Appendix – The EU-25 Power Sector: a System Dynamics Model of Competing Electricity Generation Technologies

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August 22, 2007

1 Feedback Loops – Feedback Loop Diagrams

The feedback loop diagram in figure 1 is broken down in feedback loops concerning wind power (1a, 2, 3, 4a, 5a, 6a, 7a, 8a, 9a, 10a, 11a1, 11a2, 12a, 14a) and feedback loops concerning the other generation technologies considered [technology i] (1b, 4b, 5b, 6b, 7b, 8b, 10b, 11b, 12b, 13 and 14b). See figure 2 for a clearer picture of feedback loops 1a, 2, 3, 4a, 5a, 6a, 7a, 10a, 11a1 and 11a2. See figure 1 for feedback loops 8a, 8b, 9, 12a, 12b, 13, 14 and 15. The other electricity generation technologies (technology i) considered are gas-based, coal-based, nuclear-based, (potential) clean coal-based, biomass-based, solar PV, hydro and geotherm electricity generation technologies. When the corresponding feedback loops are similar –such as feedback loops 1a and 1b– then only one feedback loop will be discussed, mostly the one concerning wind power. This break-up makes the feedback loop diagram more complicated than strictly necessary, but also allows us to focus on wind power. The following feedback effects are –generally speaking– dealt with:

Feedback loops 1a and 1b – the positive *experience-cost* loops (+) **:** Investments in wind power capacity increase the cumulative historic wind power capacity sold which increases learning and experience of the wind power sector which decreases the marginal investment cost of new wind power capacity installed in the future which increases the relative attractiveness of new investments in new wind power capacity, which leads in turn to even more investments in wind power capacity, and so on, or in terms of feedback loop 1a: *investment wind power capacity* $\xrightarrow[+]{}$ *cumulative historic wind power capacity sold* $\xrightarrow[+]{}$ *learning and experience wind power* $\xrightarrow[-]{}$ *marginal investment cost new wind power capacity* $\xrightarrow[-]{}$ *exp margin new wind capacity* $\xrightarrow[+]{}$ *relative attractiveness investment in new wind power capacity* and again $\xrightarrow[-]{}$ *investment wind power capacity.* The investment costs of the other technologies considered also decrease with experience gained, following their specific learning curves (see feedback loop 1b).

Feedback loop 2 – the positive *wind power potential expansion* loop (+) **:** The decreasing marginal investment costs of new wind power capacity installed increase the maximum wind power potentiality, increasing the gap with the wind power capacity installed (see feedback loop 3), decreasing the siting costs (more sites available given the lower investment costs) and other investment costs, increasing the relative attractiveness of investing in new wind power capacity, which –ceteris paribus– leads to more investments in wind power capacity, to more cumulative historic wind power capacity sold which increases the learning and experience of the European wind

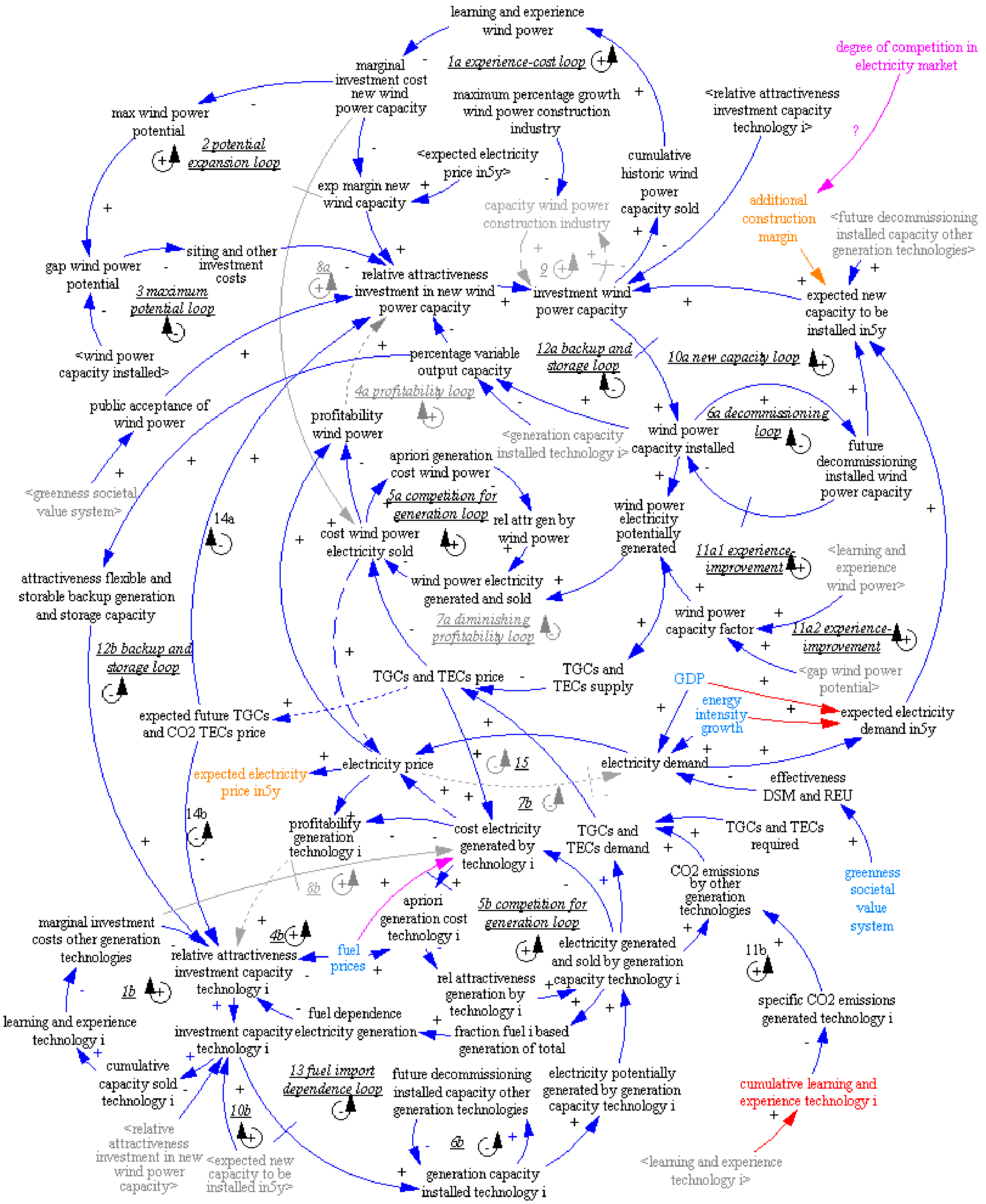

Figure 1: General feedback loop diagram of the EU-25 wind power model

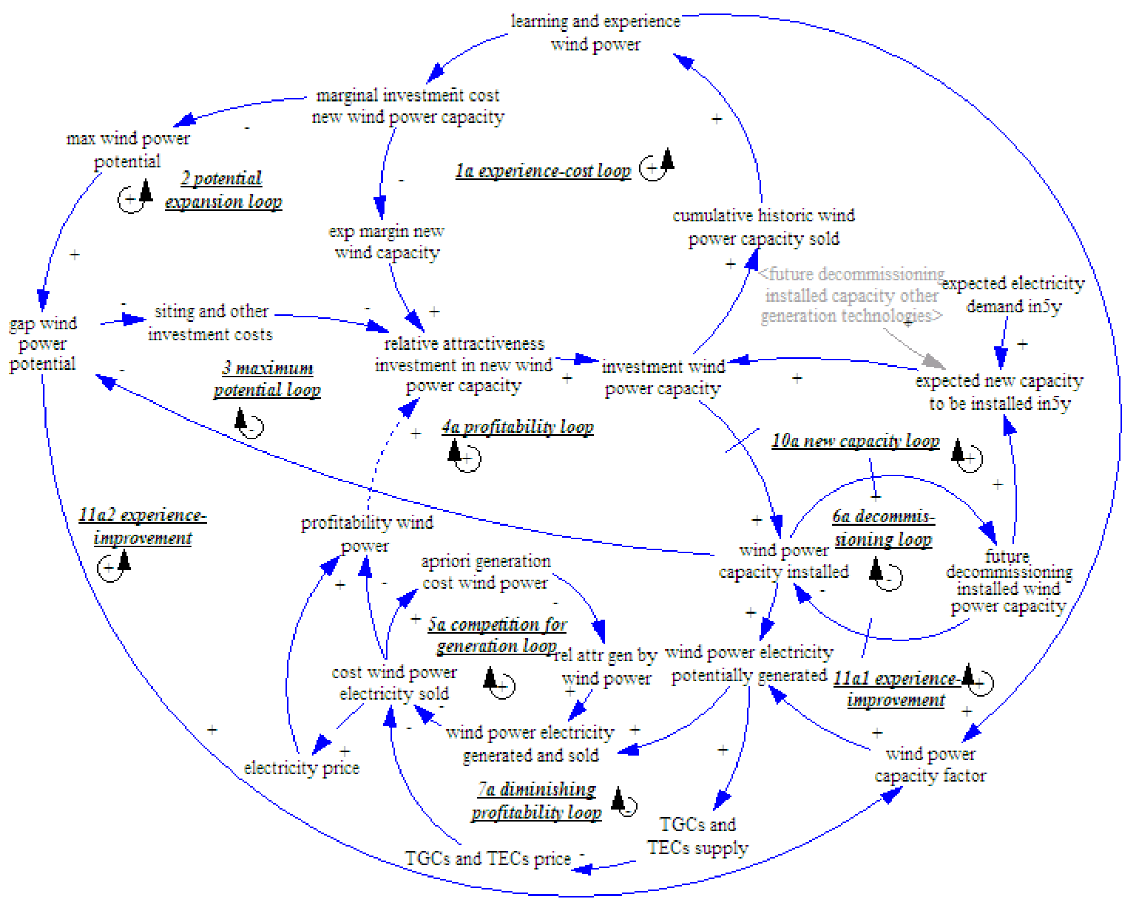

Figure 2: Feedback loops 1a, 2, 3, 4a, 5a, 6a, 7a, 10a, 11a1 and 11a2

power sector which decreases even more the marginal investment cost of new wind power capacity installed, and so on, or in terms of feedback loop 2: *marginal investment cost new wind power capacity*$\xrightarrow[-]{}$*max wind power potential*$\xrightarrow[+]{}$*gap wind power potential*$\xrightarrow[-]{}$*siting and other investment costs* $\xrightarrow[-]{}$*relative attractiveness investment in new wind power capacity*$\xrightarrow[+]{}$*investment wind power capacity* $\xrightarrow[+]{}$ *cumulative historic wind power capacity sold*$\xrightarrow[+]{}$ *learning and experience wind power*$\xrightarrow[-]{}$*marginal investment cost new wind power capacity.*

Feedback loop 3 – the negative *maximum potential* loop $\circleddash$ **:** The more wind power capacity installed, the smaller –ceteris paribus– the gap to the maximum wind power potential becomes, which makes investing in new wind power less interesting, especially because of increasing siting and other costs, which slows new investments in wind power capacity and hence –with a delay– also the increase in wind power capacity installed, and so on, or in terms of feedback loop 3: *wind power capacity installed*[1]$\xrightarrow[-]{}$*gap wind power potential*$\xrightarrow[-]{}$*siting and other investment costs*$\xrightarrow[-]{}$ *relative attractiveness investment in new wind power capacity*$\xrightarrow[+]{}$ *investment wind power capacity* $\xrightarrow[+]{/\!/}$ *wind power capacity installed.*

Feedback loops 4a and 4b – the positive *profitability* loops $\oplus$ **:** The name of these positive feedback loops and one of their causal links is displayed in grey in the feedback loop diagram for two reasons: (i) because it contains a clear simplification of reality, and (ii) because of its relatively modest influence on the model. There is namely no real financing and investment module in the model which would allow the use of own capital and available cash –both generated by past profits– for additional capital investments. Therefore the assumption is made that current profitability slightly influences the relative attractiveness of capacity investments, which drives the investments in capacity and after a delay also the capacity installed, which in turn increases the electricity generated by the technology. Now, the more electricity potentially generated by the installed capacity, the more electricity that could be sold, the lower the cost of the electricity generated or sold, which increases –given the electricity price– the profitability of the technology, and so on, or in terms of the wind power feedback loop (4a): *profitability wind power*$\xrightarrow[+]{}$*relative attractiveness investment in new wind power capacity*$\xrightarrow[+]{}$*investment wind power capacity*$\xrightarrow[+]{/\!/}$*wind power capacity installed*$\xrightarrow[+]{}$*wind power electricity potentially generated*$\xrightarrow[+]{}$*wind power electricity generated and sold*$\xrightarrow[-]{}$*cost wind power electricity sold*$\xrightarrow[-]{}$*profitability wind power.* Feedback loop 4b represents the same profitability-investment mechanism applied to the other technologies.

Feedback loops 5a and 5b – the positive *competition for generation* loops $\oplus$ **:** Feedback loops 5a and 5b together represent the competition between the technologies installed to be used for generation purposes, or in terms of wind power generation (feedback loop 5a): *wind power electricity generated and sold*$\xrightarrow[-]{}$*cost wind power electricity sold*$\xrightarrow[+]{}$[2] *apriori generation cost wind power* $\xrightarrow[-]{}$ *relative attractiveness generation by wind power*$\xrightarrow[+]{}$*wind power electricity generated and sold.* Moreover, the *apriori generation cost* of *technology i* in feedback loop 5b increases –in case of generation dependent on (fossil, nuclear,. . .) fuels– if the (exogenous) fuel price of the fuel required increases. The fuel prices are not modelled endogenously, because the endogenous fuel demand is only a small fraction of the total demand on the world markets. Nevertheless, fuel prices and even more the expected fuel prices will most probably seriously influence the wind energy dynamics. This is why several fuel price scenarios are considered and the sensitivity to different fuel prices are explored later on.

Feedback loops 6a and 6b – the negative *decommissioning* loops $\circleddash$ **:** These negative feedback loops decrease with some delay the capacity installed through decommissioning of the

[1]Note that this –'shadow'– variable is displayed as <wind power capacity installed> in the feedback loop diagram because it already appears elsewhere in the model.

