

EUSUSTEL

European Sustainable Electricity; Comprehensive Analysis of Future European Demand and Generation of European Electricity and its Security of Supply

WORK PACKAGE 3

Electricity Generation Technologies and System Integration

Subtask 3.4.2

**Greenhouse-gas emissions due to interaction centralised
and decentralised generation (because of operation-time
effects and investment consequences)**

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1. Introduction

When analysing the CO₂-emissions of electricity generation plants, one must not only focus on the emissions of the different power plants as individual units. Power plants do not always operate in rated conditions, but interact with the other units of the electricity generation system (henceforth referred to as “park”). The park normally consists of different types of power plants, nuclear plants, CCGT’s, coal-fired plants, hydro plants, cogeneration units, wind farms, etc.

As the electricity demand is changing constantly through the day, between day/night, between week and weekend day and between the seasons, and as electricity is hardly storable, the electricity production has to adapt constantly to the demand. Power plants are activated to produce electricity, based on marginal costs. This marginal production cost is mainly depending of the fuel prices and the power-plant efficiencies. Besides those two parameters, the minimum start-up time, the minimum load and the possible variation in load are important as well. As a consequence, the production mix and the related fuel mix vary constantly, and so are the CO₂-emissions. As an example, for the Belgian electricity market, a dynamic production mix simulation tool “PROMIX” has been developed. Currently that model is being extended to cover Germany, The Netherlands and France as well. This is more elaborated in section 2.

Section 3 deals more in detail with the impact of cogeneration on the overall CO₂-emissions of the electricity generation park. A dynamic and integrated approach is presented. Three examples compare the results of the static method with the PROMIX-simulation results: industrial cogeneration; cogeneration in the commercial sector and massive implementation of cogeneration for residential heating.

It is important to mention that all analyses hereunder have been done under the condition of low gas prices (situation end of nineties). Nowadays, those low gas prices are not valid any more, which influences the start-up order. High efficient coal-fired plants become more important. Absolute results of the simulations do change, but anyhow, the methodology and the systematic approach and the resulting consequences, as discussed below, remain valid, even though price structure has changed. Indeed, sensitivity analyses on fuel prices have shown that the major qualitative conclusions remain unchanged.

Besides that, all PROMIX simulation results are based on the Belgian situation. But the nature of the presented analysis is so, that the results and methodology can be extrapolated to a larger European scale.

2. CO₂-emissions of the global electricity generation park

2.1. Modelling of the electricity generation

To determine the overall mean CO₂-emissions due to electricity production, it is important to know the starting order of the different power plants. First of all, there are the “must-run” units such as renewable energy sources, the cogeneration plants and the power plants, which make use of industrial gases (e.g. blast furnace gases). Secondly, there are the typical base load plants like the nuclear plants and under the assumption of low gas prices the (best performing) CCGT-plants. And after that, in varying order, depending on type of power plant: modern and efficient coal-fired plants, older CCGT-units, older coal- and gas-fired plants, gas turbines and pumping units. Besides that, there is the import and export market.

Figure 1 and Figure 2 show diagrams resulting from a typical PROMIX-simulation. Figure 1 shows the electricity generation for 2005. Figure 2 shows the corresponding emissions (GHG's, SO_x and NO_x). Every diagram is the visual representation of a 52 by 168 matrix. On the horizontal axis the week is plotted from left (Monday morning) to right (Sunday night); 168 values per week. On the vertical axis the year is run through from top (January 1) to bottom (December 31); 52 weeks per year.

2.1.1. Electricity generation

In Figure 1, the top diagram shows the overall electricity generation of the entire power system (dark = full power; white = zero power). The following diagrams show the power generation for specific types of power plants: nuclear plants, cogeneration plants, combined cycle plants (CC gas in the figures), coal-fired plants and finally, oil-fired plants (the output of other plants is also modelled, but not shown). Dark parts represent periods where the plants are highly utilised.

The nuclear power plants dominate the electricity generation because they continuously operate in base load. This is clearly demonstrated in Figure 1; there are no fluctuations in the production. The horizontal bright lines in the middle of the year are caused by planned outages.

Also, the cogeneration plants, renewable power stations and units operating on blast furnace gas are operated as "must-run" units and are therefore highly utilised (more precisely, whenever they are running – e.g., wind turbines – the power delivered is bought and appears as "must-run"). However, their share in the total electricity generation is modest because of the small amount of installed power. In Figure 1, only the cogeneration plants are shown. The cogeneration plants are divided into two groups, depending on what kind of industry they are related to. The first group is continuously operating. The second group of plants only operates during "business hours"; namely only during the daytime of weekdays.

The load diagrams of renewables and units on blast furnace gas are not shown because they look similar to the load diagram of the nuclear power plants. To be more precise, for renewables also a stochastic component should be added to simulate the variation of the wind speed.

Because of the "take-or-pay" gas contracts in Belgium, combined cycle plants can also be considered base load plants, and are also highly utilised¹. Figure 1 shows that combined cycle plants are at full power during winter weekdays and -nights and are only reduced in power during weekends and summer nights.

