}_{\text{Turbine}}$, are found as described in section 7.1. If the market system price is higher than the minimum selling price the turbine is activated:

$$\text{If } p_X > p_{\text{sell-Min}} \text{ then } e_{\text{Turbine}} = \text{Min} (C_{\text{Turbine}}, \text{BalanceProduction}_{\text{Turbine}})$$

Similarly, the market system price is found for the pump, p_X , and the balance consumption of the pump, $\text{BalanceConsumption}_{\text{Pump}}$, as described in section 7.1. If the market system price is lower than the maximum buying price, the pump is activated:

$$\text{If } p_X < p_{\text{Buy-Max}} \text{ then } d_{\text{Pump}} = \text{Min} (C_{\text{Pump}}, \text{BalanceConsumption}_{\text{Pump}})$$

The storage content, s_{CAES} , is calculated:

$$s_{\text{CAES}}(x) = s_{\text{CAES}}(x-1) + d_{\text{Pump}} * \alpha_{\text{Pump}} - d_{\text{Turbine}} * \mu_{\text{Turbine}}$$

If the storage content exceeds the capacity, the pump is reduced accordingly and if the storage content goes below zero, the turbine production is reduced.

The above modelling makes it possible to bypass the storage while operating the pump and turbine at the same time, if feasible. Such situation occurs when operating a CAES plant as a gas turbine under conditions of high electricity prices and low natural gas prices.

Due to differences in the storage content between the beginning and the end of the calculation period, errors may appear in the calculations. In order to correct these errors, the above calculation is repeated until the storage content at the end is the same as at the beginning.

7.10 Resulting electricity market prices (External, Domestic and bottlenecks)

In the above mentioned procedure, it is checked for all production units if the balance production of each unit results in a total electricity production in the system, which will have the consequence that the export exceeds the transmission line capacity. If such a bottleneck occurs, the production of the relevant unit is reduced accordingly, as described in the procedure of section 7.8. Moreover, it is checked if the import exceeds the transmission line capacity, and in such case, the production on the condensing power plant is increased.

In the case of a bottleneck, the price areas of the external and the domestic market are separated, and the domestic market price is calculated as the highest bidding price of the active productions units, i.e. the marginal operation costs of the unit which created the bottleneck. In the case of critical excess production, the domestic market price becomes zero. The external market prices are calculated as shown in section 7.1, when applying an export equal to the capacity of the transmission lines.

If there is no bottleneck, the domestic and the external market prices are the same.

If bottlenecks occur, a profit is made since electricity is bought on one side of the bottleneck for a lower price than it is sold on the other side of the bottleneck. Such profit is normally shared on an equal basis between the TSOs on each side of the bottleneck. Consequently, half of such profit is here included as an income in the socio-economic feasibility calculation. Such income is found simply as 50% of the difference between the market prices on the domestic and the external markets.

7.11 Grid stability

In the end, the model makes sure that the grid stability requirements are fulfilled. First, the grid stabilisation is calculated as described in section 8.3 (below). If the requirement is not fulfilled the production on the power plant is increased accordingly.

8. Fuel, CO2 emission and Feasibility Study (calculations)

After having optimised the operation of the various productions units in accordance with either the technical or the market-economic optimisation strategy, the model makes a number of calculations of final fuel consumptions, CO2 emissions and costs. The model also removes critical excess electricity production in accordance with the specified strategy.

8.1 Fixed boiler production is added to the boilers in groups 2 and 3

The fixed boilers percentage of the district heating in groups 2 and 3, subtracted in section 5.4, is now added to the boiler production. The fixed boilers percentage represents the hours in which the CHP units of one system are not operating because of maintenance or breakdowns

$$q_{B2} = q_{B2} + q_{\text{FixedBoiler2}}$$

The same calculation is done for district heating group 3.

8.2. Reducing Critical Excess Electricity Production

A number of measures to reduce Critical Excess Electricity Production, e_{CEEP} , can be activated as shown in section 4.13:

- 1: Reducing RES1 and RES2
- 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.
- 6: Reducing RES4 and RES5
- 7: Reducing power plant in combination with RES1, RES2, RES3 and RES4

It is possible to specify one or more numbers, which will be treated in the specified order. For example, the combination 315 activates three CEEP reductions. First, CEEP is reduced as much as possible by option 3, then by option 1 and finally by option 5. All 7 options can be activated in all possible combinations.

8.2.1 Reducing RES1 and RES2

First, RES1 is reduced. The reduction potential, Red_{pont} , is found as follows:

$$\text{Red}_{\text{pont}} = \text{Min}(e_{\text{RES1}} ; e_{\text{CEEP}})$$

And new values are calculated:

$$e_{\text{RES1}} = e_{\text{RES1}} - \text{Red}_{\text{pont}}$$

$$e_{\text{CEEP}} = e_{\text{CEEP}} - \text{Red}_{\text{pont}}$$

RES 2 production is thereafter calculated in the same manner.