[2]This causal link is computed slightly differently in the simulation model. There, the a priori costs are calculated by means of the new information about the capital invested, but with for example the information about the TGC prices of the previous year.

capacity installed at the end of its lifetime, or in terms of feedback loop 6a: *wind power capacity installed* $\xrightarrow[+]{}$ *future decommissioning installed wind power capacity* $\xrightarrow[-]{}$ *wind power capacity installed.* Different decommissioning model structures –such as decommissioning after exactly the lifetime, or the annual decommissioning of the capacity installed by 1 over the lifetime– are possible and influence the behaviour of the model. This feedback loop, together with positive feedback loops 10a and 10b leads to replacement investments, proportional to the relative attractiveness of capacity investments of the respective technologies, not necessarily the same technology as the decommissioned one.

Feedback loops 7a and 7b – the negative *diminishing profitability* loops $\ominus$ **:** Feedback loop 4a is weakened in case of a (too) successful development of wind power capacity installed because of the decreasing market price of the CO_2 tradable emission certificates (TECs) and tradable green certificates (TGCs) with increasing TGCs and TECs supply given their respective quantities required and their resulting demands, or in terms of feedback loop 7a: *wind power electricity potentially generated*[3] $\xrightarrow[+]{}$ *TGCs and TECs supply* $\xrightarrow[-]{}$ *TGCs and TECs price* (given the *TGCs and TECs demand*) $\xrightarrow[-]{}$ *cost wind power electricity sold.*

The *diminishing profitability* loops of other non-renewable technologies (feedback loop 7b) are characterised by a slightly different mechanism. Their generation costs increase with the cost of acquiring TGCs[4] and/or CO_2 TECs[5].

Feedback loops 8a and 8b – the positive *generation cost reduction* loops $\oplus$ **:** Decreasing marginal investment cost of new capacity installed will gradually/slowly decrease the cost of electricity sold, and will –given the electricity price– result in a higher profitability of that technology, and so on, or in terms of feedback loop 8a: *marginal investment cost new wind power capacity* $\xrightarrow[+]{}$ *cost wind power electricity sold* $\xrightarrow[-]{}$ *profitability wind power* $\xrightarrow[+]{}$ *relative attractiveness investment in new wind power capacity* $\xrightarrow[+]{}$ *investment wind power capacity* $\xrightarrow[+]{}$ *cumulative historic wind power capacity sold* $\xrightarrow[+]{}$ *learning and experience wind power* $\xrightarrow[-]{}$ *marginal investment cost new wind power capacity.* Feedback loop 8b –dealing with the other generation technologies– is characterised by the same structure.

Feedback loop 9 – the positive *capacity expansion of the wind power construction industry* loop $\oplus$ **:** The capacity expansion of the wind power construction industry loop is –at first sight– a positive feedback loop structure which combines push and pull effects of the wind power construction industry: the more investments in wind power capacity (pull), the bigger the capacity of the wind power construction industry will become, and the bigger the wind power construction industry, the more push leading to more investments in wind power capacity. This is for example the case in the models discussed in (Pruyt 2004): there the capacity of the wind power construction industry drives the commissioning of new wind power capacity. However, in the current model, the variable *maximum growth wind power construction industry* only tops the growth of the wind power construction industry *if* the investments in wind energy rise by more than a certain percentage –this limited capacity expansion is also seen in the real-world[6]. This negative influence tops and thus slows both capacity expansions and should therefore be seen as a negative feedback loop only if the rate of expansion increases above the maximum growth rate of the wind power construction industry. In terms of the variables displayed in the feedback loop

[3] *Wind power electricity potentially generated* drives the *TGCs and TECs supply* in the feedback loop diagram because the electricity generated might not be sold, but still generates TGCs. This is not the case for TECs. In the stock-flow diagram, the detailed structures are elaborated (more) correctly.

[4] *Electricity generated and sold by generation capacity technology i* $\xrightarrow[+]{}$ *TGCs and TECs demand* $\xrightarrow[+]{}$ *TGCs and TECs price* $\xrightarrow[+]{}$ *cost electricity generated by technology i*, and so on.

[5] *Electricity generated and sold by generation capacity technology i* $\xrightarrow[+]{}$ *CO_2 emissions by other generation technologies* $\xrightarrow[+]{}$ *TGCs and TECs demand* $\xrightarrow[+]{}$ *TGCs and TECs price* $\xrightarrow[+]{}$ *cost electricity generated by technology i*, and so on.

[6] Currently, production capacity is indeed a limiting or slowing factor for several wind turbine producers and wind power plant developers such as for example Gamesa –worldwide the second biggest player with a market share of more than 18%– whose demand exceeds their production capacity –even after expansion.

diagram, this gives: *investment wind power capacity* $\underset{+}{\nrightarrow}$ *capacity wind power construction industry* –which is possibly topped by *maximum growth wind power construction industry*– $\xrightarrow[+]{}$ *investment wind power capacity.*

Equivalent loops are considered for other modules dealing with niche market technologies with enormous growth rates (such as solar photovoltaic (PV) power), not for conventional technologies. The assumption behind the unlimited growth rates of the capacity of the conventional energy technologies is that these industries are mature. It might however be possible to vary slightly the construction delay of these mature construction industries with the respective new capacities commissioned. This is not explored here.

Feedback loop 10a and 10b – the positive *new capacity required* loops $\oplus$ **:** These positive feedback loops reflect the fact that the more installed capacity is decommissioned –ceteris paribus– the more capacity replacements are required to satisfy the electricity demand, or in terms of feedback loop 10a: *investment wind power capacity* $\underset{+}{\nrightarrow}$ *wind power capacity installed* $\xrightarrow[+]{}$ *future decommissioning installed wind power capacity* $\xrightarrow[+]{}$ *expected new capacity to be installed in 5y* $\xrightarrow[+]{}$ *investment wind power capacity.* The forecasting time horizon is taken to be 5 years here –which is of course a simplification. The *expected new capacity to be installed in 5y* is also fuelled by the *future decommissioning installed capacity other generation technologies*, and by the *expected new capacity to be installed in5y.*

And the proportion of this *expected new capacity to be installed in 5y* assigned to a particular technology depends on the relative attractiveness of investing in the particular technology (*relative attractiveness investment in new wind power capacity* and *relative attractiveness investment capacity technology i*).

Feedback loops 11a1 and 11a2, and 11b – the positive *experience improvement* loops $\oplus$ and $\oplus$ **:** Feedback loops 11a1 and 11a2, and 11b are related to feedback loops 1a and 1b respectively –which deal with the decreasing investment costs with increasing experience– because they embody different aspects related to increasing experience and learning. Feedback loop 11a1 deals with the increasing capacity factor with increasing learning and experience: *learning and experience wind power* $\xrightarrow[+]{}$ *wind power capacity factor* $\xrightarrow[+]{}$ *wind power electricity potentially generated*, and so on (see loops 1a and 2). Related to this feedback loop is feedback loop 11a2 concerning the dynamic gap of wind power potential: *gap wind power potential* $\underset{+}{\nrightarrow}$ *wind power capacity factor* $\xrightarrow[+]{}$ *wind power electricity potentially generated*, and so on (see also loops 1a and 2).

And feedback loop 11b is related to loop 1b and reduces the marginal CO_2 emissions[7] with increasing learning and experience of the respective CO_2 emitting technologies.

Feedback loops 12a and 12b – the negative *backup and storage* loops $\ominus$ and $\ominus$ **:** The negative *backup and storage* loops 12a and 12b make investments in flexible and storable backup generation and storage capacity increasingly attractive with increasing percentages of capacity characterised by variable output (such as wind power capacity), or in terms of feedback loop 12a: *percentage variable output capacity* $\xrightarrow[-]{}$ *relative attractiveness investment in new wind power capacity* $\xrightarrow[+]{}$ *investment wind power capacity* $\underset{+}{\nrightarrow}$ *wind power capacity installed* $\xrightarrow[+]{}$ *percentage variable output capacity*; and in terms of feedback loop 12b: *percentage variable output capacity* $\xrightarrow[+]{}$ *attractiveness flexible and storable backup generation and storage capacity* $\xrightarrow[+]{}$ *relative attractiveness investment capacity technology i*[8] $\xrightarrow[+]{}$ generation capacity installed technology i $\xrightarrow[-]{}$ *percentage variable output capacity.*

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[7]Feedback loop 11b: *learning and experience technology i* $\xrightarrow[-]{}$ *specific CO_2 emissions generated technology i* $\xrightarrow[+]{}$ *CO_2 emissions by other generation technologies*, and so on, back to *learning and experience technology i*, and so on.

[8]Only the attractiveness of flexible and storable backup generation and storage capacity is increased, not the attractiveness of technologies characterised by low degrees of flexibility such as nuclear energy.

Feedback loop 13 – the negative *fuel import dependence* loop (-) : This feedback loop only applies to those technologies burning fuels not produced in the EU and makes new capacity investments of these technologies relatively less attractive the more fuel is required by existing plants, or in terms of feedback loop 13: *electricity generated and sold by generation capacity technology i* $\xrightarrow[+]{}$ *fraction fuel i based generation of total* $\xrightarrow[+]{}$ *fuel dependence electricity generation* $\xrightarrow[-]{}$ *relative attractiveness investment capacity technology i* $\xrightarrow[+]{}$ *generation capacity installed technology i* $\xrightarrow[+]{}$ *electricity potentially generated by generation capacity technology i* $\xrightarrow[+]{}$ *electricity generated and sold by generation capacity technology i.*

Feedback loops 14a and 14b – the negative *expected TGC and TEC cost* loops (-) and (-) : Feedback loops 14a and 14b –which are strongly related to feedback loops 7a and 7b– are represented in a simplified way in the feedback loop diagram. There it is indicated that the TGC and TEC prices also influence the expectations about the future TGC and CO_2 TEC price and thus the relative attractiveness of new capacity investments, or: *TGCs and TECs price* $\xrightarrow[+]{}$ *expected future TGCs and* CO_2 *TECs price* $\xrightarrow[+]{}$ *relative attractiveness investment in new wind power capacity*, and $\xrightarrow[-]{}$ *relative attractiveness investment capacity technology i* (for fossil fuel and non-renewable technologies), and so on. Both loops are balancing as were loops 7a and 7b. In the simulation model, the *TGCs and TECs price*s do not directly causally influence the *expected future TGCs and* CO_2 *TECs price*s. The latter are estimated roughly using the *expected demand in5y*, the *expected total potentially generated wind energy*, the *expected average TEC price in5y*, but with the current *specific* CO_2 *emissions of electricity generated* and *specific* CO_2 *emissions* of the different technologies.

Feedback loop 15 – the negative *demand elasticity* loop (-) : Electricity demand is somewhat dynamic in this model –although electricity demand structures are not elaborated in detail– through the negative demand elasticity loop, increasing electricity demand raises –ceteris paribus– electricity prices, which in turn, but only after some time and rather inelastically decrease electricity demand: *electricity demand* $\xrightarrow[+]{}$ *electricity price* $\xrightarrow[-]{}$ *electricity demand.*

The electricity demand is also influenced by some (exogenous) pressures, such as the *GDP*, *energy intensity* and the greenness of the societal value system[9].

Many other feedback loops, combined feedback loops and technical calculation feedback loops exist in the model but will not be explored explicitly here, but might be noticed in the simulation model discussed in the next section.

2 The System Dynamics Simulation Model – In Detail

Here, the structure of the system dynamics simulation model will be discussed by means of views of the stock/flow diagram, specific equations and initial values. Although there are many views and variables in the model, there are also many very similar structures, for example to model the 9 different generation technologies included in the model. Not all structures, variables and equations will be discussed in detail in order to avoid repetition, but a revised version of the model will soon be made available on the internet.

2.0.1 The Wind Power Capacity View

At the right-hand side bottom of figure 3, three related stock-flow structures are visible which keep track of the *wind power capacity installed* –starting from an initially installed capacity at the beginning of 2006 of 33.566 GW (European Commission 2006)–, the annual *total potentially generated wind electricity* and the *capital invested in wind power*, all three fuelled by the *investment* in *wind power capacity*, which is possibly constrained by a fourth stock-flow structure representing

[9]The *greenness societal value system* $\xrightarrow[+]{}$ *effectiveness DSM and REU* $\xrightarrow[-]{}$ *electricity demand.* The effectiveness of DSM and REU works marginally on the expected growth rate of the electricity demand.