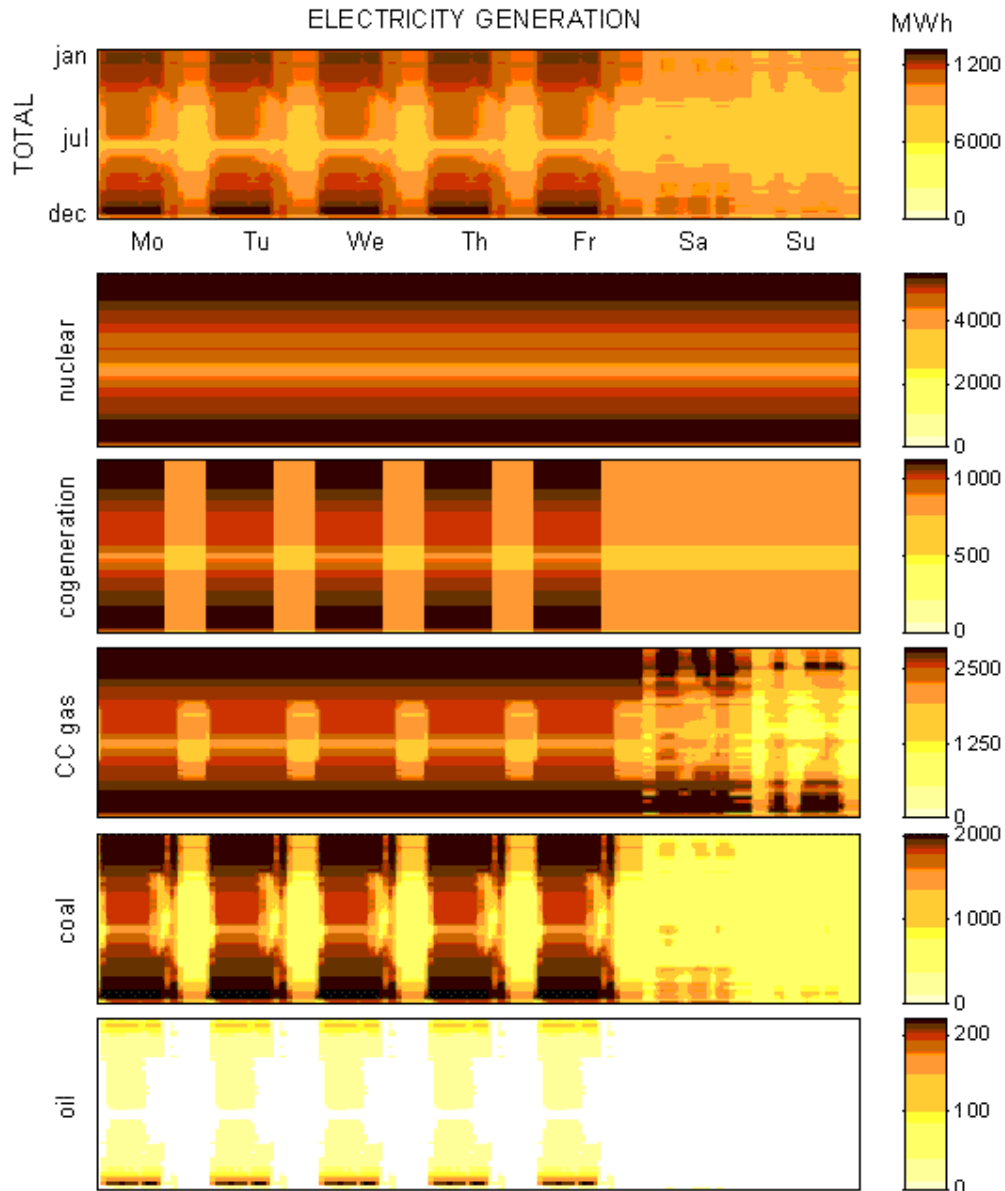


Figure 1 Electricity generation per hour and per type of power plant; PROMIX-results for 2005

Still according to the fuel-price assumption, coal-fired plants are what we call "semi-base load" power plants. In Figure 1 it is obvious that coal-fired plants only operate at full power when

¹ As a matter of fact, in a liberalised market, this is merely an assumption since generators may well opt to sell gas on the exchange rather than use it to produce electricity. If available, they would then use coal to produce electricity.

demand is extremely high: in winter during the daytime. At night and during weekends, coal-fired plants operate at much lower regimes.

Some of the natural gas and most of the oil-fired plants are "peak-power plants". Therefore, their share in the total electricity generation is low. Their load diagrams (Figure 1 for oil-fired plants) demonstrate that these plants only operate during the daytime in winter.

2.1.2. Specific direct emissions

Figure 2 shows the hourly emissions corresponding to the instantaneous working regimes of the power system. The top diagram shows the emissions of greenhouse gases. The other diagrams show the emissions of SO_x and NO_x. Dark parts show time segments of high specific emissions (emissions per kWh).

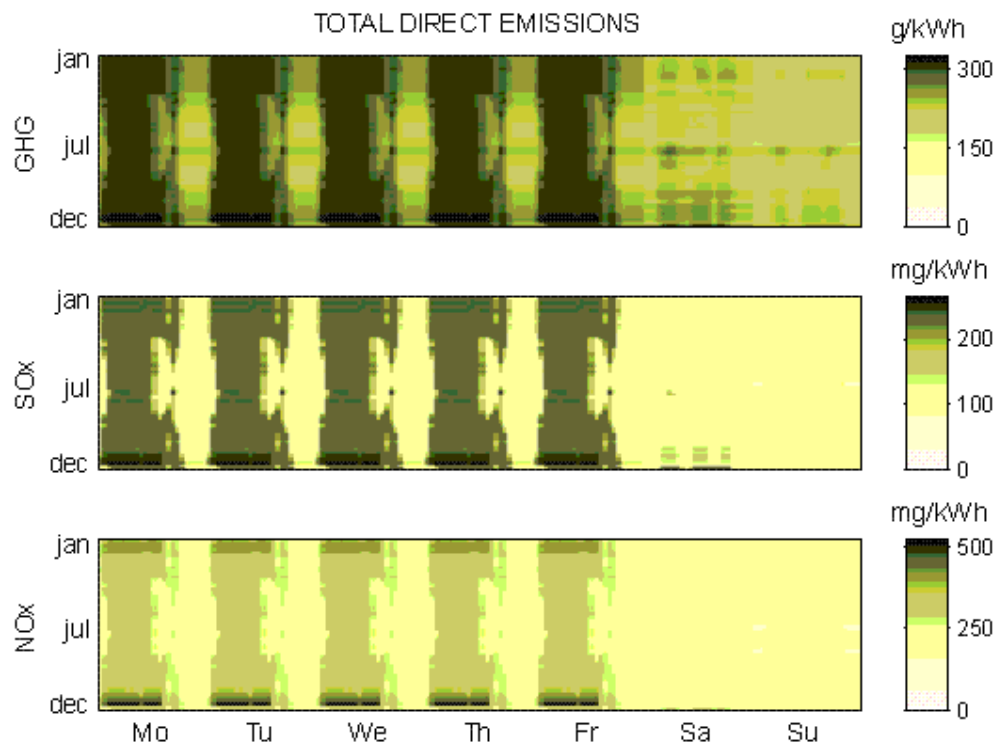


Figure 2 Specific emissions per hour; PROMIX-results for 2005

Since only direct emissions are taken into account, emissions are calculated according to the emission-responsibility of energy carriers. Therefore, specific emissions are not necessarily constant within a plant, but they can vary according to the working characteristic (energy use versus the activation level) of the plant. For fossil fuel power plants, low efficiency immediately translates into higher specific emissions (emissions per kWh). This is important because only actual base load power plants constantly operate at nominal (maximal) power, whereas the load of the other plants is varied to match the demand. Therefore, not the efficiency at full power, but the efficiency at the actual instantaneous working regime is considered in the model.