8.2.2 Reducing CHP production in group 2

First, the minimum CHP production needed in order to fulfil the requirement of stabilising the grid is found:

$$e_{\text{CHP2-Min}} = [e_{\text{Total}} * \text{Stab}_{\text{total}} - e_{\text{RES1}} * \text{Stab}_{\text{RES1}} - e_{\text{RES2}} * \text{Stab}_{\text{RES2}} - e_{\text{RES3}} * \text{Stab}_{\text{RES3}} - e_{\text{RES4}} * \text{Stab}_{\text{RES4}} - e_{\text{CHP3}} - e_{\text{Nuclear}} - e_{\text{Hydro}} - e_{\text{PP}} * (1 - \text{Stab}_{\text{Total}})] / \text{Stab}_{\text{CHP2}}$$

Then the reduction potential, Red_{pont} , is found:

$$Red_{pont} = \min(e_{CHP2} - e_{CHP2-Min} ; e_{CEEP})$$

And new values are calculated:

$$e_{CHP2} = e_{CHP2} - Red_{pont}$$

$$e_{CEEP} = e_{CEEP} - Red_{pont}$$

$$q_{CHP2} = e_{CHP2} * \rho_{CHP2} / \mu_{CHP2}$$

$$q_{B2} = q_{B2} - Red_{pont2} * \rho_{CHP2} / \mu_{CHP2}$$

8.2.3 Reducing CHP production in group 3

First, the minimum CHP production needed in order to fulfil the requirement of stabilising the grid is found:

$$e_{CHP3-Min} = [e_{Total} * Stab_{total} - e_{RES1} * Stab_{RES1} - e_{RES2} * Stab_{RES2} - e_{RES3} * Stab_{RES3} - e_{RES4} * Stab_{RES4} - e_{CHP2} * Stab_{CHP2} - e_{Nuclear} - e_{Hydro} - e_{PP} * (1 - Stab_{Total})] / Stab_{CHP2}$$

If such minimum is below the input-specified CHP3 minimum production, $C_{CHP3-Min}$ (see section 4.13), the value is increased accordingly:

$$\text{If } e_{CHP3-Min} < C_{CHP3-Min} \text{ then } e_{CHP3-Min} = C_{CHP3-Min}$$

Then the reduction potential, Red_{pont} , is found:

$$Red_{pont} = \min(e_{CHP3} - e_{CHP3-Min} ; e_{CEEP})$$

And new values of CHP and boiler heat production are calculated as in section 8.2.2 above.

8.2.4 Replacing boiler production with electric heating in group 2

The reduction potential, Red_{pont} , is calculated as follows:

$$Red_{pont} = \min(q_{B2} ; e_{CEEP})$$

Then the value for electric heating is calculated

$$e_{EH} = Red_{pont}$$

Subsequently, new values for e_{CEEP} and q_{B2} are calculated.

8.2.5 Replacing boiler production with electric heating in group 3

The same calculations are made as described in section 8.2.4 above, just replacing group 2 with group 3.

8.2.6 Reducing RES3

The potential of reducing RES3 is found in the same way as for RES1 in section 8.2.1 above.

8.2.7 Reducing power plant production in combination with RES1, RES2, RES3 and RES4

This option has been added because in options 1 and 6 (reduction of RES1, RES2 and RES3), the sequence of first increasing the power plant for stability reasons and then decreasing renewable sources in cases of very high RES shares led to CEEP from the power station instead. In such cases, one can increase the share of RES and still maintain minimum stabilisation demands by decreasing the power plant and the RES productions simultaneously.

First, the minimum load of the power plant is calculated in the case of no RES1 at all:

$$e_{PP-No-RES1} = [e_{Total} * Stab_{total} - e_{Res2} * Stab_{Res2} - e_{Res3} * Stab_{Res3} - e_{Res4} * Stab_{Res4} - e_{CHP2} * Stab_{CHP2} - e_{CHP3} - e_{Turbine}] / (1 - Stab_{total})$$

Then, the reduction potential of the power plant is found as the difference between this number and the previously found electricity production of the power plant:

$$e_{PP-pontial} = e_{PP} - e_{PP-No-Res1}$$

The potential reduction of CEEP achieved through this reduction of the power plant is identified by the following factor:

$$factor = e_{CEEP} * (Stab_{Total} - Stab_{Res1}) / (1 - Stab_{Res1})$$

If such factor is lower than the reduction potential, $e_{PP-pontial}$, the reduction potential is reduced accordingly:

$$\text{If } e_{PP-pontial} > factor \text{ then } e_{PP-pontial} = factor$$

First, the CCEP is reduced by the power plant contribution:

$$e_{pp} = e_{pp} - Red_{pont}$$

$$e_{CEEP} = e_{CEEP} - Red_{pont}$$

Then a new reduction potential achieved by reducing RES1 is found and CEEP and RES1 are reduced accordingly:

$$Red_{pont-next} = \text{Min}(e_{RES1} ; e_{CEEP})$$

$$e_{RES1} = e_{RES1} - Red_{pont-next}$$

$$e_{CEEP} = e_{CEEP} - Red_{pont-next}$$

The same procedure is repeated for RES2, RES3 and RES4.

8.3 Grid stabilisation

The degree to which the grid stabilisation requirements have been fulfilled is calculated in the following way:

First, the grid stabilisation demand, d_{Stab} , is calculated on the basis of e_{Total} , which represents all electricity productions as described in section 6.1:

$$d_{Stab} = e_{Total} * Stab_{total}$$

Then the grid stabilisation supply, e_{Stab} , is calculated:

$$e_{\text{Stab}} = e_{\text{PP}} + e_{\text{CHP2}} * \text{Stab}_{\text{CHP2}} - e_{\text{RES1}} * \text{Stab}_{\text{RES1}} - e_{\text{RES2}} * \text{Stab}_{\text{RES2}} - e_{\text{RES3}} * \text{Stab}_{\text{RES3}} \\ - e_{\text{RES4}} * \text{Stab}_{\text{RES4}} - e_{\text{CHP3}} - e_{\text{Nuclear}} - e_{\text{Hydro}} - e_{\text{V2G}}$$

Then the fulfilment of the grid stabilisation, GridStab , is calculated en per cent:

$$\text{GridStab} = e_{\text{Stab}} / d_{\text{Stab}} * 100$$

8.4 Heat balances in district heating systems

Then the heat balances, h_{Balance} , in the district heating groups are calculated:

$$h_{\text{Balance}} = h_{\text{DH}} - h_{\text{Solar}} - h_{\text{CSHP}} - h_{\text{CHP}} - h_{\text{HP}} - h_{\text{B}} - h_{\text{EH}} - h_{\text{Elc}}$$

The heat balance is calculated separately for each district heating group.