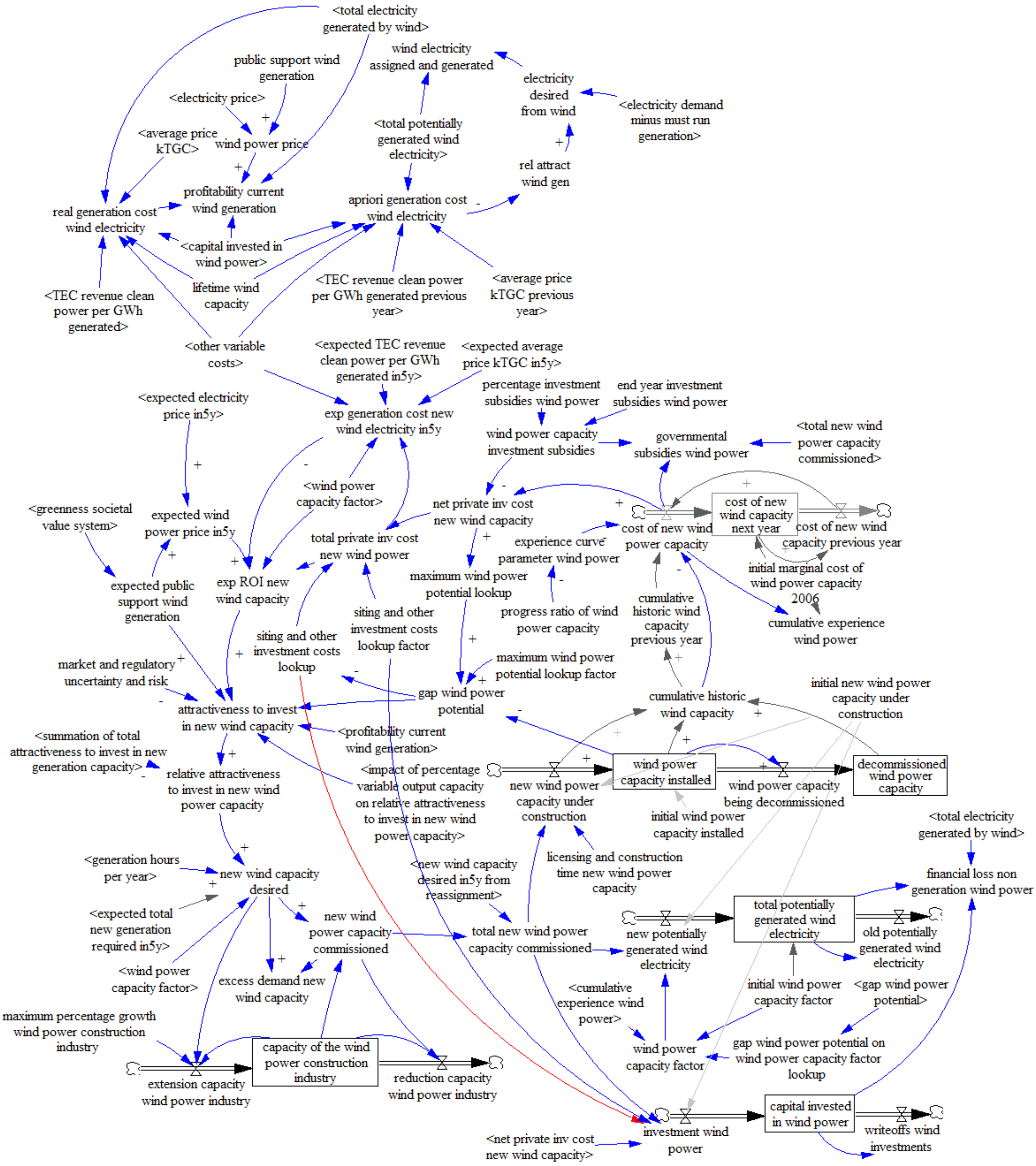

Figure 3: The stock-flow diagram of the wind power module of the EU-25 wind power model

the *capacity of the wind power construction industry.* This *capacity of the wind power construction industry* is a key driver of the models discussed in the previous chapters, also in case of decreasing electricity demand, which could be seen as push instead of pull. This is not the case here. Here the *capacity of the wind power construction industry* is merely damping the growth if the industry expands too rapidly.

The *decommissioned wind power capacity* is also kept track of in order to calculate the *cumulative historic wind capacity*[10] and from that, the *cost of new wind power capacity.* This *cost of new wind power capacity* is part of a stock-flow structure which introduces gradual[11] endogenous technological change and learning by means of experience curves of the form:

$$C_t = C_{t-1}\Big(\frac{X_t}{X_{t-1}}\Big)^e$$

where C_t stands for the cost of a wind turbine of one GW sold at moment t and X_t for the *cumulative* amount of wind power capacity (in GW) ever sold, and e for the *experience curve parameter* which is equal to $-log_2$`(progress ratio)`. A progress ratio of for example 0.9 means that the price of one GW sold – of initially 900 million €/GW[12]– is reduced to 90% of its previous level after a doubling of cumulative sales (International Energy Agency 2000). So the learning rate equals $1 -$ `(progress ratio)`. And *cumulative experience wind power* –which equals the *cost* of *new wind power capacity* over the *initial cost* of *new wind power capacity*– could be seen as a proxy of cumulative learning and experience and is used here to render the technological improvement of the *wind power capacity factor* endogenous.

Most of the other variables and constants in this view are used to calculate costs used to assign the power generation (*wind electricity assigned and generated* and *total electricity generated by wind*) and the expected profitability used to assign new power capacity investments (*new wind capacity desired*) according to the relative attractiveness of the respective power technologies. The relative attractiveness to invest in new wind capacity is also influenced by the gap between the *wind power capacity installed* and the *maximum wind power potential lookup*: the closer the *wind power capacity installed* gets to the *maximum wind power potential*, the higher the *siting and other investment costs*, and the lower the *attractiveness to invest in new wind capacity.*

The *greenness of the societal value system*[13] also influences the *expected public support wind generation* and therefore also the *attractiveness to invest in new wind capacity* and the *expected wind power price in5y.*

2.0.2 Other Power Technologies

The other power technology structures are slightly less detailed and differ somewhat from the wind energy structures just explained. Technologies considered here are conventional gas-based power generation (see figure 4), coal-based power generation (see figure 5) and nuclear-based power generation (see figure 6), potentially future clean coal power generation (see figure 7), renewable biomass power generation (see figure 8), photovoltaic power generation (PV) (see figure 9), and to a lesser and less detailed extent hydro power generation (see figure 11) and geothermal power generation. Other generation technologies could of course be added modularly to this model if they are considered potentially/sufficiently important for the dynamics of wind energy in the EU-25 context. Although the structures shaping the development and use of these other technologies are very similar, they also differ from each other when it comes to important details. This is why these technologies are all modelled explicitly in separate views instead of in one single subscripted

[10]The *cumulative historic wind capacity* is the sum of the *new wind power capacity under construction*, the *wind power capacity installed* and the previously *decommissioned wind power capacity.*

[11]Structural change could be modelled simplistically by means of temporarily different learning curve parameters.

[12]Recent capital cost estimate of wind electricity generation technologies are €900–1,100/GW for onshore wind turbines and €1,500-1,600/GW for offshore wind turbines (International Energy Agency 2003, p349).

[13]If the *greenness of the societal value system* equals 100%, then electricity demand is reduced 2% per year from what it would have been otherwise, if the *greenness of the societal value system* = 50%, then electricity demand is reduced 1% per year from what it would have been otherwise, and so on.

structure. Only the structures and equations of *conventional gas-based power generation* and the most notable differences in structure of the other technologies will be discussed.

Another potentially important development in electricity generation –although not an electricity generation technology as such, but which could be seen as one– is the development of storage technologies (for example hydrogen generation) which could disconnect the variability (intermittence) of demand and supply and allow intermittent technologies such as wind power to grow to higher degrees.

Conventional gas-based power generation: Four stocks are used in the *Thermal Power Capacity (Gas)* view to keep track of *gas power capacity installed*, the *decommissioned gas power capacity* and the *capital invested in gas power*, and to calculate the *cost of new gas capacity next year* of conventional gas-based power generation (see figure 4). The *capacity of the construction industry* is not kept track of because it is assumed that the gas-based power construction industry is sufficiently big to construct any amount of new gas-based power plants. And the *total potentially generated electricity* is not kept track of by means of a stock-flow structure because the technology is assumed to be mature and not to improve spectacularly which means that –in terms of the model– the capacity factor does not improve.

The variable *cumulative historic gas power capacity* is the sum of the *new gas power capacity under construction*, the *gas power capacity installed*[14], the *decommissioning gas power capacity* and the *decommissioned gas power capacity* and is used to calculate the *cost of new gas power capacity* –starting in the base case from an initial average[15] cost of 500M€/GW– by means of the experience curve formula previously discussed and a *progress ratio of gas power capacity* of 0.85 in the base case. The *expected average generation cost new gas power in 5y* is then calculated as *cost of new gas power capacity*/(*generation hours per year* * *capacity factor gas* * lifetime gas *capacity*) + *average fuel cost gas* + *other variable costs* + *exp average price kTGC in5y* * *percentage TGC required in5y* + *exp TEC cost gas power per GWh generated in5y.*

The *average fuel cost gas* is estimated roughly from the 2003 OECD Europe[16] natural gas price for electricity generation of 179.3 current US$/toe –fluctuating between 140 and 179.3 current US$/toe since 1978 (International Energy Agency 2005a, p79)– and the conversion rate of 1 toe = 1/86 GWh and a US$/€ rate of 1, which gives 2003 OECD Europe natural gas prices for electricity generation of about 15420 €/GWh (or between 12040 and 15420 €/GWh since 1978).

The proxy variable *expected ROI*[17] *new gas capacity* is then calculated as (*expected market price electricity in5y* * *flexibility premium* - *expected average generation cost new gas power in 5y*) * *capacity factor gas* * *generation hours per year* / *cost of new gas power capacity.* The *attractiveness to invest in new gas capacity* is calculated as MAX(*expected ROI new gas capacity* * (1 + *profitability of current gas generation*) * *attractiveness flexible and storable backup generation and storable capacity* * *fuel dependence electricity generation by gas lookup* ,0). The MAX(. . . ,0) function is used in order to make sure that the sum of the *attractiveness to invest* variables of all generation technologies is not distorted by technologies with negative ROIs: by using the MAX(. . . ,0) function, these technologies with negative ROIs are not considered for additional capacity investments. It should also be clear that the *profitability of current gas generation* plays a rather modest role in the calculation of the *attractiveness to invest in new gas capacity* because the model does not contain a detailed financial module.

The *flexibility premium* has been added (only) to the conventional gas-based power structure because the generation assignment and investment assignment structures do not take the flexibility of generation or the peak/base-distinction of generation into account, which is a rather important

[14] Initially estimated roughly as 163GW from (European Commission 2006) and (International Energy Agency 2005a).

[15] Recent capital cost estimates of several gas-based electricity generation technologies (International Energy Agency 2003, p349): gas combined cycle (€400–600/GW), centralised gas turbines (€350–450/GW), distributed gas turbines (€700–800/GW).

[16] The OECD Europe and the EU-25 differ in that OECD Europe additionally comprises Iceland, Norway, Switzerland and Turkey, and the EU-25 additionally comprises Cyprus, Estonia, Latvia, Lithuania, Malta and Slovenia.

[17] ROI stands for Return on Investment

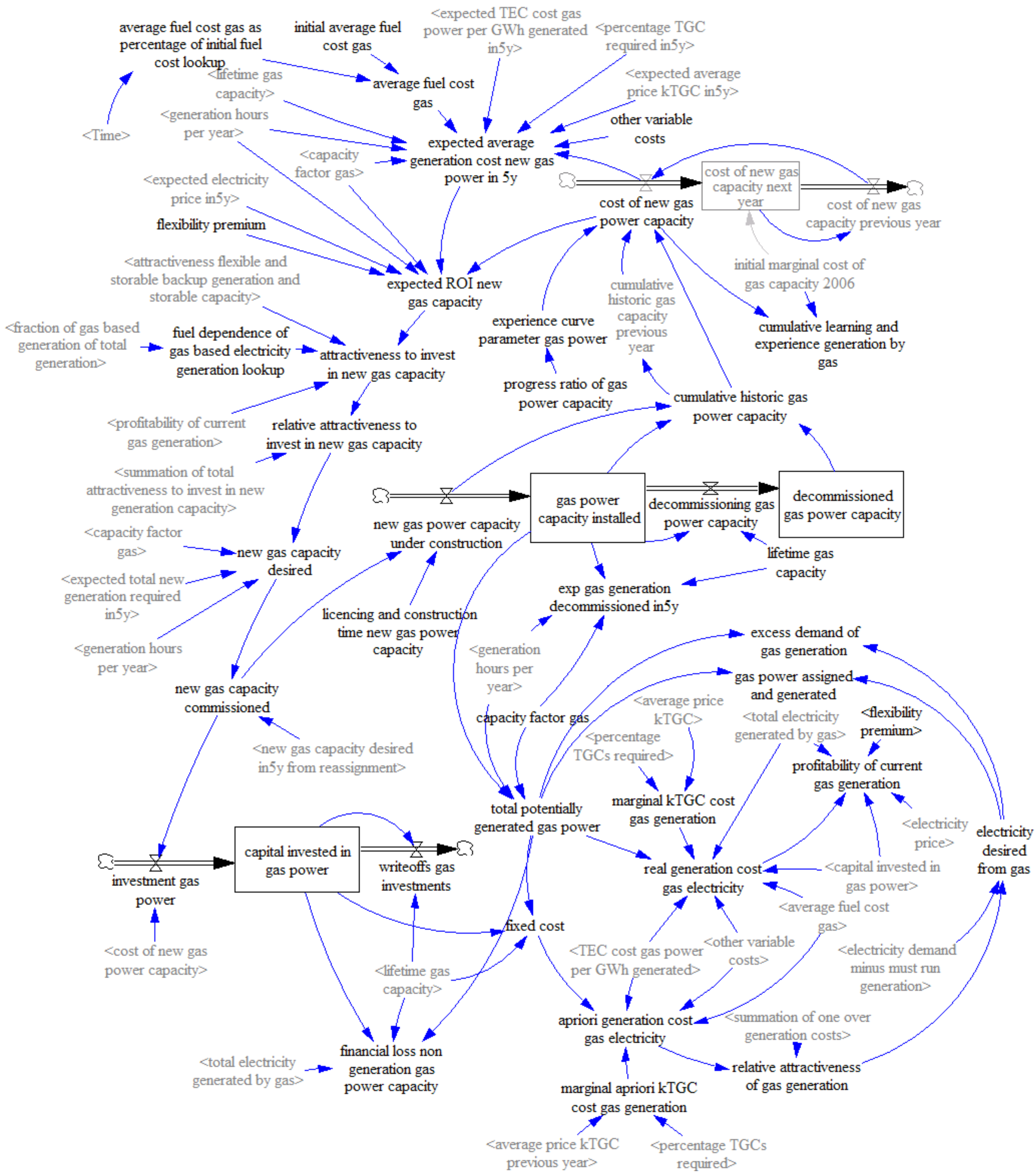

Figure 4: The stock-flow diagram of the conventional gas based power module of the EU-25 wind power model

aspect of gas-based electricity generation. This simplistic *flexibility premium* is a proxy of the additional benefits reaped by flexible generation technologies and is also seen in reality. The model is rather sensitive to different flexibility premia as will be shown in the sensitivity analyses. The flexibility premium used in the base simulations equals 10%.