For nuclear power plants there are no direct emissions. All other true base load plants constantly operate at rated power, so their emissions are constant in time throughout the year. Cogeneration plants are simulated to operate at full power when activated. For the combined cycle (not constantly at nominal power, see Figure 1) and the coal-fired plants, the specific emissions increase with decreasing load. For the sum of all peak power plants, the specific emissions are relatively constant during activation. This is the result of the small scale of these plants. When activated, most of these plants operate at rated power.

Figure 2 clearly demonstrates the hour to hour emissions of GHG's, SO_x and NO_x. Comparison of this figure with the diagrams in Figure 1 shows that the peak values of all emissions are dominated by the coal-fired power plants. All three emission diagrams in Figure 2 look the same as the corresponding diagram of the electricity generation of coal-fired power plants in Figure 1. As the newest coal-fired power plants to be built are equipped with deNOX and deSOX equipment, (and as the older coal-fired power plants will mainly be decommissioned or updated), this link becomes less obvious. Already now, PROMIX-simulations show that the peak values of the SO_x and NO_x emissions of 2005 have dropped by more than a factor 2 compared to the peak values of 1997. But in any case the peak values of the GHG emissions are still dominated by the coal-fired power plants (with still low gas prices assumed).

To summarise, Figure 1 shows that the instantaneous electricity generation changes considerably with time. In the first place, changes in demand between day and night seem to affect the load carried by the coal-fired power plants (semi base load). Since coal-fired power plants dominate the overall emissions, modulation of these plants will also result in a change in overall instantaneous emissions. This is clearly demonstrated in the diagrams in Figure 2. This figure also proves that making calculations with a fixed value for the GHG's and other emissions (in literature the yearly average emissions are often used), may lead to false results; especially if the electric application is not active all the time, but only in a limited time segment (e.g., daytime versus night time applications). For Belgium, e.g., the average CO₂-emissions for 1997 were about 330 g/kWh whereas the instantaneous emissions vary between 100 and 400 g/kWh.

2.2. Impact of new investments and decommissioning

Both the expansion of the power system with new plants and the decommissioning of older plants evidently affect electricity generation and the corresponding emissions. The magnitude of the impact depends on the changes in the activation sequence of the power plants.

Figure 3 to Figure 6 show some examples of the impact of modifications made to the power system. These diagrams (schematic representations of the ranking order or "merit order") show how the electricity demand is met over an entire day. In reality, the activation order is more complex, but for the qualitative explanation of the impact, these simple approximative diagrams are quite appropriate. To obtain more accurate quantitative results, the modifications are also simulated in the detailed model PROMIX. The results of these simulations are shown in Table 1. Again, all examples are situated in the Belgian energetic context, and low gas prices are assumed.

2005 Belgium	reference	+ new combined cycle (Figure 3)	+ new coal-fired (Figure 4)	- old coal-fired (Figure 5)	- old coal-fired + new combined cycle (Figure 6)
ANNUAL GENERATION	90.0 TWh	90.0 TWh	90.0 TWh	90.0 TWh	90.0 TWh
base load ^(o)	60.3%	60.3%	60.3%	60.3%	60.3%
coal-fired	12.8%	11.9%	14.3%	11.7%	10.9%
gas-fired, CC	23.5%	25.3%	23.1%	23.7%	25.6%
rest: gas, oil, import	3.4%	2.5%	2.3%	4.3%	3.2%
ANNUAL GHG EMISSIONS	24.6 Mton	24.0 Mton	24.8 Mton	23.9 Mton	23.5 Mton

^(o) nuclear, cogeneration, blast furnace gas, renewables

Table 1 Impact of modifications to the power system

Figure 3 shows the schematic representation of the impact of the commissioning of a new combined cycle gas-fired plant. In the situation without this new plant (left figure of Figure 3), all combined cycle plants are already highly utilised. The coal-fired units have a higher (i.e., worse) activation order. The new combined cycle plant has a higher efficiency than the existing combined cycle plants. This means that this new combined cycle plant will have a lower overall ranking order. Figure 3 shows that the new combined cycle plant, so to speak, "pushes up" all other plants. Some coal-fired and peak power plants are "pushed out". The commissioning of a new combined cycle plant is also simulated with the model PROMIX. The results (which quantify the schematic representation of Figure 3) are shown in Table 1 (column: + *new combined cycle*). The increase in the production of the combined cycle plants (in comparison with the *reference* scenario) would result in a decrease in utilisation of the coal-fired plants (pushed out of base or semi base load) and the peak plants (almost pushed out entirely). The impact of this action is relatively large (GHG emission decrease of 0.6 Mton), because it causes a change in base load commitment.

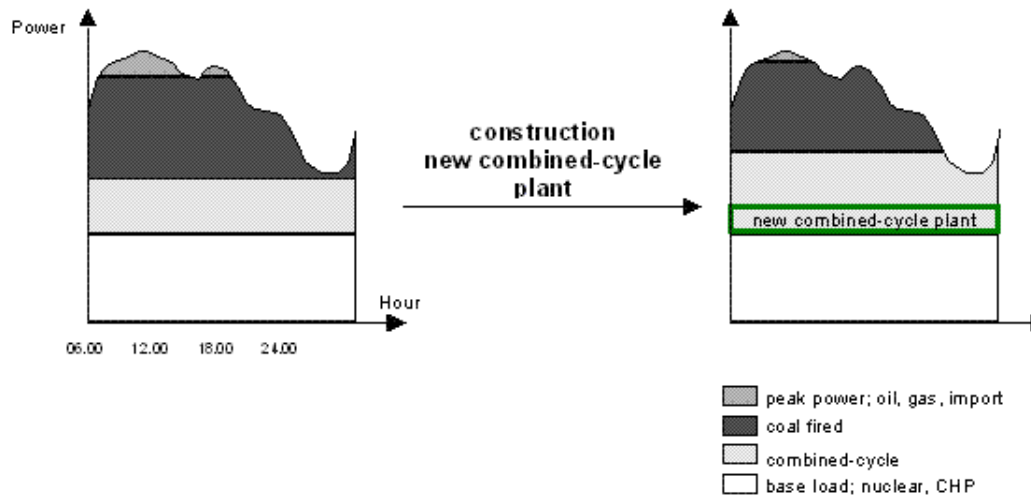


Figure 3 Impact of a new combined cycle power plant

It is often claimed that the commissioning of a new coal-fired power plant would be disastrous for the GHG emissions. With PROMIX, it is possible to verify whether this claim is true. Figure 4 schematically demonstrates what happens. The new coal-fired plant probably has a higher efficiency than the older ones. This means that this new plant will have the highest priority of all coal-fired plants, and that it would be activated right after the combined cycle plants. All other (more expensive) plants are "pushed up" in the activation order. This means that older coal-fired plants and some of the peak power plants are "pushed out" entirely. This scenario has also been simulated. The result of this simulation (shown in Table 1, column: + new coal-fired) demonstrates that the installation of a new coal-fired power plant mainly shifts part of the demand from peak plants to coal-fired plants. This action results in an increase in GHG emissions (increase of 0.2 Mton), but the increase is relatively low because of two reasons. Firstly, there is little or no impact on the base load level commitment. Only the production on semi base load and peak load level is affected. This means that the impact is only perceptible part of the time. Secondly, the difference in emissions between the new coal-fired plant and the plants "pushed out" is small (high efficiency coal-fired plant versus low efficiency coal-fired plants and gas and oil peak plants).