8.5. Fuel consumptions

For various production units in the model (DHP, CHP2, CHP3, Boiler2, Boiler3 and PP), the distribution on fuel types is stated as input (See section 4.10) divided into the following types of fuels:

- Coal
- Oil
- Natural Gas, and
- Biomass

For transportation, oil is divided into fuel oil, Diesel/Gas oil and Petrol/JP. Moreover, fuels such as hydrogen (or similar fuels from internal energy conversion as part of the system) are calculated.

For the production units mentioned above, the distribution is calculated relatively. The total fuel consumption of each energy unit is the result of the system analyses described in chapters 6 and 7. 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: Coal=2, Oil=2, Ngas=4, Biomass=2, Total=10.

The model can be told not to consider limitations in some of the fuel types by activating the "Variable / Fixed" button in the 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: Coal=2.25, Oil=2.25, Ngas=4.5, Biomass=1, Total=10.

If **all** buttons are activated as "fixed", the model is told to consider all types 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 new type of fuel named "Renewable"

8.6 CO2 emissions

Given the CO2 emission (kg/GJ) for each of the four fuel types as an input, the model calculates the CO2 emission simply by multiplying the fuel consumption by the emission data.

The model also calculates an import/export-corrected CO2 emission by using the import/export-corrected fuel account.

8.7 Share of Renewable Energy

The model calculates the share of renewable energy in the system. The share is calculated as a percentage of the primary energy supply. The renewable resource is found as RES, Hydro Power, Geothermal power and solar thermal productions plus biomass and waste fuels. The total primary energy supply is found as the same number plus all fossil fuels. Fuel such as hydrogen or biofuel for transportation produced on waste is not included in the primary energy supply, since they are produced on other energy resources which have already been included in the supply.

The model also calculates the share of electricity produced on renewable energy. In such calculation, the share of biomass compared to the total fuel consumption determines the share of CHP and power plants.

8.8 Cost

Annual socio-economic costs are divided into fuel costs, variable and fixed operation and maintenance costs, investments costs, CO2 emission costs and electricity exchange costs.

8.8.1 Fuel costs

Fuel costs are defined as input unit prices including handling costs multiplied by the annual total fuel consumption. The socio-economic costs do not include taxes.

The total annual coal costs, A_{Coal} , are found as follows:

$$A_{\text{coal}} = 3.6 * [F_{\text{Coal-Total}} * P_{\text{Coal-WM}} + F_{\text{Coal-PP}} * P_{\text{Coal-HCen}} + (F_{\text{Coal-B1}} + F_{\text{Coal-CHP2}} + F_{\text{Coal-CHP3}} + F_{\text{Coal-B2}} + F_{\text{Coal-B3}} + F_{\text{Coal-CSHP}}) * P_{\text{Coal-HDec}} + F_{\text{Coal-Indv}} * P_{\text{Coal-HIndv}}]$$

The costs of the other fuels are found in the same way.

8.8.2 Electricity exchange costs

Electricity exchange costs are found on the basis of resulting external market prices, see e.g. section 7.10. Import costs are found as the hourly import multiplied by the resulting external market price of the relevant hour. Income from export is found in the same way.

The exchange cost of fixed import export is found in the same way as the import/export costs multiplied by external market prices.

Bottleneck income is found as described in section 7.10 as half of the difference between external and domestic market prices multiplied by the transmission capacity, since bottlenecks only appear when the transmission capacity is fully exploited.

8.8.3 Variable operation costs

The annual variable operation costs are found as the cost per unit (of section 4.11) multiplied by the relevant production. E.g. the operation costs of boilers are found in the following way:

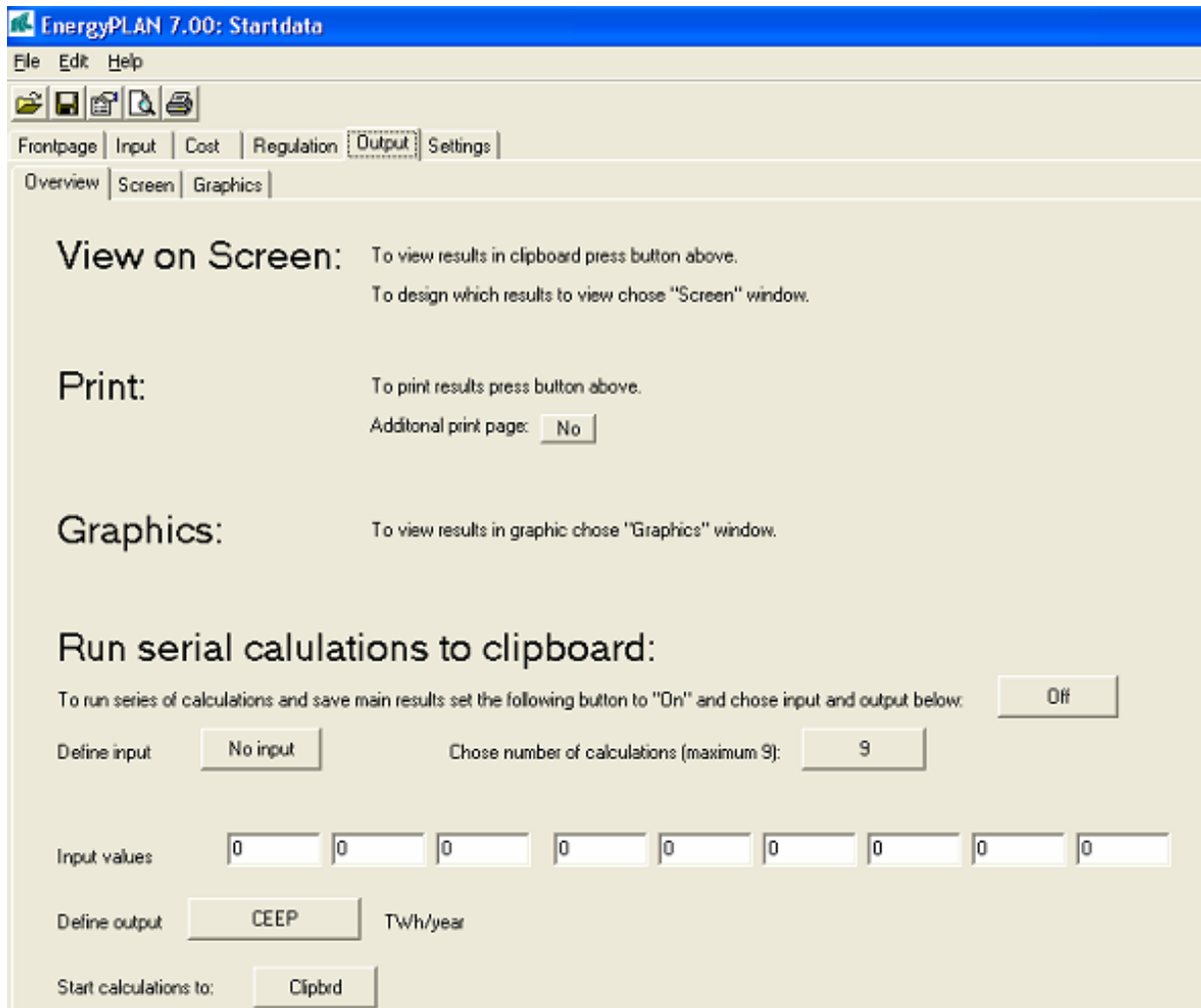
$$A_{\text{VOC-Boiler-DH}} = (e_{B1} + e_{B2} + e_{B3}) * P_{\text{VOC-Boiler-DH}}$$

8.8.4 Fixed operation and maintenance and investment costs

The fixed operation and maintenance costs as well as the annual investment costs are found already in the investment/cost window (see section 4.12).

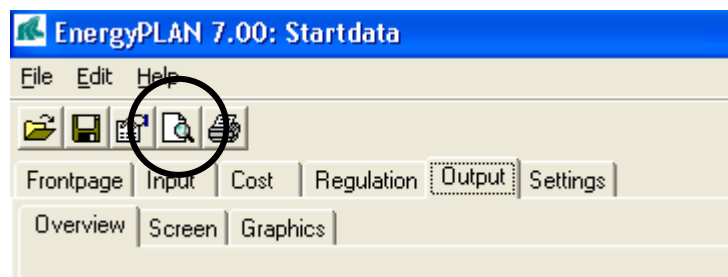
9. Output

The output can be shown and/or exported from the model in the following ways: View on the screen, Print or seen in Graphics.