Conventional coal-based power generation: The conventional coal based power generation module (see figure 5) differs only slightly from the gas based power generation module. The initial values and constants –such as the *initial marginal cost of coal capacity 2006* of 1100 M€/GW[18], the *initial average fuel cost coal*[19], the initial *coal power capacity installed* of 244GW[20] and the *coal power capacity decommissioned*, the *capacity factor coal* and the *initial specific CO_2 emissions coal*– first of all differ from those of gas based power generation. A second difference is that the attractiveness of new coal generation capacity is not penalised by a high actual dependence on coal as is new gas generation capacity by a high degree of gas based electricity generation by means of the *fraction of gas based generation of total generation* and the *fuel dependence of gas based electricity generation lookup.*

A third difference is that if at least 20% of coal capacity is not used for more than 2 consecutive years, then part of this *coal capacity idle for 2 years* –initially 10%– is conversed to biomass capacity by the flow variable *premature conversion coal to biomass capacity*[21]. The corresponding *capital invested in coal power* is written off by means of the variable *additional prematurely decommissioned coal capacity write-offs.*

Conventional nuclear-based power generation: The *total potentially generated nuclear power* by the *nuclear power capacity installed* –of initially 133 GW (European Commission 2006)– is lower than the amount of *electricity desired from nuclear* because of the relatively low variable generation costs and consequent bid prices such that the entire *total potential nuclear generation* is sold and nuclear could be considered 'must-run' generation. The generation costs of existing capacity are relatively low –in spite of additional *future nuclear waste storage costs*– because of the low *average nuclear fuel cost* and the low *average capital cost nuclear generation* due to the largely written-off capital (for about half in the model). The *generation cost of nuclear power* remains relatively low as long as the exogenous[22] variable *public support nuclear power* seriously limits the *relative attractiveness to invest in new nuclear capacity* and consequently the *new nuclear capacity desired* and the *new nuclear power capacity commissioned.* If this is not the case and sufficient *new nuclear power capacity* is commissioned at recent capital cost estimates of about 2000M€/GW (1700–2150M€/GW (International Energy Agency 2003, p349)), then the average *capital costs of nuclear generation* will increase and make nuclear generation somewhat less interesting to invest in –in spite of the experience curve effects and the progress ratio of 0.85. But even in that case will nuclear generation be treated in the current model as must-run generation given its rather inflexible character and low variable generation cost. Nuclear electricity generation is also assumed to be insufficiently flexible to be considered an interesting backup technology for intermittent generation, hence, it is not causally influenced by the *attractiveness flexible and storable backup generation and storable capacity.* And in the model, nuclear generation does not

[18] Recent capital cost estimates of several coal-based electricity generation technologies provided by (International Energy Agency 2003, p349) are: 800–1300 M€/GW for conventional coal, 1100–1300 M€/GW advanced coal, and 1300–1600 M€/GW for coal gasification (IGCC). The *initial marginal cost of coal capacity 2006* used in the model is 1100 M€/GW.

[19] The *initial average fuel cost coal* is estimated roughly from the 2003 OECD Europe steam coal price for electricity generation of 77.5 current US$/toe (between 62US$/toe and 107US$/toe since 1978) (International Energy Agency 2005a, p78), a conversion rate of 1 toe = 1/86 GWh, and a US$/€ rate of 1, which gives 2003 OECD Europe steam coal prices for electricity generation of 6665 €/GWh (or between 5332 and 9202 €/GWh since 1978).

[20] Roughly estimated from (European Commission 2006) and (International Energy Agency 2005a).

[21] *premature conversion coal to biomass capacity* = IF THEN ELSE(*coal capacity idle for 2 years*/*coal power capacity installed*>0.2, coal capacity idle for 2 years * percentage premature conversion idle coal to biomass capacity, 0)

[22] This variable is kept exogenous –although it could be turned into an endogenous variable– because of the major political and public support required to revive nuclear power in Europe.

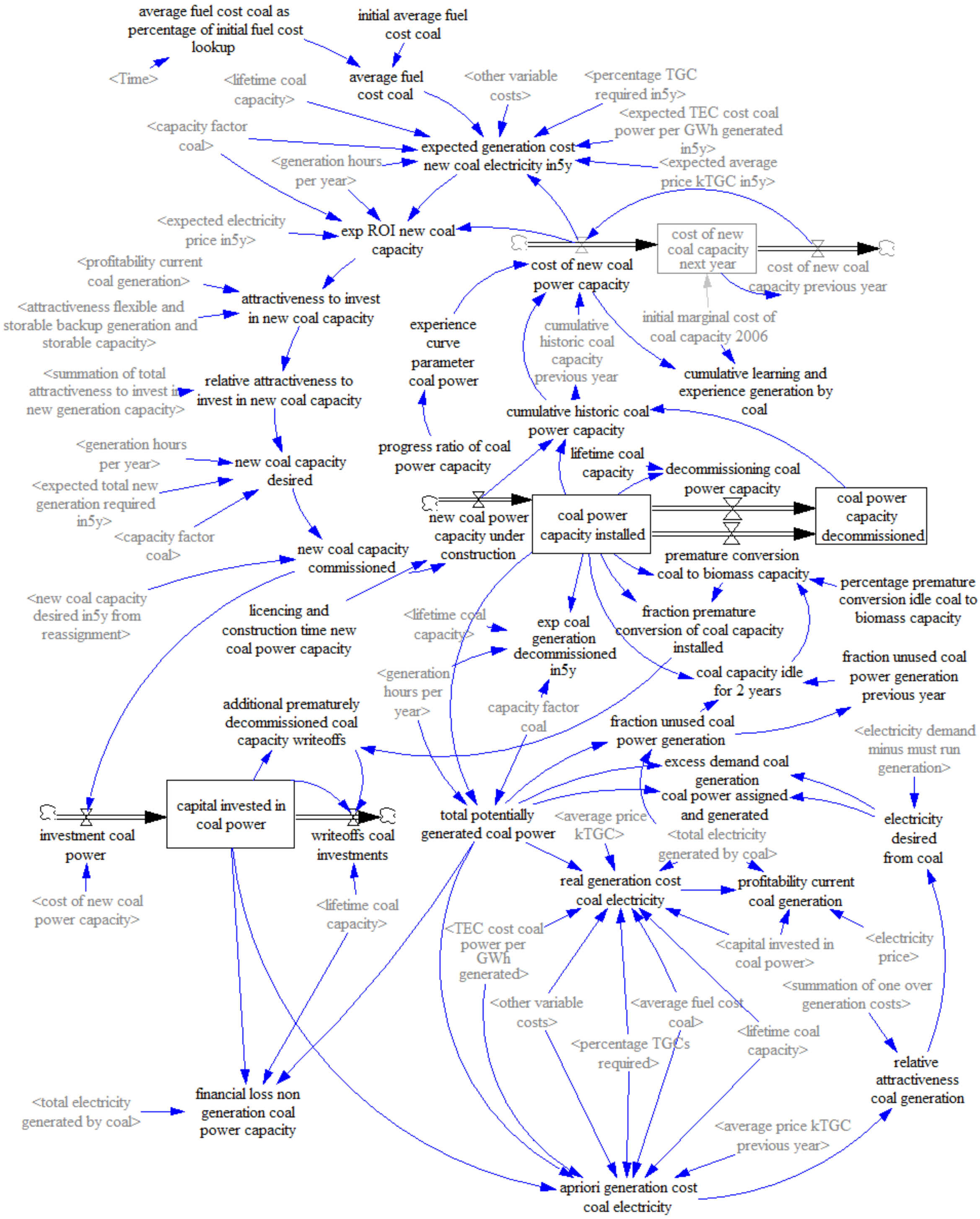

Figure 5: The stock-flow diagram of the conventional coal based power module which is very similar to the conventional gas based power module

Table 1: Minimal net nuclear electricity capacity in OECD Europe compared to the minimal net nuclear capacity of the EU-25 in the model

	2006	2010	2015	2020	2025	2030	2050	2100
Minimal net nuclear capacity in OECD Europe (Nuclear Energy Agency 2005)	(133,0)	112,3†	100,6†	23,6†	16,8†			
Nuclear power capacity installed if gradually decommissioned by a normal *lifetime* (40y)	133,0	120,3	106,2	93,7	82,7	72,99	44,3	12,3
Nuclear power capacity installed if gradually decommissioned by a longer *lifetime* (50y)	133,0	122,8	111,1	101,2	92,7	89,9	63,3	24,7
Nuclear power capacity installed if gradually decommissioned by a shorter *lifetime* (30y)	133,0	116,4	98,5	83,9	71,7	61,6	33,0	6,2

† Data for Sweden unavailable from 2010 on, for Spain from 2015 on, for France from 2020 on, for the UK from 2025 on.

yield TGCs (which means that the applicable *percentage TGCs required* needs to be bought) nor TECs but does not incur any CO_2 TEC costs since it does not emit CO_2.

The *nuclear power capacity installed* is decommissioned gradually by 1/*lifetime nuclear capacity* of 40 years in the base case, of 30 years in case of more rapid –but still gradual– decommissioning, and of 50 years in case of less rapid decommissioning (see table 1). The table lookup variable *additional decommissioning nuclear capacity* allows the abrupt decommissioning of nuclear capacity to simulate the effect of abrupt phase-outs –as planned by several EU25 countries.

Potential clean coal power generation: *Clean coal power* –coal-based electricity generation with CO_2 capturing and storage– which might become a reality in the coming years or decades, differs slightly from the *conventional coal power* discussed before, starting with the initial values ranging from the amount of *clean coal power capacity installed*[23] to the *cost new clean coal power capacity*. The structures of the generation costs of new clean coal power differ from those of conventional coal power in case of TEC or tax schemes, which yield *revenues* or –as in this model– *negative costs* for clean coal generation whereas they yield costs for conventional coal generation.

The fuel costs of this clean coal are somewhat higher than those of conventional coal: the *additional fuel cost clean coal* is initially taken to be 10% of the *average fuel cost coal*. However, the costs of clean coal power could be expected to be even higher due to the necessary CO_2 capturing and storing. Initially, these costs are not taken into account, but they are looked at in the sensitivity analyses.

Another difference with conventional fossil fuel technologies is that exogenous structures have been added such as the *initial investment in clean coal capacity* to bring about the take-off of this new technology which is of course not necessary in case of the mature conventional coal capacity.

Although *clean gas* –such as the planned BP hydrogen power plant in Scotland– will most certainly see the light too, it has not been included in the model because of the very likely risks of overdependence on gas and depletion of gas resources which are less problematic in the case of coal. If *clean gas* power generation becomes technically feasible and economically viable, then most likely will *clean coal* power generation –which has an even bigger potential of clean electricity generation– too. Today, BP and the Edison Mission Group plan to bring online a low-carbon power generation plant in California using petroleum coke by 2011. This would open the path to clean coal power generation on a commercial scale.

Biomass-based power generation: The biomass-based power view is very similar to the previous clean coal power view. There are two important differences.

The first major difference is that a static *maximum biomass power capacity potential* –of 500GW in the base runs– influences both the generation cost of biomass electricity (and hence the amount generated) via the *gap biomass potential*, as well as the investment in new biomass capacity

[23] The initial value of *clean coal power capacity installed* is –although no industrial clean coal plants are currently online– taken to be 1GW, just to make sure that *denominators* are not equal to 0. This is also why several equations are secured by means of the MAX and IF-THEN-ELSE functions.