Figure 5 schematically shows the effect of the decommissioning of an old (less efficient) coal-fired power plant. Its role is completely taken over by the gas- and oil-fired plants. This can also be concluded from the simulation performed for this scenario of which the results are shown in Table 1 (column: - old coal-fired). The reduction in GHG emissions is again relatively large (decrease of 0.7 Mton) because of the poor efficiency of the decommissioned plant and the fact that it concerns a coal-fired plant, mainly replaced by oil and gas.

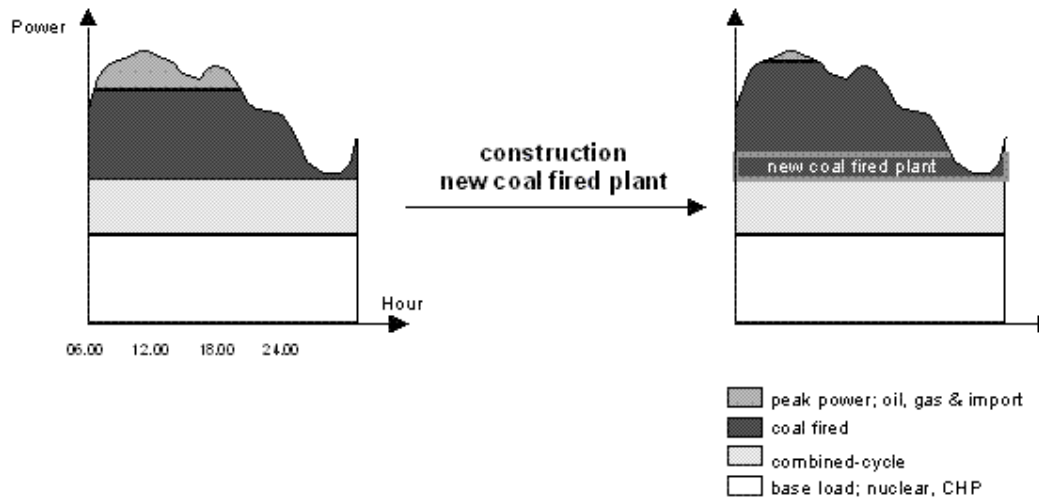


Figure 4 Impact of a new coal-fired power plant

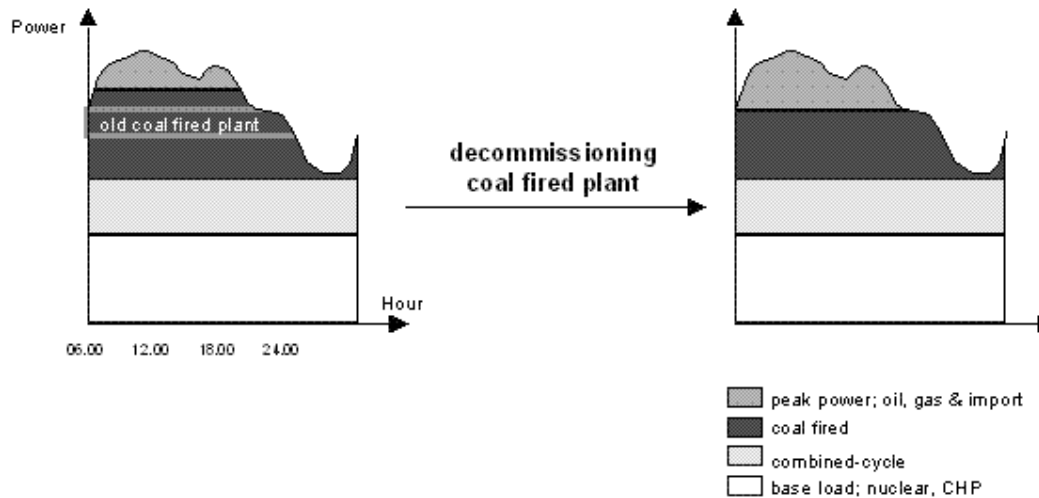


Figure 5 Impact of decommissioning an old coal-fired power plant

A combination of two above mentioned cases is discussed hereunder. An old and less efficient coal-fired plant is replaced with a new combined cycle plant. The impact of this action is schematically illustrated in Figure 6. The new combined cycle plant "pushes up" the rest of the plants. Part of the coal-fired power plants is "pushed out" of base or semi base load. Furthermore, the decommissioning of the old coal-fired plant guarantees that the peak is still covered by the older gas and oil plants, rather than by coal-fired plants. The combination of these effects results in a large reduction in GHG emissions (decrease of 1.1 Mton, see Table 1, column: old coal-fired + new combined cycle).

The difference between this combined action and the simple commissioning of a new combined cycle plant, is that the combined action causes a substitution between the coal-fired power plants and the combined cycle plants, whereas this substitution is only partial for the single action (see Table 1).