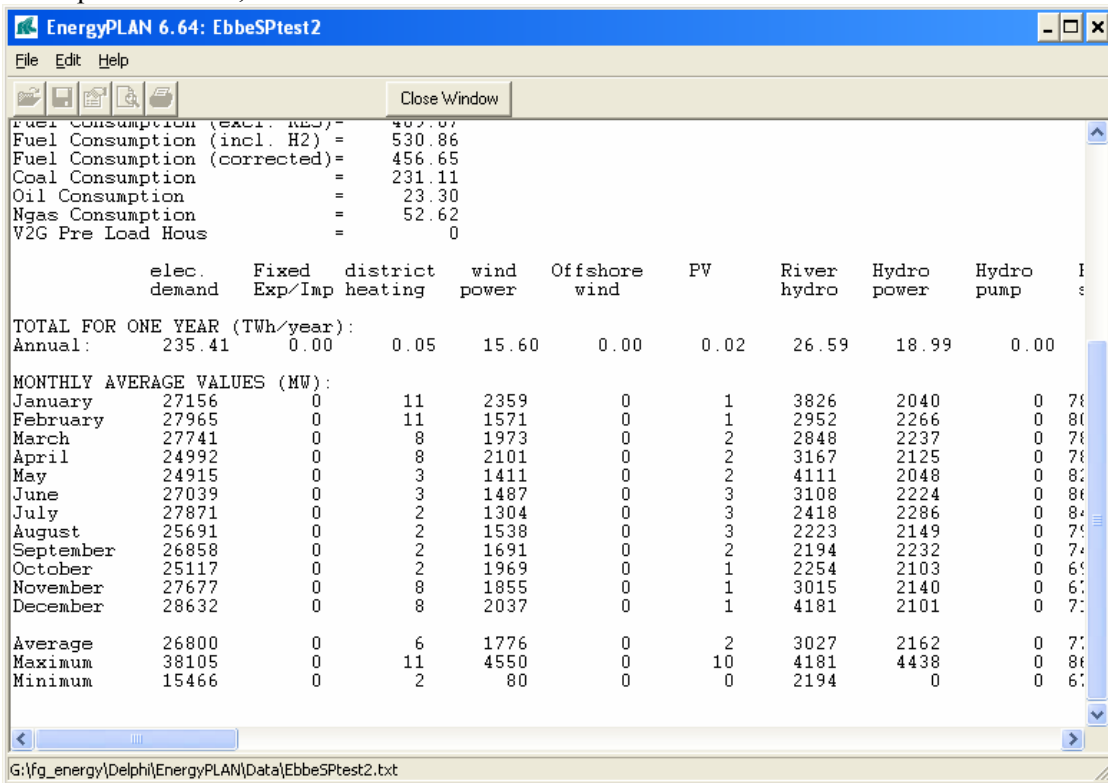


9.1 The screen function

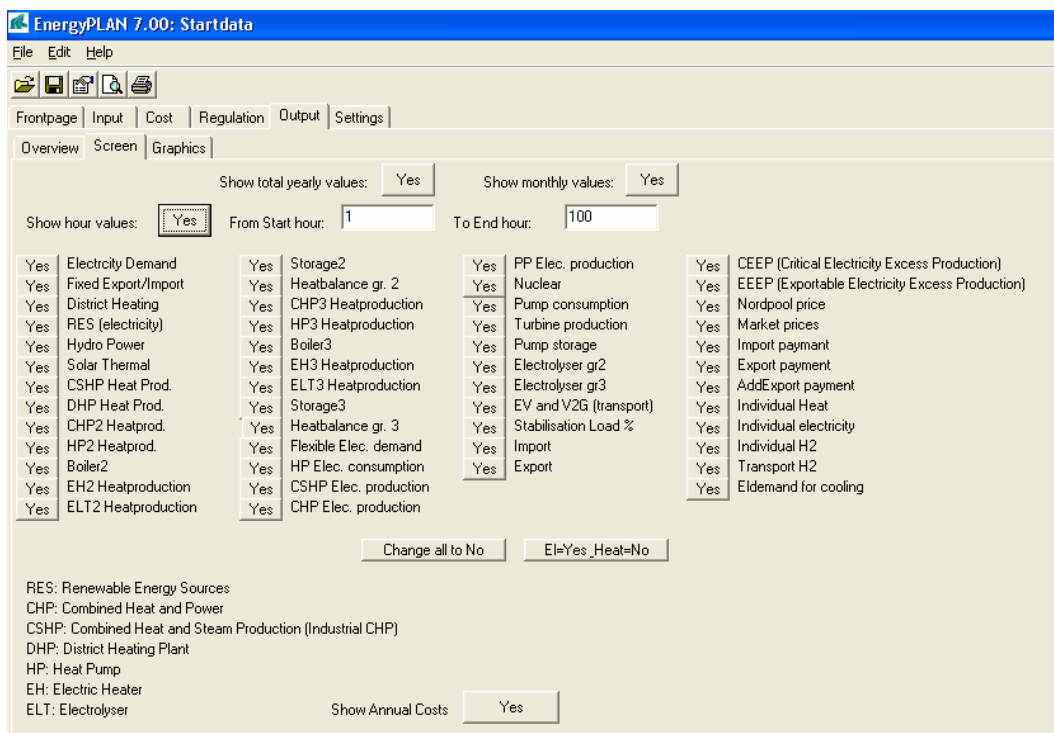
Results can be viewed on the screen.



The function can be activated in the upper line of the main display of the programme by clicking on the icon called "view clipboard". When activating this facility, the programme will start calculating and then open a text file, in which the results are shown.

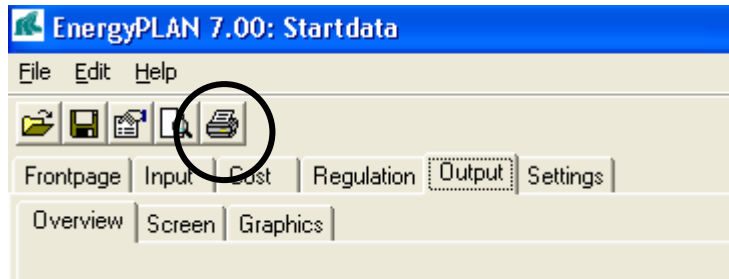


All calculated results of each unit in the system can be shown both on an annual and a monthly basis. Moreover, one can see each hour by hour value. The user can define the results to be shown in the "Screen" window in the EnergyPLAN model. All hour by hour data for all calculations are available.



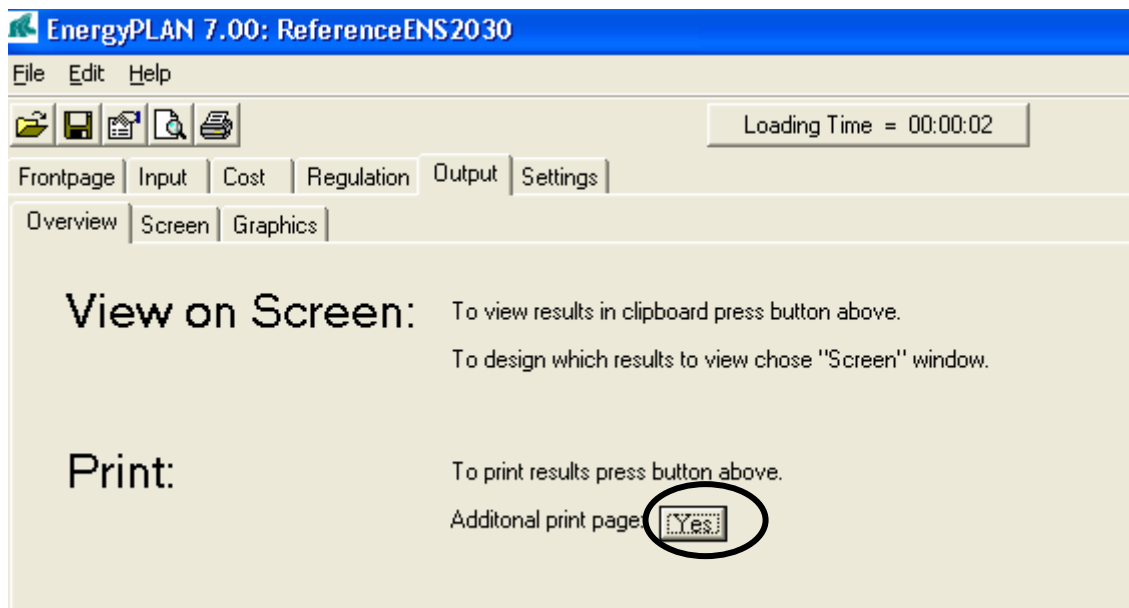
9.2 The print

Results can be printed in an A4 version defined by the model.