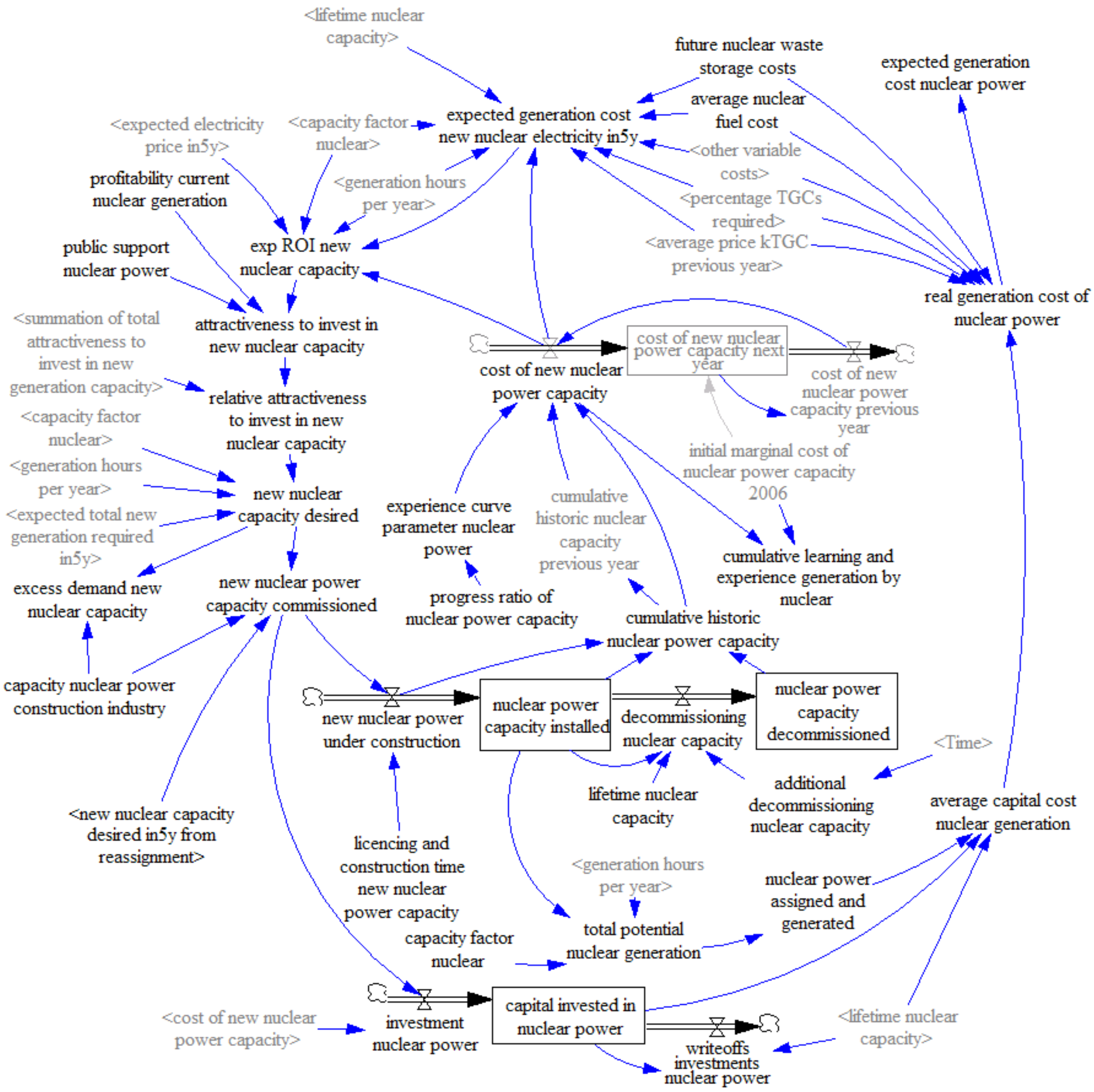

Figure 6: The stock-flow diagram of the nuclear power module

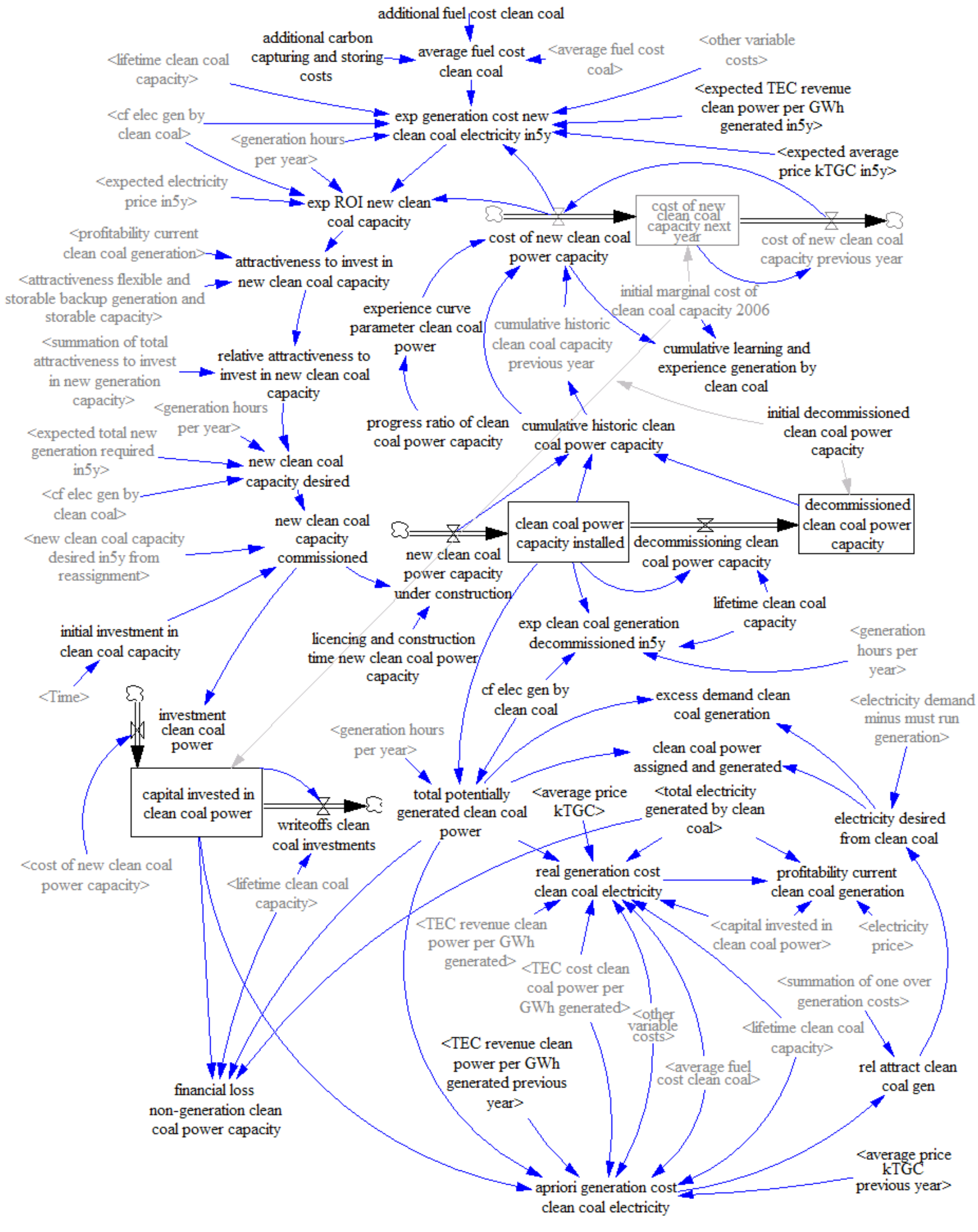

Figure 7: The clean coal view of the stock/flow diagram

via the *expected gap biomass potential*, by increasing the *(expected) average fuel costs of biomass* by means of the *average fuel cost biomass via gap lookup.* The *average fuel cost biomass via gap lookup* assumes following values in the base runs: ((-1,5), (0, 1.5), (0.5, 1), (1, 0.8)) which means that the average biomass fuel cost is 80% of the full price when there is no biomass-based electricity generation capacity in place, is 100% of the full cost when half the maximum potential biomass capacity is in place, 150% if the maximum potential capacity has been reached, and even more if it peaks above this initial maximum potential capacity. This structure alone leads –in the absence of other structures curtailing the biomass capacity expansion– to severely oscillating investment behaviour –not only for investments in biomass capacity but for other generation capacities too– when the biomass capacity –initially 11.549 GW (European Commission 2006)– approaches and exceeds the maximum potential, imposed by the maximum available biomass fuel. But a direct link has been added to the model between the *expected gap biomass potential* and the *attractiveness to invest in new biomass capacity* in order to damp these extreme oscillatory patterns. Adding this structure leads to a smoother evolution without heavy booms and busts. It could be argued that real-world information about the future availability of biomass will become an important aspect of the decision to invest in biomass power capacity once the maximum potential is being approached.

The second major difference is that 10% of the coal power plants which are not used for more than two years and which are therefore decommissioned before the end of their lifetimes, are transformed to biomass power plants –by the variable *premature conversion coal to biomass capacity*– at the cost of the *additional prematurely decommissioned coal capacity writeoffs*, which is lower than the costs of newly build biomass power plants of about 2000M€/GW (1,500–2,500M€/GW according to the International Energy Agency (2003, p349)). These conversed plants are assumed to be 100% biomass plants –which is of course a simplification of reality– and therefore receive the full amount of TGCs and TECs.

Solar Photo Voltaic: European Photo Voltaic (PV) power has been growing by about 35% over the last couple of years[24] in spite of the relatively high marginal investment cost of about 6,000–7,000 M€/GW for distributed photovoltaic and 4,000-5,000 M€/GW for centralised photovoltaic (International Energy Agency 2003, p349). But these costs are falling rapidly. Thin film PV power technology might –within a couple of decades– become a major power generating technology. However, the future large scale deployment of this technology is not certain. As for now, costs are still prohibitive for a large scale deployment. This makes that PV power –contrary to wind power– is currently only viable in niche markets or in case of extensive governmental subsidies. Given the high uncertainty/riskiness, a scenario/controlled simulation approach is opted for here. The development of solar PV power generation and its impact on the development of other generation technologies is included endogenously in the model, but it is kept exogenous to the rest of the model which means that the developments of the other generation technologies do not causally impact the development of solar PV power generation. This comes down to the assumption that solar PV power will be mostly installed in a decentralised/distributed mode, independent from centralised generation. The extension of the model with real competition for capacity extensions with the other generation technologies would be very interesting, especially in case of (expected) increasing fuel prices.

Again, the same type of variables –but slightly different connections and functions– are used. First of all are the stock variables *PV power capacity installed* (starting from an *initial PV power capacity installed* of 1.010 GW (European Commission 2006)) and –after an average *lifetime of PV panels* of 20 years in the base case– *decommissioned PV power capacity* used to monitor the capacity and to calculate the *cost of new PV power capacity* decreasing following the experience curve with a *progress ratio of PV power capacity* of 0.75 in the base case. This *cost of new PV power capacity* is used to calculate the *capital invested in PV power* which is monitored separately because of strong cost-reducing experience-curve effects, and which is used in the calculation of the *average generation cost of PV electricity.*

[24]The average annual percent change of solar PV between 1990-2003 was 34,5% in the OECD EUROPE and 35,9% in the EU-15 (International Energy Agency 2005b).

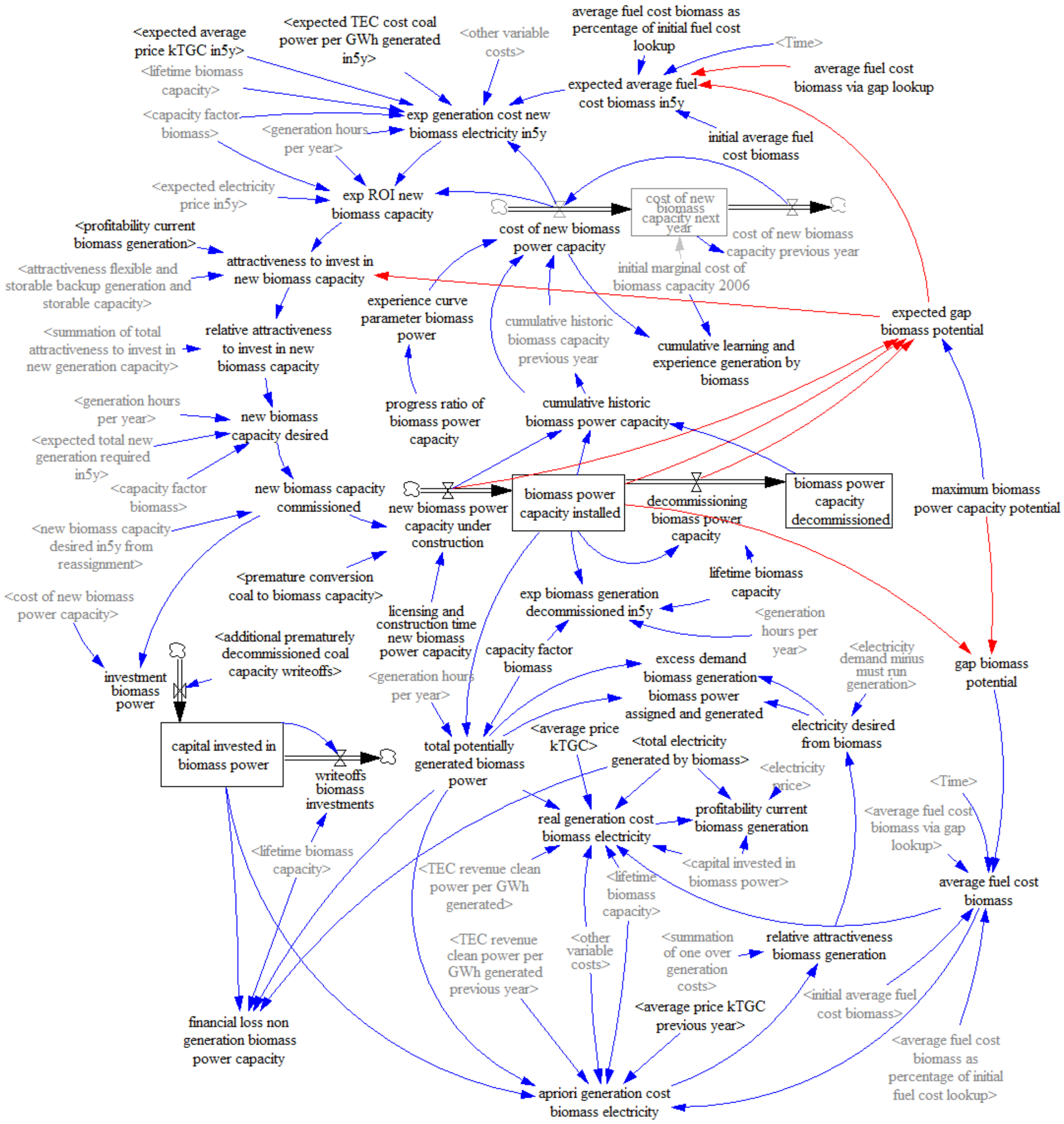

Figure 8: The biomass view of the stock/flow diagram

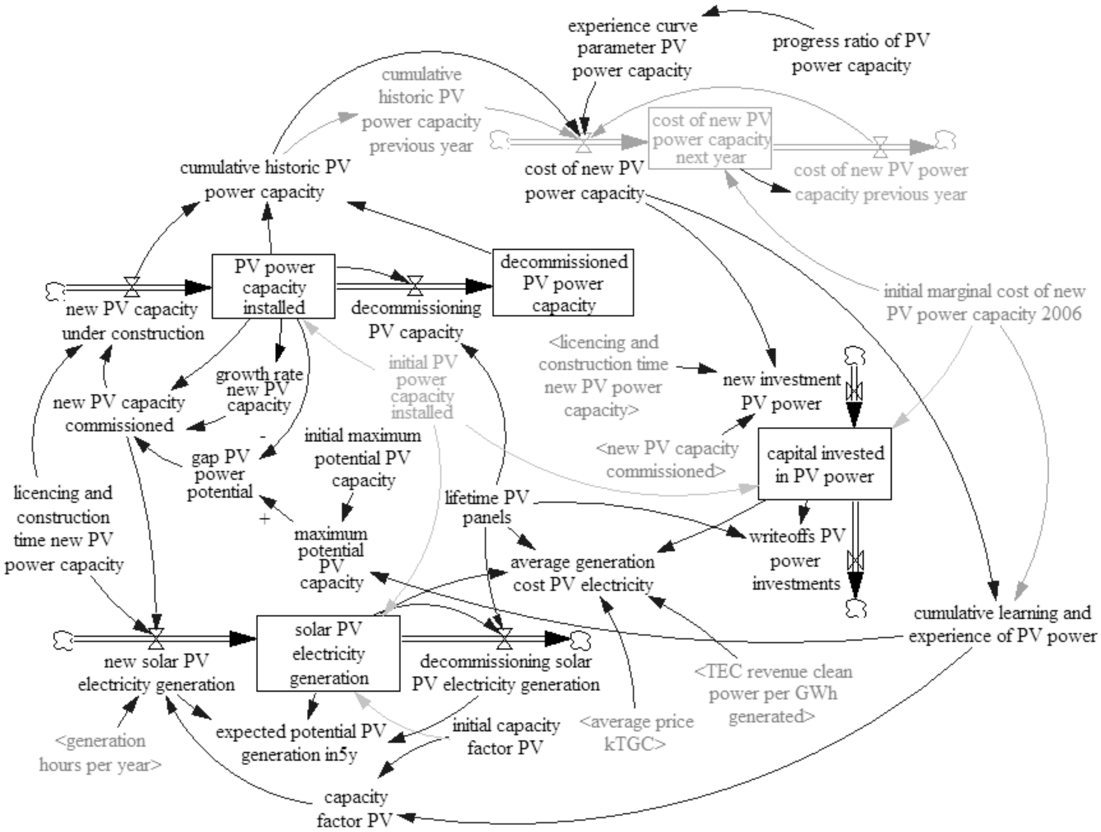

Figure 9: The solar PV generation capacity view

The increasing *cumulative learning and experience of PV power capacity* –equal to (1 - *cost of new PV power capacity / initial cost of new PV power capacity*)– slightly increases the *capacity factor PV* as well as the *maximum potential PV capacity* from the *initial maximum potential PV capacity.* The increasing *capacity factor PV* increases the *new potentially generated solar PV electricity* of *new PV capacity commissioned* and therefore also the *solar PV electricity generated* –monitored separately because of the dynamic capacity factor, and effectively generated as 'must-run generation' in this version of the model[25]– which decreases the *average generation cost of PV electricity.*