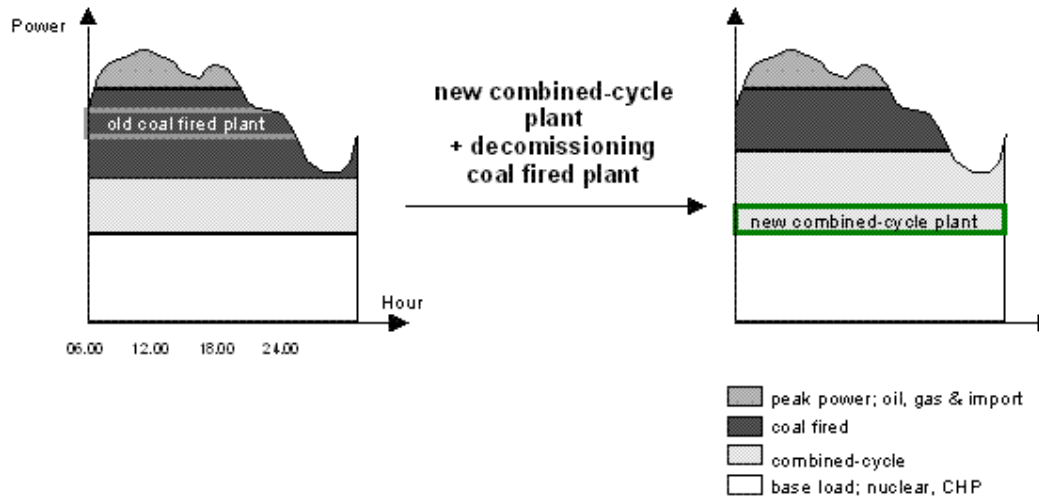


Figure 6 Impact of a new combined cycle power plant in replacement of an old coal-fired power plant

The examples worked out above illustrate that detailed system models such as PROMIX can be used for the qualitative and quantitative evaluation of the impact of specific supply side options. Simulation of four cases demonstrates that a simulation tool is essential in drawing quantitative conclusions. The model also comes in handy to verify qualitative a-priori statements, assumptions or prejudices.

3. CO₂-emissions due to embedded cogeneration; dynamic and integrated approach

In the evaluation of the value (energy saving and/or reduction in emissions) of potential installations for the combined generation of heat and electricity, usually simplified methods are used. Most of these methods compare the cogeneration unit to a hypothetical combination of an electric power plant and a heating furnace. The idea behind these methods is that a choice must be made between the installation of cogeneration and separate systems for electricity and heat. Although this comparison is theoretically plausible (if the cogeneration unit does not produce the heat and the power, other systems must do so), real world simulations show different results. It is therefore important to clearly delineate the application domains of these simplified comparison devices. In addition, in the ranges of operational parameters where these simplified methods do not apply, alternative and more correct approaches must be advocated.

3.1. Different methods for the evaluation of cogeneration

3.1.1. Static-Simplified comparison

The method that is being used most frequently is what we shall call the *static simplified comparison* of cogeneration and separate generation of heat and electricity. The key to the method is illustrated in Figure 7. On the left hand side, a cogeneration unit uses an amount of primary energy F_C and produces heat Q and electricity E . The efficiency of this conversion is denoted by α_E if defined for the electricity generation ($\alpha_E = E/F_C$) and α_Q if defined for heat production ($\alpha_Q = Q/F_C$). The loss can be written as $F_C - Q - E$, or $E/\alpha_E - Q - E$. On the right hand side, the same amounts of heat Q and electricity E are generated separately. The electric system considered has an efficiency of η_E and the furnace has an efficiency of η_Q . Therefore, the use of primary energy F_S in this case reads $E/\eta_E + Q/\eta_Q$. The loss can now be written as $F_S - E - Q$, or $E/\eta_E + Q/\eta_Q - E - Q$.

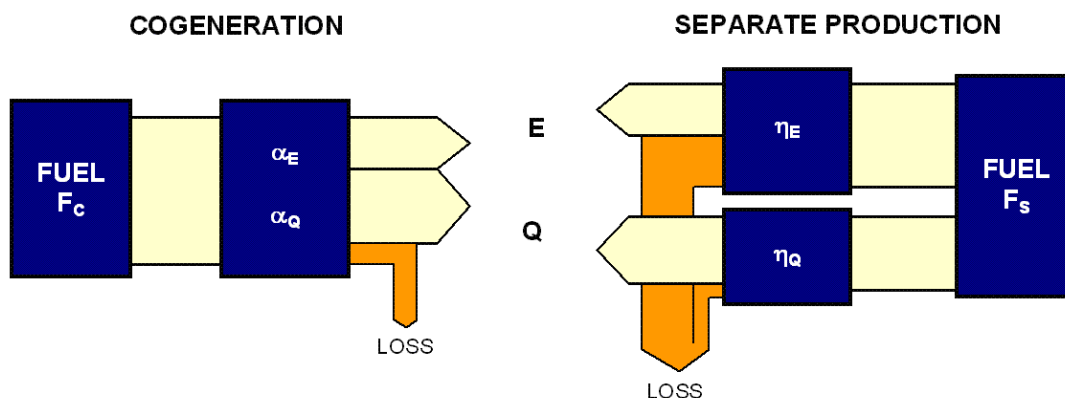


Figure 7 Simplified static comparison of cogeneration and separate generation of heat and power

Starting from the simple picture of Figure 7, several indicators or criteria can be used to express the value of the cogeneration unit. The most important are the absolute primary energy saving (aPES)

and the relative primary energy saving (rPES). The aPES combines two terms. The first one ($E/\eta_E + Q/\eta_Q$) represents the primary energy use in the case of separate generation of heat and electricity. The second term expresses the primary energy use of the cogeneration system. This can be expressed as a function of the heat generation (Q/α_Q) or as a function of the electricity generation (E/α_E).

$$\text{aPES} = \left(\frac{E}{\eta_E} + \frac{Q}{\eta_Q} \right) - \frac{E}{\alpha_E} = \left(\frac{E}{\eta_E} + \frac{Q}{\eta_Q} \right) - \frac{Q}{\alpha_Q}$$

The rPES shows the primary energy saving, relative to the power use in the separate generation units. Here, one has to keep in mind that $\alpha_E/\alpha_Q = E/Q$.

$$\text{rPES} = 1 - \frac{1}{\frac{\alpha_E}{\eta_E} + \frac{\alpha_Q}{\eta_Q}}$$

Both the representation in Figure 7 and the equations are very easy to understand and seem logical because in one case the heat and the power are delivered by cogeneration, while in the other, they are provided by separate generation units. Important in this comparison is that both options exclude one another. If the cogeneration unit is used, the separate generation units are non-existing and vice versa.

If one looks more closely, however, this comparison between cogeneration and separate production of heat and electricity is less obvious. Since no time duration aspects have been taken into account, the equivalence between both options must to be instantaneous. This means that both systems must deliver the same power (kW), but says nothing about energetic (kWh) aspects. If the instantaneous usage of both systems is not the same (and this is all but self-evident), there is no equivalence in power delivery. E.g., if a new combined cycle (CC) gas-fired unit is chosen for electricity generation, its annual use will be about 7000 h/a (under low gas price assumption). This is comparable to the annual use of (process) industrial cogeneration. The installation of cogeneration units clearly avoids the investment of the CC gas-fired unit and the static simplified comparison is acceptable. The annual use of the avoided CC gas-fired unit is, however, much larger than the annual use of cogeneration in the service & commercial or the domestic sectors (about 4000 h/a or less). An evident question therefore is what happens during the time where the cogeneration unit(s) is (are) not active, if the installation of these cogeneration units has likewise prevented the investment in a new CC plant. Clearly, the CC power plant cannot be used because it has not been built... Therefore, this generation gap has to be filled by other means. These means are not taken into account in this static simplified method.