The function can be activated in the upper line of the main display of the programme by clicking the printer icon. When activating this facility, the programme will start calculating and then send a print to the printer.

One can choose to add an additional page of specifications by clicking on "Yes" in the output overview window as shown below. In such case, two pages will be printed in stead of one.



Examples of prints are shown on the next page.

9.3 Graphics

Results can be shown graphically and exported by the clipboard function

By activating the "Graphics" window, the results are illustrated graphically using the hour by hour values.

Three choices are offered by activating the buttons in the lower left corner: the electricity balance, the district heating balance, and the flexible electricity demand. Three diagrams are shown for each of the items.

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 as 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 clicking on the "clipboard" button located in the upper right corner of each diagram.

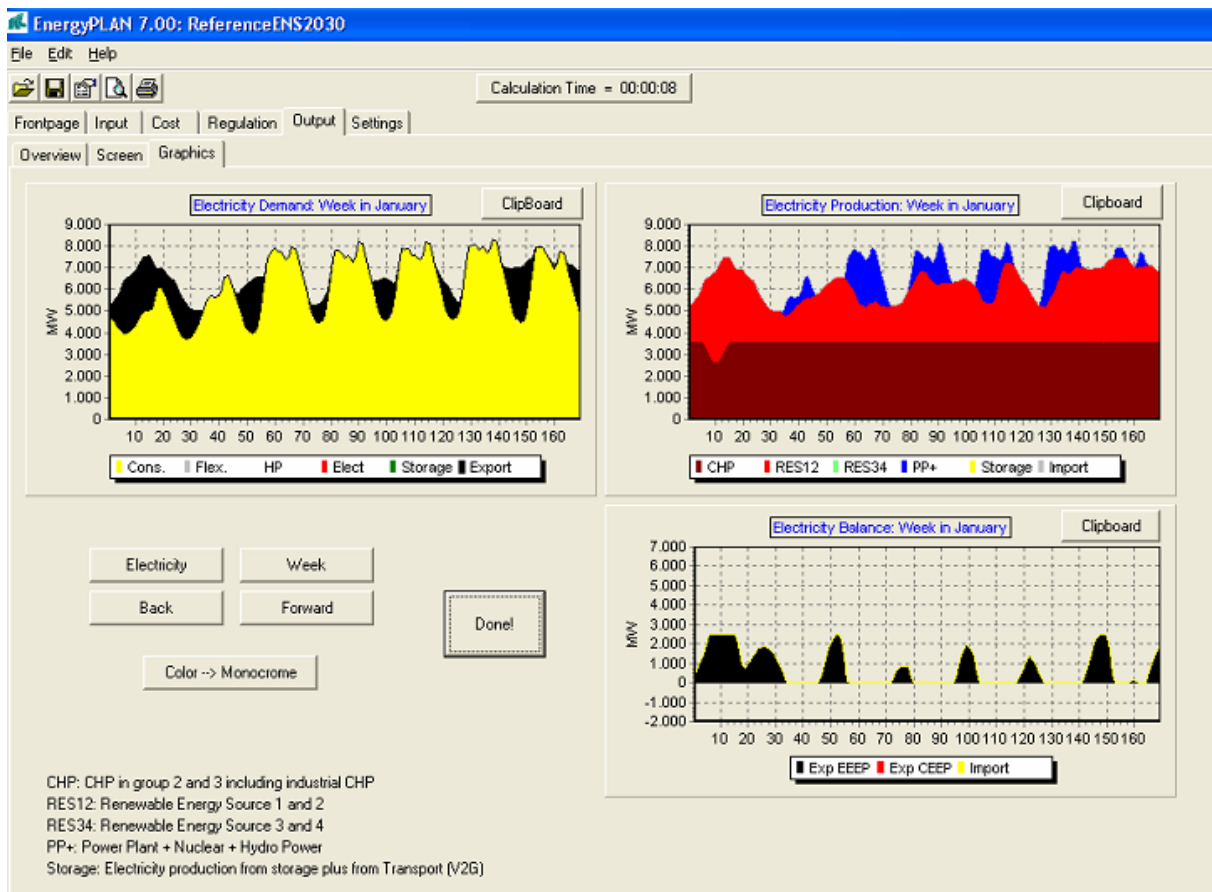


Diagram 6: Example of graphical presentations of results

9.4 Run serial calculations function

Run serial calculations to clipboard:

To run series of calculations and save main results set the following button to "On" and chose input and output below:

Define input Chose number of calculations (maximum 9):

Input values

Define output TWh/year

Start calculations to:

Start calculations to:

Moreover, the output window makes it possible to run series of up to 9 calculations by activating the "Run series calculations". The calculations are started by activating either the "Clipbrd" or the "Ascii" buttons. In the first case, the results are put into the clipboard and can be loaded into any Windows program such as Word or Excel by the Ctrl+V function.