The increasing *maximum potential PV capacity* also increases the *gap PV power potential* which leads in turn to more *new PV capacity commissioned* which drives –after a *licensing and construction time of new PV power capacity* of 1 year– the *new PV capacity under construction*, the *new potentially generated solar PV electricity* and the *new investment PV power*, and so on. Here again, the *new PV capacity commissioned* does not compete directly with the centralised generation technologies for new capacity to be commissioned, so there is no feedback loop with the larger model at this point. The interaction with the larger model might be improved by introducing a variable *cost of new PV power electricity in5y* interacting in a feedback loop with the expected generation price, partly driving the expansion of PV power.

The *average generation cost of PV electricity* is also influenced by the *average price kTGC* and the *TEC revenue of clean power per GWh generated* from the rest of the model. Several variables from the PV view also influence the variables in the rest of the model: *solar PV electricity generated*

[25]PV power does not *compete* for supplying part of the electricity demand: it simply delivers all electricity generated as distributed must-run generation. This means that there is no feedback loop to the other generation technologies at this point.

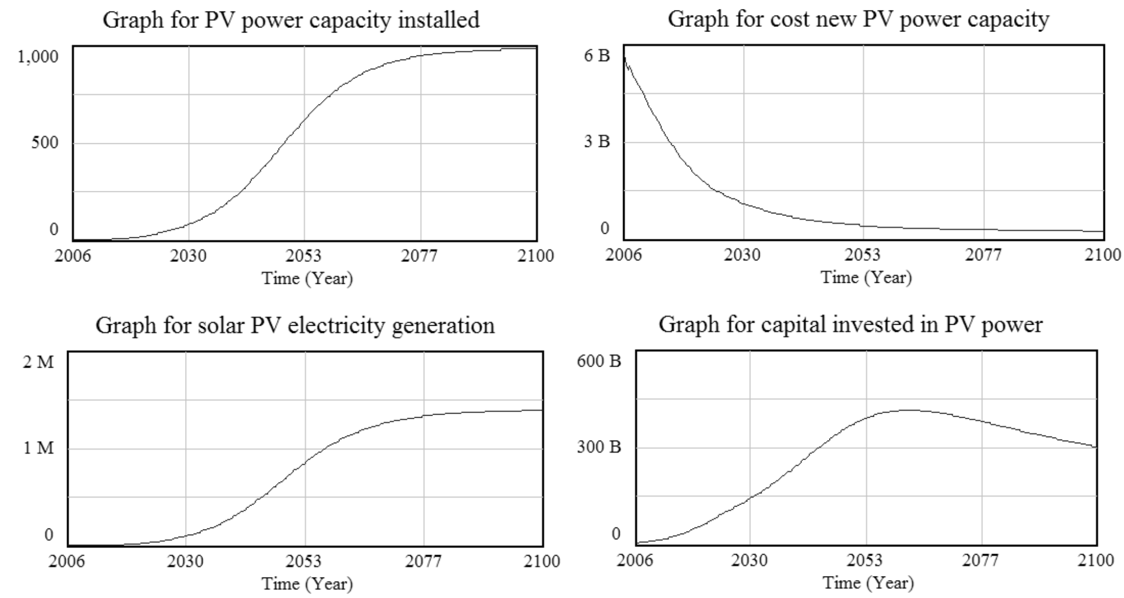

Figure 10: The time-evolutionary behaviour of the solar PV structure

influences the *must run generation* and the *total amount of electricity (potentially) generated*; *PV power capacity installed* influences the *percentage intermittent capacity* and *total capacity installed*; *expected PV generation in5y* influences the *exp TGC supply in5y*. Initially it is also assumed here that the PV power generation does not influence the *electricity market price* of the centralised grid because of its (assumed) purely decentralised/distributed character.

Hydro Power Capacity: On-shore hydro power is modelled rather simplistically in this model: large, small, micro and pumping capacity are treated without distinction[26] and the further development of hydro power is independent from the development of other generation technologies (see figure 11). The latter simplification is made because the maximum capacity of large hydro is about reached which means that further growth will most probably come from distributed (small, micro and some pumping) hydro capacity which will mostly be added by small, local players in a decentralised mode. The *hydro power capacity installed* grows with the annual *new hydro power under construction* which equals the assumed *growth rate new hydro* of 10% times the *hydro power capacity installed* times the *gap hydro power potential* of (1-*hydro power capacity installed/maximum potential hydro capacity*). The assumed *maximum potential hydro capacity* is –in the base case– taken to be double the current *hydro power capacity installed* of 131.440 GW (European Commission 2006). Recent capital cost estimates of hydro electricity generation technology of 1900–2600M€/GW (International Energy Agency 2003, p349) and an assumed lifetime of 40 years are used for generation cost calculation purposes. Future *hydro electricity generated* equals the *hydro power capacity installed* times the current *capacity factor hydro* and the *generation hours per year*.

Although hydro power is almost exogenous to the rest of the model, it still has an influence on the rest of the model, more precisely on the *must run generation* and thus the *electricity demand minus must run generation* and the *electricity desired* from other generation technologies, the *TGC supply*, the *expected TGC supply in5y* via the *expected hydro generation in5y* and the *total expected potential generation in5y*.

[26] A sensible extension of the model might be to split them in order to distinguish pumping capacity and part of large hydro power –which could be used to absorb intermittent/variable output generation– from all other hydro power –some of which *is* variable (seasonal) output generation. They are also often treated differently in terms of TGCs received.

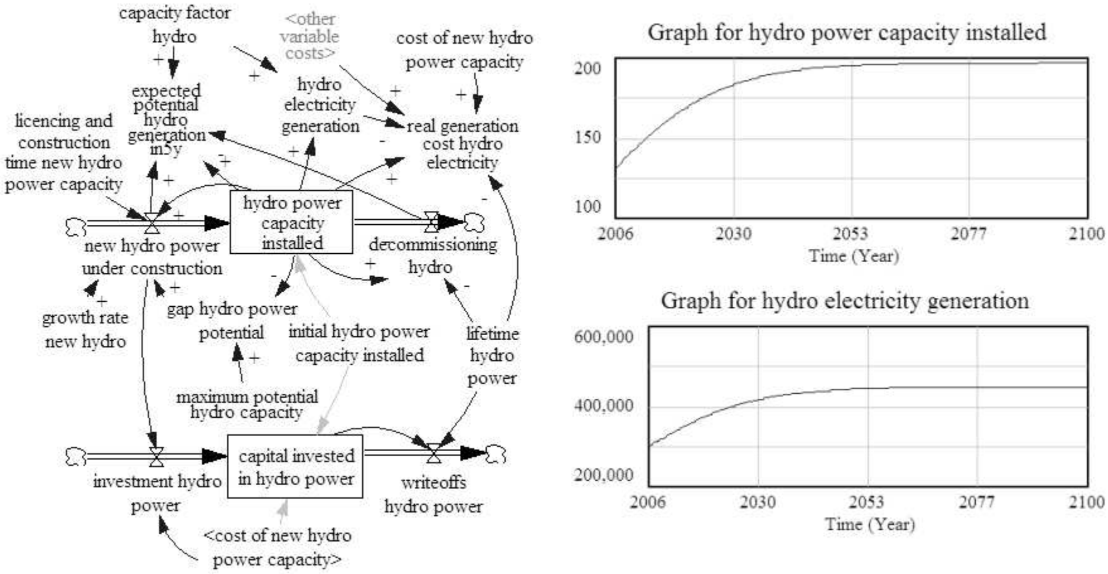

Figure 11: Simplified stock-flow structure and resulting dynamics of the European hydro power capacity installed

Other Generation Technologies: One other relatively less important generation technology is included here, namely current geothermal capacity of 0.695 GW (European Commission 2006) with a *geothermal power capacity factor* of 91%, a recent capital cost estimate of geothermal electricity generation technology of 1,800–2,600 M€/GW (International Energy Agency 2003, p349) and an assumed lifetime of 20 years. This structure could possibly be further developed.

Hydrogen Technology: Hydrogen technology is not so much an energy generation technology, but it could seriously impact the electricity generation sector in at least two ways.

A real breakthrough of hydrogen would first of all make available the necessary technologies to disconnect the double variability/intermittence of demand and supply –which would allow variable-output technology to penetrate with much higher percentages. In the model (see figure 12), the exogenous variable *year real hydrogen or storage breakthrough* allows to switch on the *switch hydrogen or storage breakthrough* (from 0 to 1) which turns both the *impact of percentage variable output capacity on relative attractiveness to invest in new wind power capacity* and the *attractiveness flexible and storable backup generation and storable capacity* back to 1.

The second serious impact of a real breakthrough of hydrogen would be a temporary increase of the electricity demand growth increasing the *electricity demand.* This again could be introduced exogenously in the model by means of the variable *additional growth rate electricity demand by hydrogen breakthrough* added to the *expected growth rate electricity demand.*

2.0.3 Generation Assignment

The generation is assigned in three steps. First, the 'must-run' generation is automatically assigned to generation technologies which are either distributed (for example *solar PV electricity generation*, *hydro electricity generation* and *geothermal electricity generation*) or are inflexible with very low variable costs and have therefore very low bid prices (for example *nuclear power assigned and generated*).

Then, the *electricity demand minus must run generation* is assigned to the remaining 'may-run' technologies –not included in the 'must-run' generation– based on gas, coal, clean coal, biomass, and wind power generation. This first real assignment is taken to be inversely proportional to the

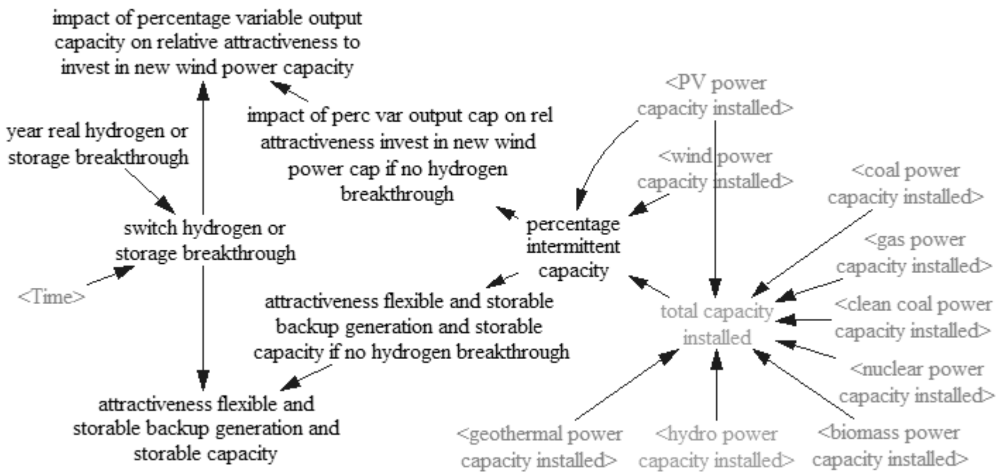

Figure 12: The potential influence of hydrogen technology on intermittent and non-intermittent power generation technologies

*a priori generation cost*s –the generation costs if fully assigned and with TGC and TEC prices of the previous year– of the respective generation technologies. In the case of gas based generation, the *relative attractiveness of gas generation* is for example equal to 1/*a priori generation cost gas electricity*/*summation of one over generation costs*. This *relative attractiveness of gas generation* times the *electricity demand minus must run generation* makes up the *electricity desired from gas*, which could be smaller, bigger or equal to the *total potentially generated gas power*. The amount of *electricity desired from gas* smaller or equal to the *total potentially generated gas power* is assigned in *gas power assigned and generated*, the over-assigned rest is held back as *excess demand of gas generation* which is –together with the excess demands of the other generation technologies– reassigned.

All over-allocated amounts are summed in the variable *total excess demand to be reassigned* which is reassigned by means of the *alloc p* and *market p* functions[27] 'allocation by priority' structure[28] to the remaining potential generation after the first (real) assignment –*available gas generation after the first assignment* in the case of gas based generation (see figure 13). These remaining available amounts of generation are offered to the allocation mechanism by means of the subscripted variable *total available generation possibly to be reassigned after first assignment*. The *width*[29] taken here is one over the *difference in price of importance* of €500/GWh. And the *priority* of each generation technology is again equal to one over the a priori generation cost of that technology. The resulting *generation allocated per technology* is then unsubscripted in the *total excess demand reassigned to generation alloc* –in case of gas based generation in the variable *total excess demand reassigned to gas generation alloc*. And the *total electricity generated by* each of the 'may-run' generation technologies is made up by this *total excess demand reassigned to generation alloc* together with the previously assigned *power assigned and generated*.