Likewise, the possibility that one of the systems (cogeneration, power plant or furnace) operates at partial load with an efficiency lower than the rated efficiency cannot be evaluated with this static simplified method because only nominal efficiencies are used. Also, the need for back-up furnaces in the case where the cogeneration unit itself cannot deliver all the heat required, is not accounted for.

3.1.2. Static comparison including overall operation time

To meet the objection that no time aspects are taken into account in the static simplified comparison, attempts have been made to statically include time aspects by looking at the annual use of the technologies considered. This method is illustrated in Figure 8. Again, the situations with cogeneration and with the separate production of electricity and heat are compared. Now also the annual operational duration is taken into account. In the case where cogeneration is installed, it produces heat and power. Call U_{cogen} the annual operational duration of this unit. The rest of the time (in total $8760 - U_{\text{cogen}}$ hours), other production units will have to take over electricity generation ('back-up' power plant in Figure 8). In the case of separate production, furnaces deliver the heat and an electric power plant delivers electricity. The total operational duration of this plant is called U_{plant} . For the rest of the time (in total $8760 - U_{\text{plant}}$ hours), other production units have to take over.

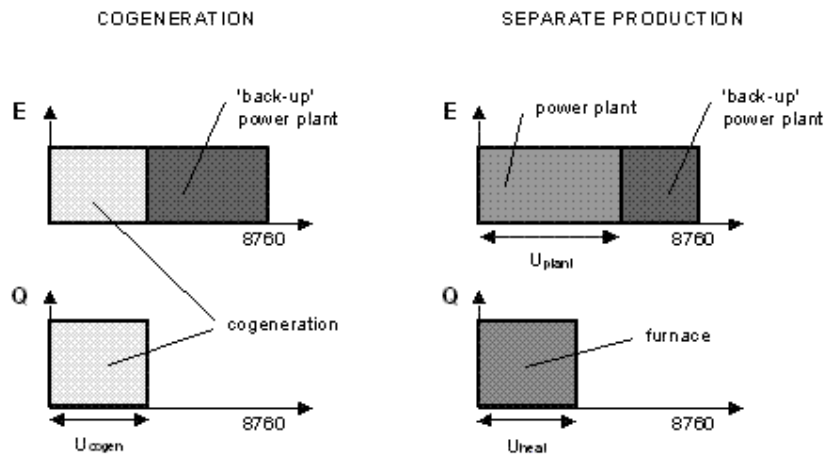


Figure 8 Static comparison of cogeneration and separate generation of heat and power, including overall operation time

Using the representation in Figure 8, the following condition for primary energy saving through cogeneration means can be derived:

$$\frac{E \cdot U_{\text{plant}}}{\eta_{\text{plant}}} + \frac{E \cdot (8760 - U_{\text{plant}})}{\eta_{\text{back-up}}} + \frac{Q \cdot U_{\text{heat}}}{\eta_{\text{furnace}}} > \frac{E \cdot U_{\text{cogen}}}{\alpha_E} + \frac{E \cdot (8760 - U_{\text{cogen}})}{\eta_{\text{back-up}}}$$

In this formula, the expression on the left hand side represents the primary energy use for separate generation. The terms stand for the primary energy use of the power plant, of the back-up power plant and of the furnace, respectively. The expression on the right hand side stands for the primary energy use in the case of cogeneration. Here, the terms stand for the primary energy use of the cogeneration unit and of the back-up power plant, respectively. E and Q represent the electric and thermal power of the systems.

Although, at first sight, this approach seems to deal with the main shortcoming of the static simplified method discussed in section 3.1.1, it does not really. Both in the equation and in Figure 8, a choice has to be made for the so-called 'back-up' power plant system used at times where the cogeneration unit or the power plant are inactive. In reality, there is no power plant that is 'reserved' for this purpose; the additional power will be delivered by the plants still available in the power system. If possible, already activated plants can be modulated to deliver this power. If all plants already operate at maximum power level, new plants will have to be started. In addition, the dynamic response of the central power system is completely neglected by this modified static comparison of Figure 8. Only the integrated operational duration of all systems is considered. It is important to recognise that the reaction of the central power system depends on the instantaneous power demand, not the annual electric energy demand. If the hours during which additional power is required are consecutive, a large power station may be used to cover this demand. If not, the fluctuations will probably be levelled with peak power plants or possibly even with pumping units. The only possibility to get some kind of results from this advanced static method would be to fill in all possibilities for the additional power needs, from the modulation of the most efficient plant to the start-up of the least efficient one, by some kind of parameter study. This will, however, not lead to concrete results but a large range of results. Interpretation of these results is effectively impossible.

Finally, this modified method still does not take into account the possibility of systems working at partial load and the need for back-up heating in the case of cogeneration.

3.1.3. Dynamic approach

Even if one uses more sophisticated static methods, by definition, it is impossible to include dynamic considerations in a static formulation. To properly take into account the dynamic considerations, the entire instantaneous power (electricity and heating) context has to be simulated. As mentioned above, for Belgium, the model PROMIX dynamically simulates the hourly electricity generation. For heating, the hourly heat demand of the application or the sector can be used.

3.2. Application examples

In order to demonstrate the importance of the dynamic simulation of cogeneration in the entire instantaneous power context, three applications are briefly considered. In the first case, industrial cogeneration is simulated; in the second, cogeneration in the commercial sector is looked at and in the third one, the consequences of the massive implementation of cogeneration for residential heating is examined.

Figure 9 illustrates the method to evaluate the impact of cogeneration. Two situations are compared; a first without and a second with the installation of additionally postulated cogeneration. In this second situation, care has to be taken that the entire instantaneous power context is evaluated. If the additional cogeneration prevents the installation of new central power units, this also has to be accounted for in the simulation. The boundary condition linking both situations is that the final power delivery (electricity and heat) has to be the same. Therefore, the differences (in primary energy use and in emissions) between both situations can be fully ascribed to the assumed additional cogeneration.

The period between 2000 and 2010 has been considered and simulations have been done with the PROMIX-simulation tool.