Before starting the series calculations, one has to

- define which input parameters are to be changed by activating the "Define input" button
- define how many calculations are to be carried out by activating the "series number" button
- define a value of each input by writing inputs in the "input values" column, and
- define which output parameter one wants to save in the Clipbrd/Ascii function by activating the "define output" button.

9.5 Export Screen Data to Clipboard and e.g. EXCEL

The same results which are shown in the screen function (defined by the user as described in section 9.1) can also be exported to the clipboard and thereby be loaded into e.g. EXCEL.

This is simply done by setting the run serial button to "Off" and activating the clipboard function in the Output overview window:

Run serial calculations to clipboard:

To run series of calculations and save main results set the following button to "On" and chose input and output below:

Define input Chose number of calculations (maximum 9):

Input values

Define output TWh/year

Start calculations to:

Appendix: CAES Market Optimization

By Georges Salgi (14/08/06)

This manual documents three of the main spot market operation strategies for an electricity storage plant such as CAES in the EnergyPLAN model:

- Strategy 6, which is based on a deterministic annual time series, and is considered to generate the highest possible annual operational profit;
- Strategy 5, based on the ability to project electricity prices for up to 24 hours;
- Strategy 4 which is based on the assumption that the average price for the coming 24 hours is the same as that of the last 24 hours.

Strategy 6 is thus aimed at finding the “theoretical” optimum operation of the electricity storage plant given the annual electricity price time series. Strategies 4 and 5, on the other hand, reflect a “practical” operational mode with the operator having limited knowledge on future market conditions.

Electricity Storage Input/Output Window

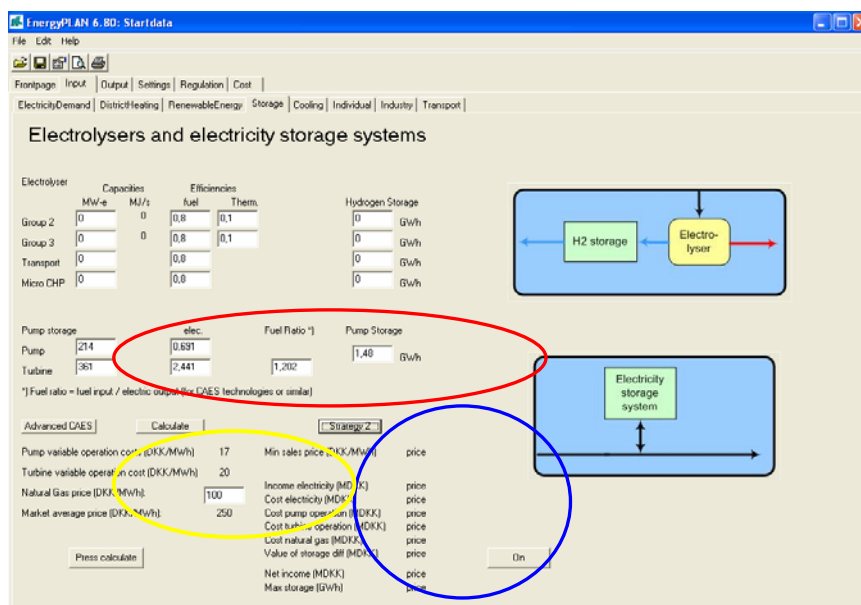


Figure 1: EnergyPLAN electricity storage main Input/Output window

Figure 1 shows a caption of the main electricity storage Input/Output window. This window can be accessed by entering the Input and Storage tabs at the top of the window. While the upper part of the window is concerned with electrolysers for hydrogen generation, the lower part is used for electricity storage applications.

The main technical input variables can be defined in the area marked in red in Figure 1. In order to accommodate storage/generation hybrid technologies such as CAES, the input includes fuel consumption during electricity generation. The main required inputs in this area are:

- Pump capacity, where pump is the term used to represent the technology that converts electric power into stored power and could be, for example, a rechargeable battery or a compressor.

- Turbine capacity, where turbine is the term used to represent the technology that converts stored power into electricity, which could be, for example, a battery or a turbine.
- Pump efficiency when converting the electric energy to stored energy
- Turbine efficiency when converting stored energy to electric energy. In technologies such as CAES, this efficiency can be greater than 1 due to fuel addition.
- Fuel Ratio, which is the ratio of the fuel energy added per unit of electricity produced:

$$Fuel\ Ratio = \frac{Fuel\ input}{Electricity\ output} \dots\dots\dots[1]$$

- Storage capacity, which is the net amount of storage capacity in GWh.

The main financial inputs are shown in the lower-left area marked in yellow in Figure 1. Apart from the fuel cost, the other inputs are imported from other windows. The pump and turbine operational costs reflect the variable entered in the Cost and Operation tabs, whereas the average electricity price reflects the average of the price time series entered in the Regulation tab.

Finally, main output operational results are shown in the lower right corner of Figure 1 marked in blue. These results include electricity consumption and production costs, operational costs, fuel costs, the net income, and the maximum utilized storage capacity. Besides, certain strategy-specific variables are entered in the box above this area. For example, the maximum number of iterations in strategy 6 and the projected period in strategy 4 are entered in this area.

Strategy 4

The idea of this model is to take the average price of an upcoming user-specified period and bid on the market correspondingly. The bid on the market occurs in such way that the price difference between the buying and bidding prices is equally distributed around the average price. Figure 6 demonstrates this concept for a 24-hour period. The green line represents the price average for the shown 24-hour period. Based on that, the distance to the two other lines is calculated.