A *generation shortage* arises if the *total excess demand to be reassigned* is greater then the sum of the amounts of *available generation after the first assignment*.

This particular structure –which is only one of many possible structures– influences the behaviour of the model. But alternative structures are not explored here.

[27]'to allocate a scarce supply [electricity demand in our case] to a number or requests [generation supplies in our case] based on the priority of those requests' (Ventana Systems 2000)

[28]See Appendix E of the Vensim Reference Manuals.

[29]The *width* 'specifies how big a gap in priority is required to have the allocation go first to higher priority with only leftovers going to lower' *priority* (Ventana Systems 2000).

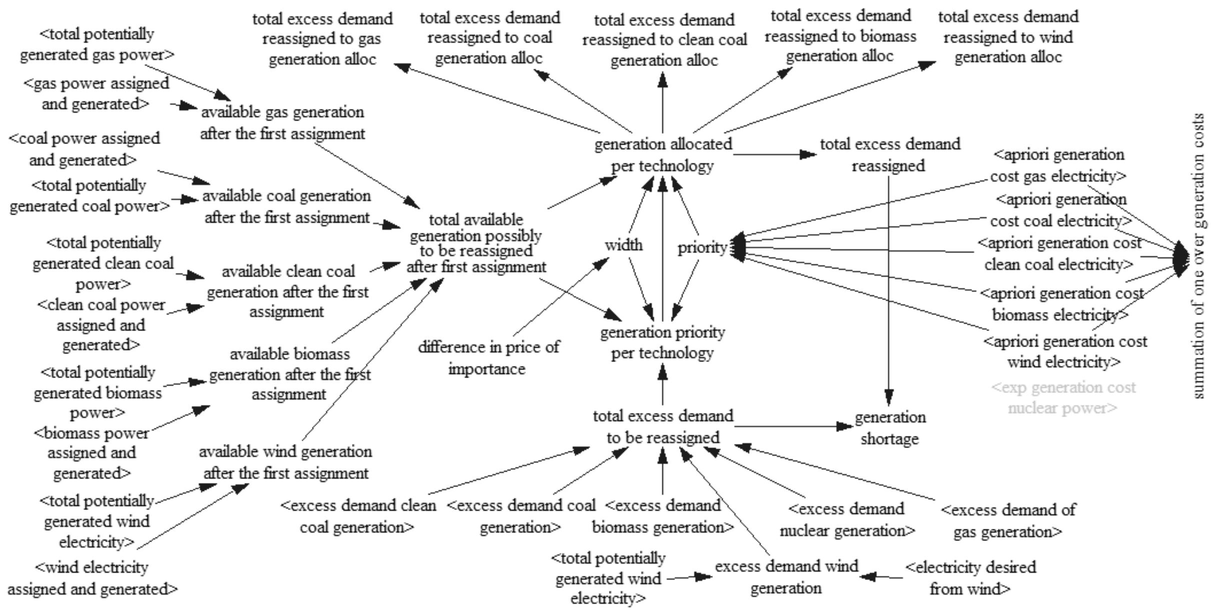

Figure 13: The Stock-flow diagram of the generation assignment to the may-run generation technologies

2.0.4 Electricity Demand, Demand Forecast and Supply Forecast in the Model

The stock variable *electricity demand* –starting from an initial value of 3179000 GWh in 2006 (European Commission 2006)– increases (and potentially decreases) by means of the flow variable *expected additional electricity demand* which is the product of the *electricity demand* and the *expected growth rate electricity demand* (see figure 14). The *expected growth rate electricity demand* is equal to the *GDP growth EU * electricity intensity EU growth + annual percentage decrease electricity demand by spontaneous DSM and REU + annual percentage decrease electricity demand by forced DSM and REU - annual percentage decrease electricity price * price elasticity + additional growth rate electricity demand by hydrogen breakthrough.* The base case *expected growth rate* fluctuates around the 1,9% electricity demand growth rate observed in OECD Europe and the EU-15 between 1990 and 2003 (International Energy Agency 2005b) (which is higher than the 1.3% projected by the International Energy Agency (2004, p218–219) to 2030 for the EU-15). The *GDP growth EU* consists of a *GDP growth EU trend* factor and a smoothed random normal factor *GDP growth EU randomised* which might be used for scenario and sensitivity analyses.

The *expected electricity demand in5y*ears equals the current *electricity demand* times the *expected growth rate electricity demand*[5]. The *total potential generation required in5y* is then the *expected electricity demand in5y* augmented with a *supply margin desired* which is assumed to depend on the scenario variable *degree of real EU-wide competition* determined by the lookup variable *degree of real EU-wide competition lookup.* This *total potential generation required in5y* minus the *total expected potential generation in5y* gives the *expected electricity shortage in5y.* The *expected total new generation required in5y* is then calculated as MAX(*expected electricity shortage in5y*/5,0)*(1+*additional construction margin*). So, the difference between expected demand and expected potential supply within 5 years gives rise to additional investments in new generation capacity.

The aforementioned *total expected potential generation in5y* is the sum of the potentially generated electricity in 5 years by all generation technologies, which are approximated rather well by the respective potential generation plus 5 times the newly commissioned potentially generated electricity minus 5 times the newly decommissioned electricity generation (see the right hand side structure in figure 14). Figure 15 shows the similarity between the approximation 5 years before

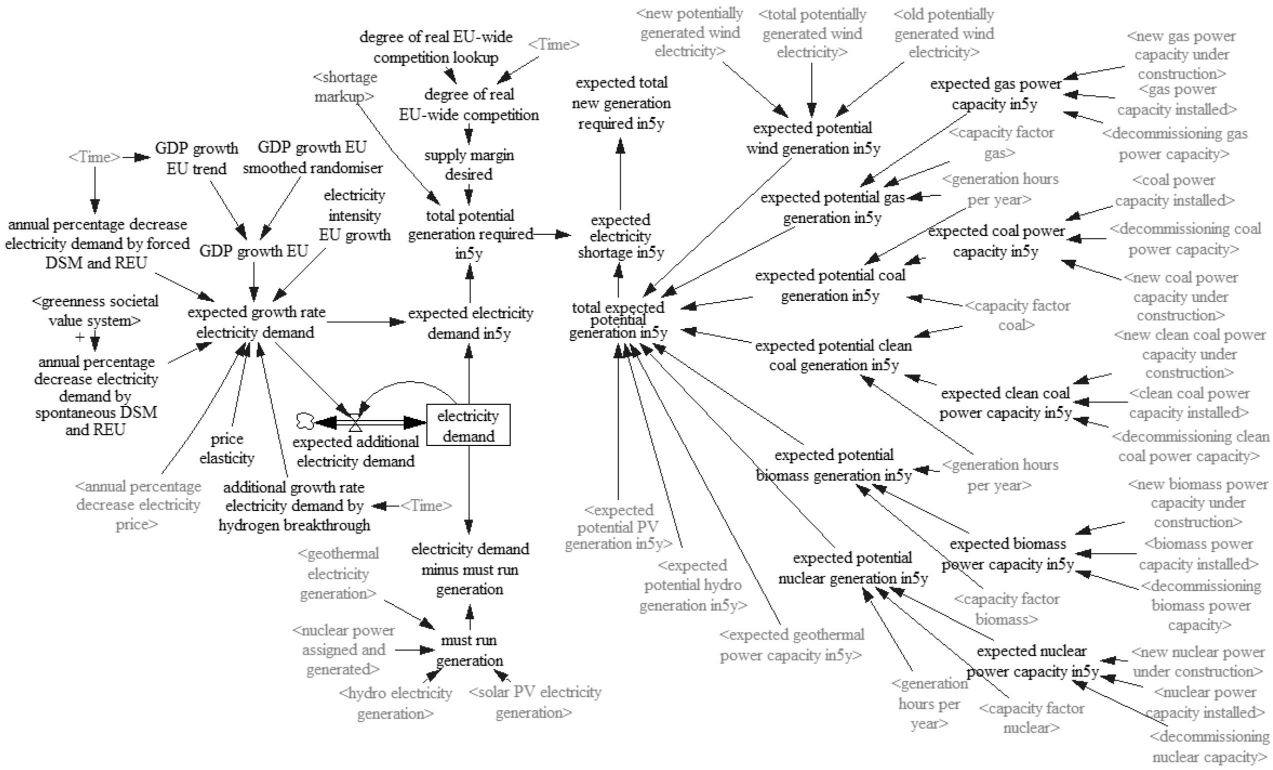

Figure 14: *Electricity demand*, *expected electricity demand in5y*, *total expected potential generation in5y*, and *expected total new generation required in5y*

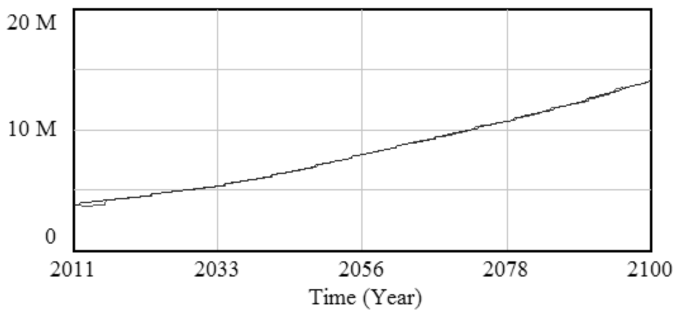

Figure 15: Comparison of the *total potential generation* and the *total expected potential generation in5y* with a delay of 5 years

and the real total potential generation.

2.0.5 Capacity Investment Assignment

The assignment of investments in new generation capacity are rather similar to the generation assignment discussed previously. First, some technologies are 'exogenously' invested in –the distributed solar PV based and hydro based generation capacities.

Then, the *expected total new generation required in5y* is assigned –in the first real assignment– proportionally to the *relative attractiveness to invest in new capacity* which is equal to the *attractiveness to invest in new capacity* of wind-based, gas-based, coal-based, biomass-based, clean coal-based, and nuclear-based[30] power generation capacity, divided by the *summation of total attractiveness to invest in new generation capacity.* The *relative attractiveness to invest in new power capacity* times the *expected total new generation required in5y* divided by the product of the respective *capacity factor* and the number of *generation hours per year* gives the *new capacity desired* of each of the generation technologies.

Again, this particular structure –which is only one of many possible structures– influences the behaviour of the model. But other structures are not explored here.

However, these *new capacities desired* sometimes exceed the capacities of the respective power plant construction industries in which case the capacities actually commissioned are limited to the capacity of the power construction industry. This is sometimes the case for the *new wind power capacity commissioned*[31]. The rest is channelled via the variable *excess demand new wind capacity* to the variable *total excess demand new generation in5y* (see figure 16). This *total excess demand new generation in5y* is redistributed by means of the *alloc p* and *market p* functions over the generation technologies with remaining spare industrial capacity on the basis of the respective *relative attractiveness to invest in new power capacity* of the different technologies and their *available new generation after the first assignment.* This results in the assignment of this excess new capacity demand to the *new capacity desired in5y from reassignment* variables which are additionally commissioned.

2.0.6 Electricity Price

Electricity price levels and specific price structures differ markedly within and between EU-25 member states due to different technological mixes, market structures and other local circumstances. Any pricing mechanism in the model would be a severe simplification of reality because (i) the model is aggregated on the EU-25 level, (ii) it is only simulated a couple of times per year and not per quarter of an hour, and (iii) does not deal with different (electricity) markets. And

[30] if there is sufficient *public support nuclear power*

[31] new wind power capacity commissioned = IF THEN ELSE(new wind capacity desired > 0,IF THEN ELSE(new wind capacity desired < capacity of the wind power construction industry, new wind capacity desired, capacity of the wind power construction industry), 0)