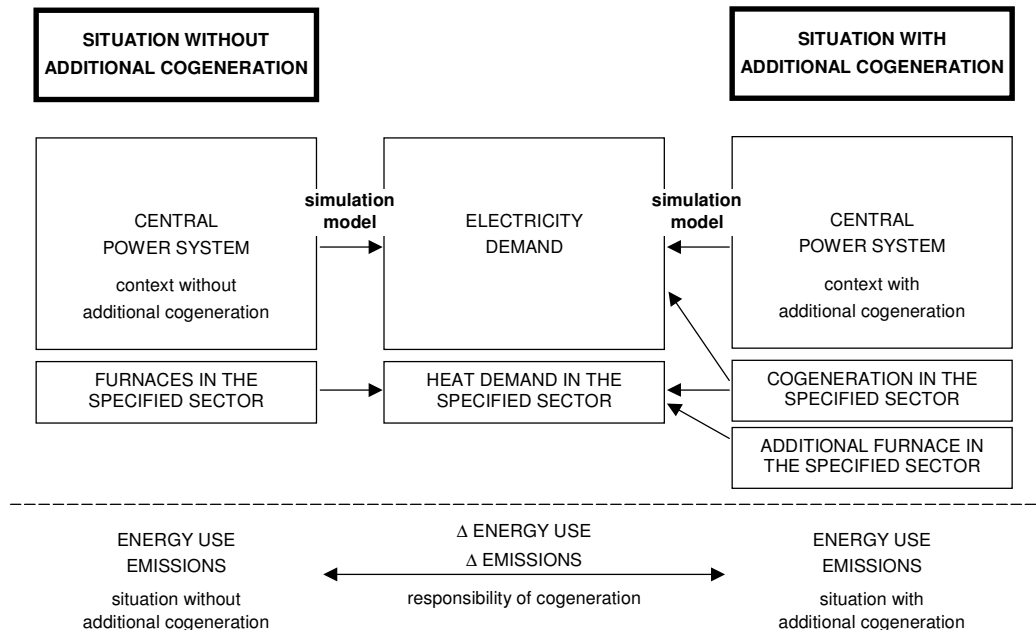


Figure 9 Method for the evaluation of cogeneration

Normally, as those examples are system approaches, they should be taken into account in Work Package 5. But as the models², used for the scenario analyses on a European scale, are not accurate enough for such detailed simulations, they are treated in this Work Package, to some extent as a characteristic of the cogeneration technology (albeit dependent on the overall generation system).

3.2.1. Industrial cogeneration

By 2010 about 1700 MW_{el} industrial cogeneration will already be present in the reference scenario of our simulations. In this case study on industrial cogeneration, an additional 360 MW_{el} (or 400 MW_{el} with a reliability of 90%) of gas-fired (GT-based) CHP is added.

The industrial demand for process heat is more or less constant throughout the year (approx. 360 MW_{th} in this simulation). In some cases, heat demand only appears during business hours (only weekdays), but most big industries operate continuously. As no large short term fluctuation appears and only some units shut down during nights and/or weekends, the cogeneration units can be dimensioned to deliver the entire heat demand. The electricity generation of these units has the same shape as the heat demand, with a maximum of 360 MW_{el} ($\alpha_E = 38\%$, $\alpha_Q = 42\%$). The average annual use of these cogeneration units is about 7500 h/a.

² In the EUSUSTEL-project, Work Package 5 mainly focuses on the simulation codes PRIMES and TIMES-EE.

Using the method described above, two situations are simulated. In the first, no additional industrial cogeneration is simulated. In the second, 360 MW_{el} of industrial cogeneration is added. Because this cogeneration lowers the demand peak for the central power system, also the investment strategy in central power stations will be altered. In the current energetic context of assumed low gas prices this means that one CC gas-fired unit of 400 MW_{el} (and a reliability of 90%) would not be built.

Comparison of both scenarios shows that the installation of 360 MW_{el} of industrial cogeneration would be responsible for an overall reduction in primary energy use and in greenhouse-gas emissions of 4000 TJ and 250 kton, respectively.

These results are comparable to the results of the static simplified comparison (described in section 3.1.1); namely 4000 TJ and 240 kton. In this specific case of industrial cogeneration, the simplified comparison seems to be valid. Indeed, none of the objections stated in section 3.1.1 applies here. The annual use of the cogeneration units approaches the annual use of the CC gas-fired unit and all systems continuously operate at full load.

3.2.2. Cogeneration in the commercial sector

In the second case study, 360 MW_{el} of additional cogeneration in the commercial sector is installed. Since most of the heat demand in the commercial sector is used for space heating of buildings, its annual use is low. Also, because the heat demand strongly fluctuates, the cogeneration units will be dimensioned to cover a more constant base load. The peaks and the fluctuation are still covered by furnaces. In Figure 10, the heat demand in this sector is plotted together with the heat production from the cogeneration units (Figure 10 is a typical realistic heat demand and supply profile). The annual use of this cogeneration happens to be limited to about 4000 h/a. The electric and thermal conversion factors α_E and α_Q are 35% en 50%, respectively. Because the heat demand for space heating happens in winter time, when for Belgian climatic circumstances electricity demand peaks, this type of cogeneration will also interact with the investment strategy of the central power system, leading to the avoidance of the construction of one CC gas-fired unit of 400 MW_{el}.

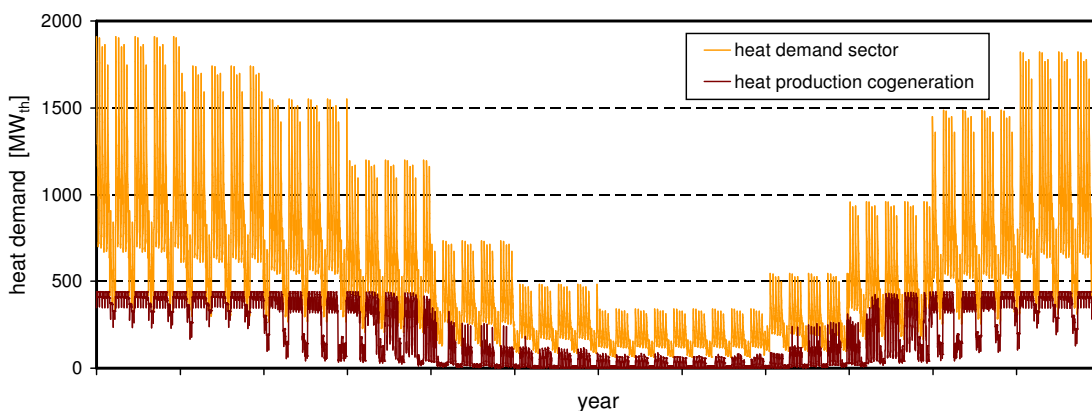


Figure 10 Heat demand in the commercial sector and heat generation from cogeneration