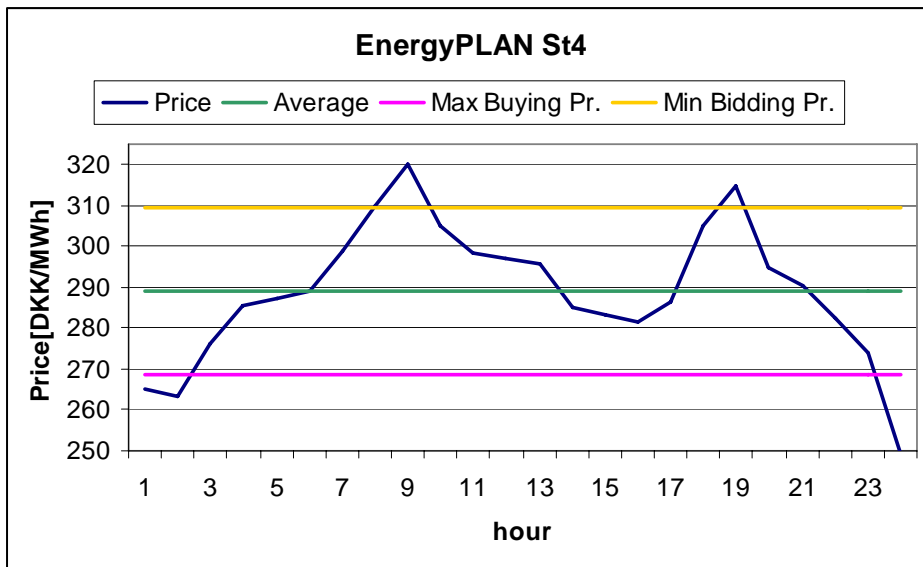


Figure 2: EnergyPLAN St4 concept, where the average price of an upcoming period, 24 hours in this figure, is used to calculate the market bidding prices.

The distance between the minimum/maximum lines and the average price can be calculated analytically using the following equation:

$$M.C._{(\bar{P}-\Delta P)} = \bar{P} + \Delta P \dots\dots\dots[2]$$

Where:

\bar{P} is the average price over the given period

ΔP is the price difference from the average price

$M.C._{(\bar{P}-\Delta P)}$ is the marginal production cost for an electricity unit bought at the price $\bar{P} - \Delta P$

The marginal cost can be expressed as:

$$M.C._{(\bar{P}-\Delta P)} = \frac{[(\bar{P} - \Delta P) + K]}{\eta_c \eta_T} \dots\dots\dots[3]$$

Where

η_c is the compressor efficiency

η_T is the turbine storage efficiency defined as the power output per unit storage energy input.

K is a constant that includes the variable operational costs and fuel costs:

$$K = O.C.c + \eta_c \eta_T (F.R. \cdot N.Gas.Price + O.C.T) \dots\dots\dots[4]$$

O.C.c is the compressor operational cost

O.C.T is the turbine operational cost

F.R. is the fuel ratio

Substituting (2) and (3) in (1) leads to the following relation:

$$\Delta P = \frac{\bar{P}(1 - \eta_c \eta_T) + K}{1 + \eta_c \eta_T} \dots\dots\dots[5]$$

In the above calculation, bypassing the storage while operating the pump and turbine at the same time is not allowed. There are, however, hours when this could be feasible, such as when operating a CAES plant as a gas turbine. To account for this, the first step can be calculated by pressing the lower left button and calculate “trin1”. This step goes through the strategy 4 results and allows the compressor and turbine to operate during the same hour when this feasible and when the storage content is empty.

Strategy 5

Strategy 5 is similar to strategy 4 with the exception that strategy 5 takes the price average of a user-specified previous period and uses it as the basis for determining the bidding strategy of the upcoming period.

Strategy 6

Strategy 6 is aimed at finding the maximum theoretical operational income given a deterministic annual electricity prices time series. The algorithm can be summarized in 7 main steps:

1. Identify the maximum electricity price in the “Turbine prices” time series, which is initialized as a copy of the original electricity prices time series. In this “Turbine prices” time series, hours at which the full turbine capacity is operating or with no potential profit are given a low negative value in order to avoid their reselection in later iterations.
2. Identify the storage boundaries around the maximum price. In this step, the hours prior to and after the maximum price hour are examined. The first hour in the backward range following an hour with full storage is considered as the “range start”, whereas the first hour with an empty storage in the forward range is considered as the “range end”. This range constitutes the time space in which recharging/discharging is possible. The range can very well constitute only the maximum price hour, in which case the plant would operate in the bypass mode.
3. Identify the minimum electricity price within the range defined in step 2.
4. Calculate the marginal operating cost (MC) based on the minimum price found in step 3. The MC is calculated according to equation [3] presented in Strategy 4, where $(P - \Delta P)$ is replaced by the minimum electricity price. If the maximum electricity price found in step 1 is greater than the MC, the calculation proceeds to step 5. Otherwise, the price in the “Turbine prices” time series is set to a low negative value to avoid its reselection.
5. Determine the “operation bottleneck” in the range between the maximum and minimum prices. This bottleneck is the minimum of the following 3 main variables:
 - Available unutilized turbine capacity at the maximum price hour
 - Available unutilized pump capacity at the minimum price hour
 - Storage bottleneck which is:
 - The minimum free storage space in case the pumping hour lies before the turbine hour
 - The minimum storage content in case the pumping hour lies after the turbine hour.
6. Operate the turbine during the hour of maximum price and the compressor during the hour of minimum price by the capacity determined in step 5 and update the storage content. In case the turbine has reached its full capacity at the mentioned hour, set the price in the “Turbine prices” series to a low negative value to avoid its reselection. In case the pump has reached its full capacity, set the hour price in the “Compressor prices” time series to a high positive value to avoid its reselection.
7. Iterate back to step 1 until the iteration limit is reached