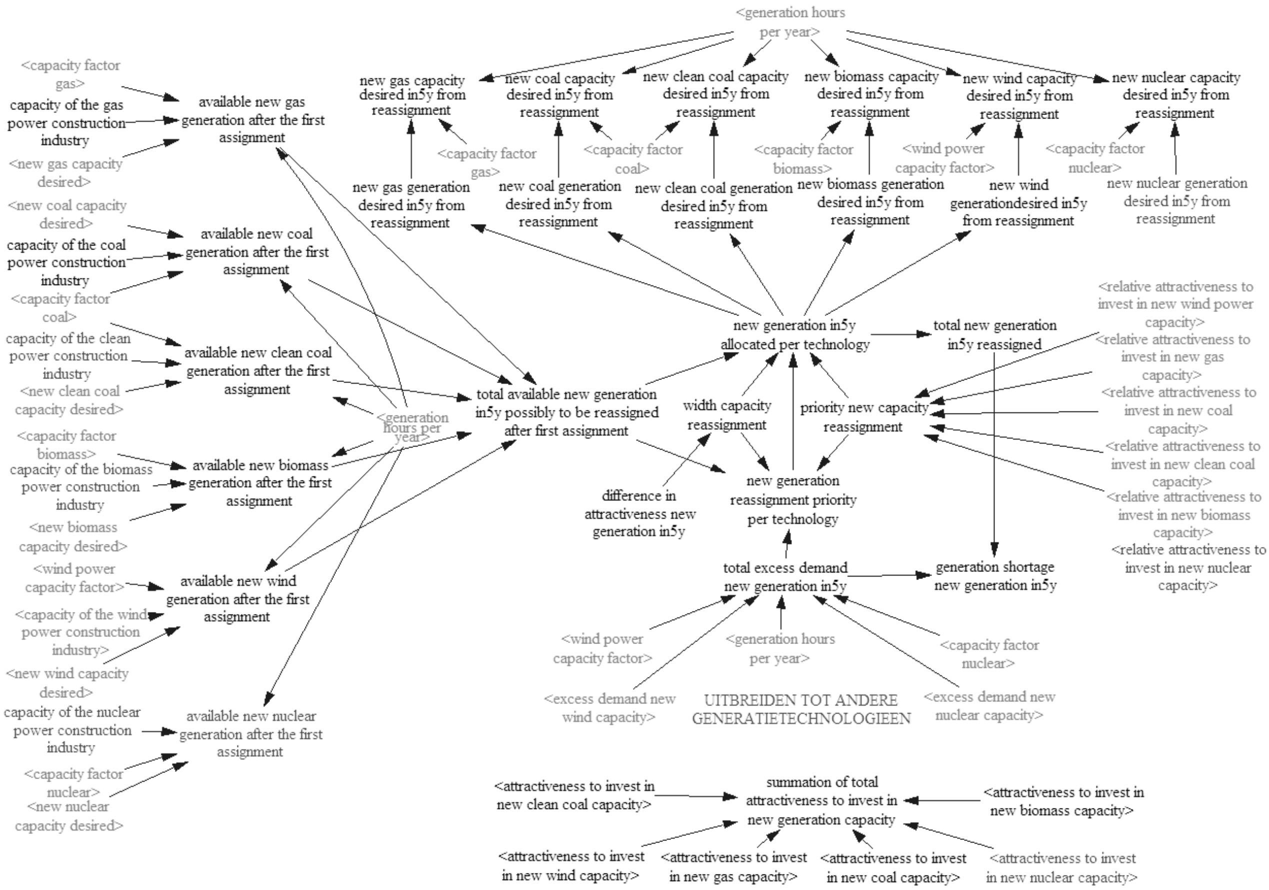

Figure 16: The new capacity assignment and reassignment view

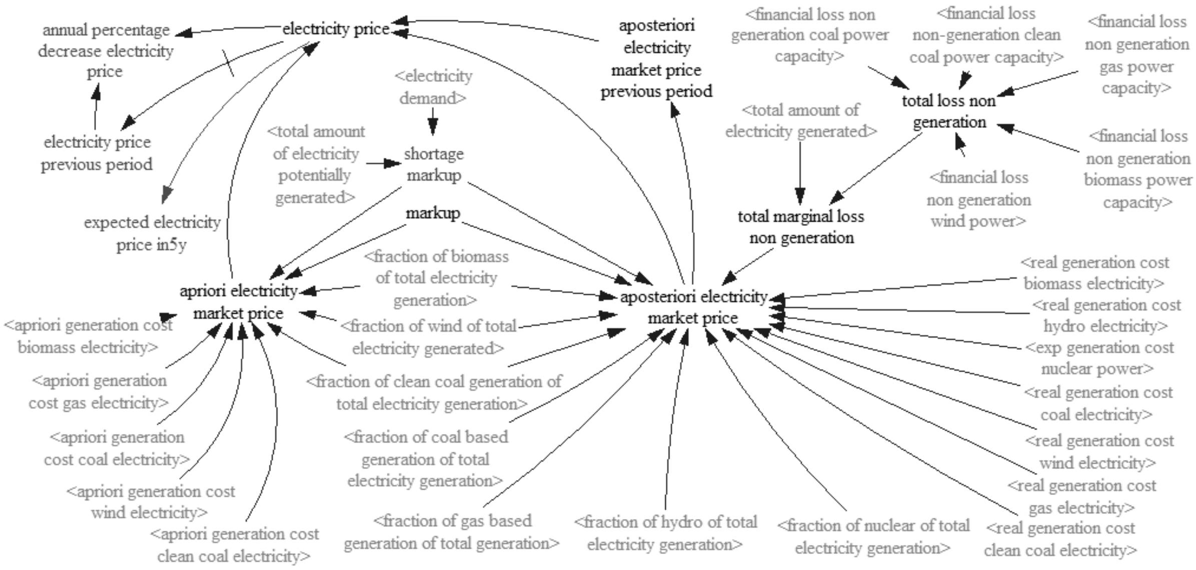

Figure 17: Three price structures and the resulting *electricity price*, *expected electricity price* and the *annual percentage decrease electricity price*

different pricing structures seriously influence the market. This is why the sensitivity of the model and strategies to other price structures is explored as well. Three simple pricing mechanisms and their mixtures could be tested for (see also figure 17): (i) an *a priori electricity market price* –which could be seen as a proxy for a market price– calculated as the maximum of the a priori generation cost of gas, coal, wind, biomass and clean coal power if their generation exceeds 15% of total electricity generated times a *markup* and a *shortage markup* (activated in case of generation shortages); (ii) an *a posteriori electricity market price* –which could be seen as a proxy for benevolent monopolist pricing– which is the sum of *real (ex post) generation costs per technology* times their respective *fractions generated of the total generation* times the *markup* and the *shortage markup* plus the *total marginal loss of non generation*; and (iii) an *a posteriori electricity market price of the previous period* which is nothing more than the *a posteriori electricity market price* lagged by a year. The *annual percentage decrease electricity price* (times the *price elasticity*) in turn influences the *expected growth rate electricity demand* in the demand view. And the *expected electricity price in5y* is taken to be equal to FORECAST(*electricity price*, 5, 10). And the *electricity price* structure used here is equal to 1/3 the *apriori electricity market price* plus 1/3 the *aposteriori electricity market price* plus 1/3 the *aposteriori electricity market price of the previous period*. And there is a general electricity price *markup* of maximum 5% in case of shortages.

2.0.7 Emissions and Schemes

The 'Emissions and Schemes' view contains variables and calculations concerning the Tradable Green Certificates and Tradable Emission Certificates (see figure 19).

The *average TGC price*, *average price kTGC*, *average price kTGC previous year* and the *expected average price kTGC in5y* are calculated from the *TGC supply*[32] from green generation and *TGC demand* from the *total amount of electricity generated* times the exogenously enforced *percentage TGCs required*, and the exogenous *minimum TGC price* and *maximum TGC price*.

Figure 19 shows the part of the model where the TEC revenues and costs, the fuel uses and the (specific) CO_2 emissions are calculated from *electricity generated*, the *specific CO_2 emissions* and *marginal fuel uses* and the *TAX/TEC price lookup*.

[32]In which clean coal is not included here.

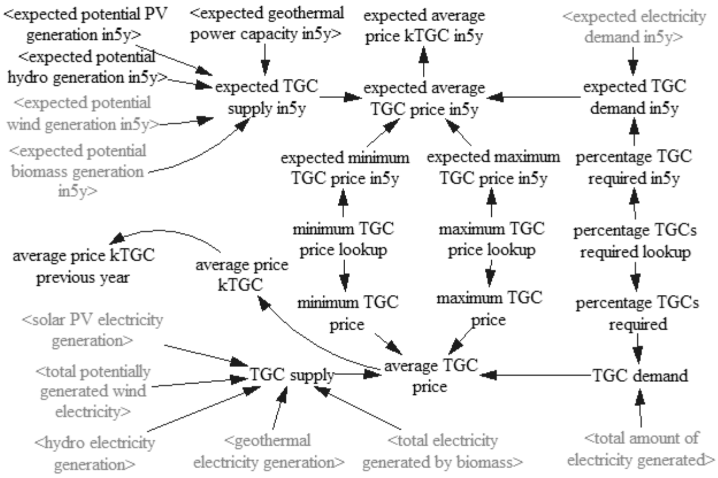

Figure 18: The emissions and schemes view of the stock/flow diagram

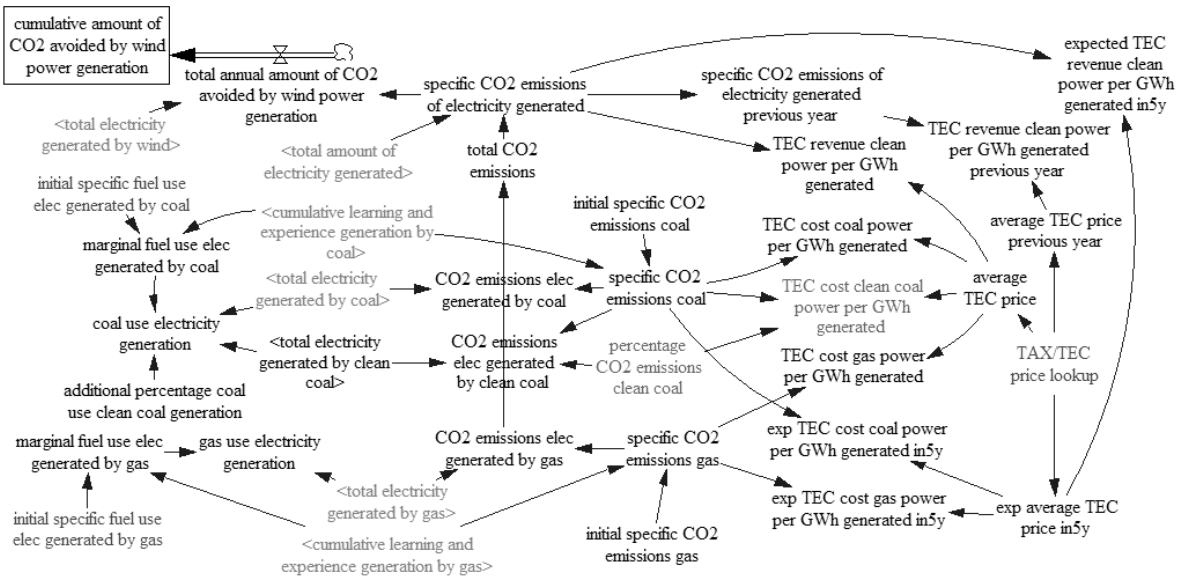

Figure 19: The CO_2 emissions and possible TEC and TAX schemes

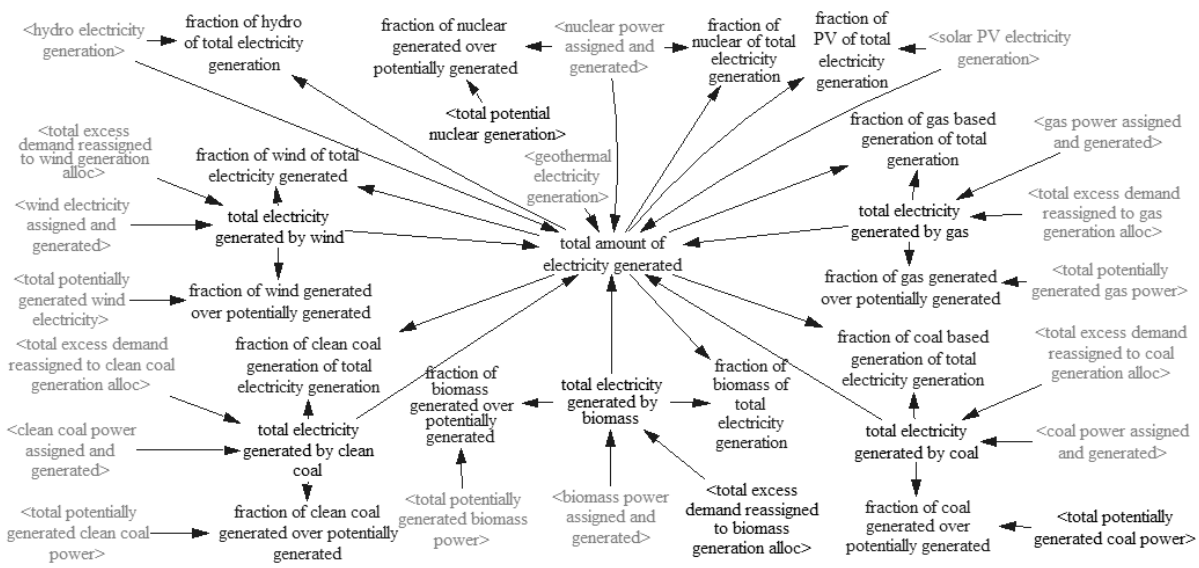

Figure 20: The *total amount of electricity generated* and the fractions of the different technologies

2.0.8 Amounts and Fractions Generated, and Monitoring and Control

The *total amount of electricity generated* and the fractions of the different technologies are calculated in the 'Amounts and Fractions Generated'-view displayed in figure 20.

And two additional views –the simulation control view and the simulation monitoring view (see figure 21)– facilitate the iterative exploration process.

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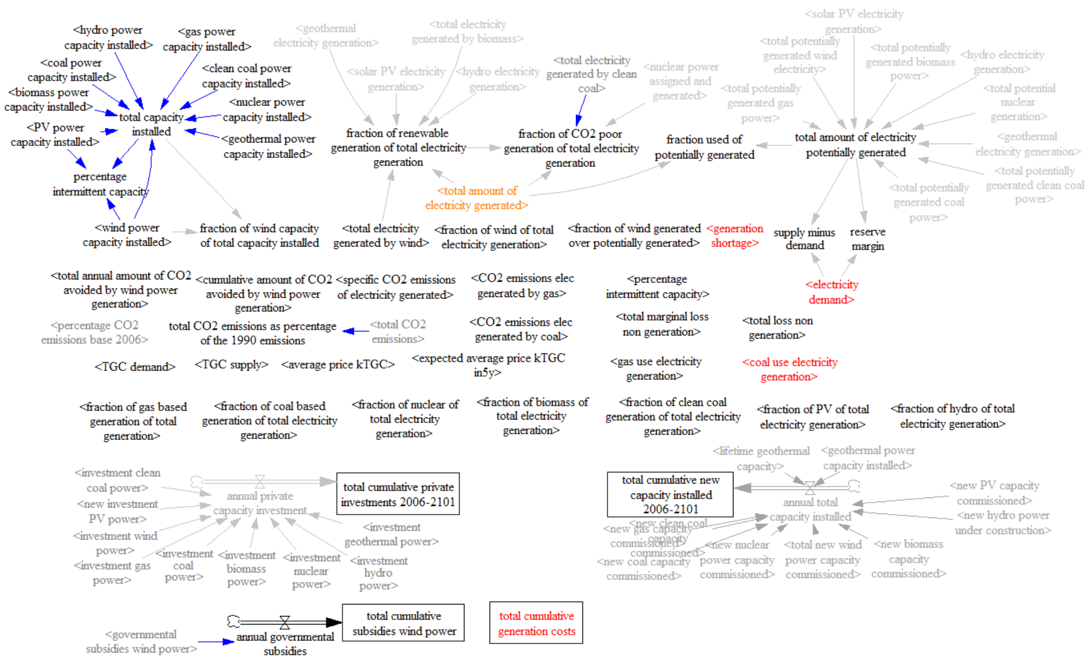

Figure 21: The simulation monitoring view