The results of the simulations with and without an additional 360 MW_{el} (mainly gas-fired CHP engines) in the service & commercial sector by 2010 show that here the extra cogeneration could claim an overall reduction in primary energy use and greenhouse-gas emissions of 1800 TJ and 30 kton, respectively. The results for the simplified static comparison are much more favourable, namely a reduction in energy use and greenhouse-gas emissions of 2900 TJ and 170 kton, respectively. It is clear that the static simplified comparison largely overestimates the potential of this type of cogeneration. Looking at the objections to this method (see section 3.1.1) we see that the main shortcoming here is that the annual use of these cogeneration units is much smaller than that of the avoided CC gas-fired plant, namely 4000 h/a versus 7000 h/a. Therefore, both systems are not equivalent with respect to instantaneous power generation and part of the central power system will have to make up for the difference. Looking more closely at the detailed results of the simulations (as recalled, based on assumed low gas prices), we find that this additional power mainly comes from coal-fired power plants. In the case with additional cogeneration, the electricity generation of the CC gas-fired units decreases from 32 110 GWh to 30 450 GWh (which is logical because one less CC gas-fired unit has been built) whereas the generation of the coal-fired units rises from 2 600 GWh to 2 830 GWh. Since these coal-fired plants are less efficient and emit much more greenhouse-gases, the result from the dynamic simulation is much less favourable than predicted by the static method.

It is also important that this additional power generation is strongly time dependent because it has to be delivered by the remaining available power plants. The extra power can be delivered by modulation of plants not yet working at full load or by new plants. It also depends on the duration of the power fluctuations. For short disturbances, peak power units or pumping plants may be used. For longer periods, also larger plants may have to be started. A static model can by definition not take into account these dynamic time dependent considerations. Since the model PROMIX simulates electricity generation on an hourly basis, it can take into account the dynamic context appropriately.

3.2.3. Massive implementation of cogeneration for residential heating

For the evaluation of the implementation of cogeneration for residential heating, several scenarios are calculated. A first parameter that is varied is the time period in which the (gas) engine is allowed to operate. Three cases are discussed. One case, where the cogeneration unit is coupled directly to the heat demand, is comparable to the thermostatic operation of a classic boiler for domestic heating. In the second case, the cogeneration unit is only allowed to operate during the daytime, during which also storage of heat is possible. In the third case, the unit may only operate at night, again with the possibility to store excess heat.

The second parameter is the thermal size of the individual cogeneration units. Here, two cases are discussed. In the first case, the unit is able to deliver thermal peak demand, including the losses due to heat transportation. In the second case, the thermal power of the engine can only cover 43% of the peak. In all cases, back-up furnaces are installed, able to deliver all the heat.

In all scenarios, the heat demand has a qualitative demand profile as presented in Figure 10³. This profile includes room heating and hot water production. As the order of magnitude depends on the number of households considered, one must not look at the values of the ordinate. In all cases, 360 MW_{el} of additional cogeneration is installed. As in the examples above, all alternative scenarios are compared to a reference scenario for 2010.

In the evaluation of the impact of the implementation of cogeneration in an overall energetic context, the results of the simulations show that there are two parameters that seem to affect the qualification of cogeneration.

The first parameter is the interaction between the cogeneration units and the expansion of the central power system. If the cogeneration units are activated during the daytime, the expansion of the central power system is slowed down. This means that the commissioning of a new CC gas-fired unit would be prevented. Because of the limited annual use of the cogeneration units installed for residential heating, these units cannot fully replace a new power plant which would have operated in base load. Therefore, the load of other units (partly less efficient coal-fired units) must increase, which is unfavourable for both the primary energy savings and the GHG emission reduction.

On the other hand, if the additional cogeneration cannot prevent the commissioning of this new plant (when the cogeneration units operate off peak), the results become much more favourable. Indeed, now the cogeneration units take over part of the electricity generation formerly produced by central power stations (partly coal-fired units with much higher emissions). Although, economically, it seems illogical to invest in both the cogeneration units and the CC gas-fired plant, this is beneficial for energy saving and emission reduction.

The second parameter that affects the results is the annual operation time of the cogeneration units. If the annual use becomes larger, also the potential primary energy savings and emission reductions increase because central power generation, partly coal-fired, diminishes. This increase in operation time can be accomplished by reducing the size of the individual cogeneration units, allowing them to mainly carry thermal base load.

The simulations have been carried out for both the assumed low gas price scenarios and a variation of those prices (i.e. gas prices higher with a factor 3, while coal prices only higher with a factor 1.5). Both price scenario simulations give comparable qualitative results. The abovementioned results give the same tendencies if one assumes a CO₂-tax. By this tax, the gas price becomes artificially lower, compared to the coal price.

³ Figure 10 presents the heat profile of the commercial sector. But as the shape of the curve for the residential sector is the same, and as the absolute values are not of importance here, the same curve can be used, to give a qualitative idea of the demand curve.

4. Conclusions

In order to make a fool-proof evaluation where all aspects of electricity generation are kept in mind, a detailed simulation tool for electricity generation is useful tool. Here, in this discussion, the simulation code, called PROMIX, was used. Although, its simulations only deal with the Belgian context and a certain fuel price structure, its results can easily be interpreted on a larger European framework and other price settings.

Case studies clearly demonstrate that some impacts can be estimated without calculation, but that precise quantification of an impact always has to be the result of a simulation. When a scenario becomes complicated (for instance simultaneous demand and supply side actions), a-priori statements are difficult or even impossible to be made. Therefore, simulation of electricity generation for all relevant scenarios is essential in order to study the impact of demand or supply-side options, or both at the same time.

When electric demand fluctuates, the instantaneous fuel mix for electricity generation changes. Reduction (increase) in demand does not result in the same relative reduction (increase) for all active power plants. Instantaneously, only the most expensive plants are shut down (activated) or modulated. The properties of the *average* system are not relevant because incremental changes in demand only affect the activation of this limited number of plants, characterized by their own emissions, efficiency and fuel costs.

If demand changes cause changes in the evolution of the power system, larger variations in GHG emissions can be obtained. This is specially the case, when the action on the demand side triggers a technology with a high load factor (base load or semi base load; e.g. some sort of electric heating). If a new base load plant is built in order to respond to an additional demand peak, the plant will not only be activated during the period of the additional demand, but (almost) continuously. This plant will therefore has a considerable impact on the GHG emissions.

5. References

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