Dynamic Analysis of the Viability of Alternative Energy Sources in Meeting the Electricity Demand

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KEYWORDS

ABSTRACT

There are concerns that "traditional" energy sources (like coal and natural gas) may be inadequate in overcoming some challenges, such as pollution, costs and sustainability in the long term. Such traditional energy sources are either heavy polluters, environmentally unfriendly and/or are non-renewable by nature. So there is an increasing trend toward "alternative" and renewable energy sources such as biomass, solar and wind power. Many studies on future energy supply show that renewables will grow faster than any other method of electricity generation in the future But the viability of alternative and renewable energy sources in meeting the electricity demand in the long term has often been challenged. It has been argued that it is unrealistic and infeasible to meet a significant part of the electricity demand by alternative sources, because such sources are not only uncertain and inadequate, but they also exhibit high variability by nature. In this research we build a dynamic model in order to investigate if alternative energy sources can play a viable role in meeting the electricity demand in the long term. The model is constructed and calibrated using relevant energy and electricity data of Turkey. Different investment policies are investigated, based on cost considerations, on environmental indicators and other criteria. Results of different policy scenarios reveal the importance and viability of alternative energy sources under different conditions. We also investigate scenarios/policies that encourage energy savings.

INTRODUCTION

Long term energy planning faces several hard challenges, including pollution and other environmental concerns, costs (invetsments and operations) and long-term sustainability in meeting the increasing demand. There are concerns that the "traditional" energy sources (such as coal and natural gas) may be inadequate in overcoming these challenges in the long term. Such traditional energy sources are either heavy polluters, environmentally unfriendly and/or are non-renewable by nature. After the oil crisis of the 1970s, the importance of renewable energy for electricity generation

has increased so that they now provide nearly 20% of the world's primary energy requirement. The environmental benefits of power generation by renewables rather than combustion of fossil fuels have been the major driving force of this development. Particularly, in reducing the greenhouse and acid gas emissions associated with fossil fuel power generation, renewables are perceived to be a necessity. So there is an increasing trend toward "alternative" energy sources such as biomass, solar and wind power. Among the more traditional energy sources, there is increasing emphasis on "renewable" sources such as hydropower and geothermal. Many studies on future energy supply show that renewables will grow faster than any other method of electricity generation in the future (IEA, 2002a,b).

But the viability of alternative and renewable energy sources in meeting the electricity demand in the long term has often been challenged. It has been argued that it is unrealistic and infeasible to meet a significant part of the electricity demand by alternative sources, because such sources are not only uncertain and inadequate, but they also exhibit high variability by nature. (As electricity can not be acculumated, it requires effective and precise planning; it has to be generated just in time, parallel to the demand).

Dynamic systems modeling has been a noteworthy tool in the investigation of energy-economy interactions, conservation, environmental effects of energy planning policies, and the impact of privatization (Naill, 1973, 1992; Ford, 1983, 1985, 1997; Bunn and Larsen, 1992; Amlin and Backus, 1985, 1996). In this research we build a dynamic model in order to investigate if alternative energy sources can play a viable role in meeting the electricity demand in the long term. The model is constructed and calibrated using relevant energy and electricity data of Turkey. Turkey constitutes a major energy market and it is expected that a large gap will occur between energy consumption and demand in the future. (WEC TNC, 2000b). Our aim is to analyze electricity supply and demand conditions and to investigate the alternative ways of meeting Turkey's electricity need via renewable sources for medium and long terms. While seeking a balance in electricity supply and demand, CO_2 equivalent emission rates of the sources used in electricity generation process are considered as an indicator of environmental and ecological destruction in resource allocation policies.

THE MODEL

In the model, the emphasis is especially given to the allocation of future capacity need to renewable sources and non-renewable sources under different policies. The whole system involves the future electricity need as an exogenous input or a function of current consumption. The model is constructed and analyzed by using sector approach. The structure of the model is given in Figure 1 as a whole. There are nine sectors representing the sources selected for electricity generation process and three sectors for the calculations of current electricity demand, projected future demand and cost and emission accumulations. The sectors are grouped as renewables and non-renewables. Non-renewable ones include *Lignite Power Sector*, *Natural Gas Power Sector*, *Oil Power Sector* and *Hard Coal Power Sector*. Renewables include *Hydropower Sector*, *Wind Power Sector*, *Small-Scale Hydropower Sector*, *Geothermal Power Sector* and *Solar Power Sector*. The sectors included in the model are the ones that compose 97.2

per cent of the total capacity and generate 99.5 per cent of the total electricity generated as of 1998. (The LPG, Naphtha and Multi Fuel power plants are not included in the model). Therefore, analysis will be done for the determined sectors constituting most of the capacity. Within each sector, the allocated future capacity need is compared to the existing capacity and then construction is started if there is a capacity gap found by the calculation of expected capacity and the desired level of under construction capacity. The sectors diagram is illustrated in Figure 1.

The year 1990 is accepted as the base year. Since the available real data belonging to the electricity consumption and generation of Turkey are up to 1998, the validation of the major variables is done for eight years. The future electricity demand data available is up to 2010 and 2020. The model firstly will run for 25 years, from 1990 to 2015 for the medium term analysis, and the results will be examined. A long term, 55-year-simulation will also be done for a general analysis of the situation of the sources in the long term.
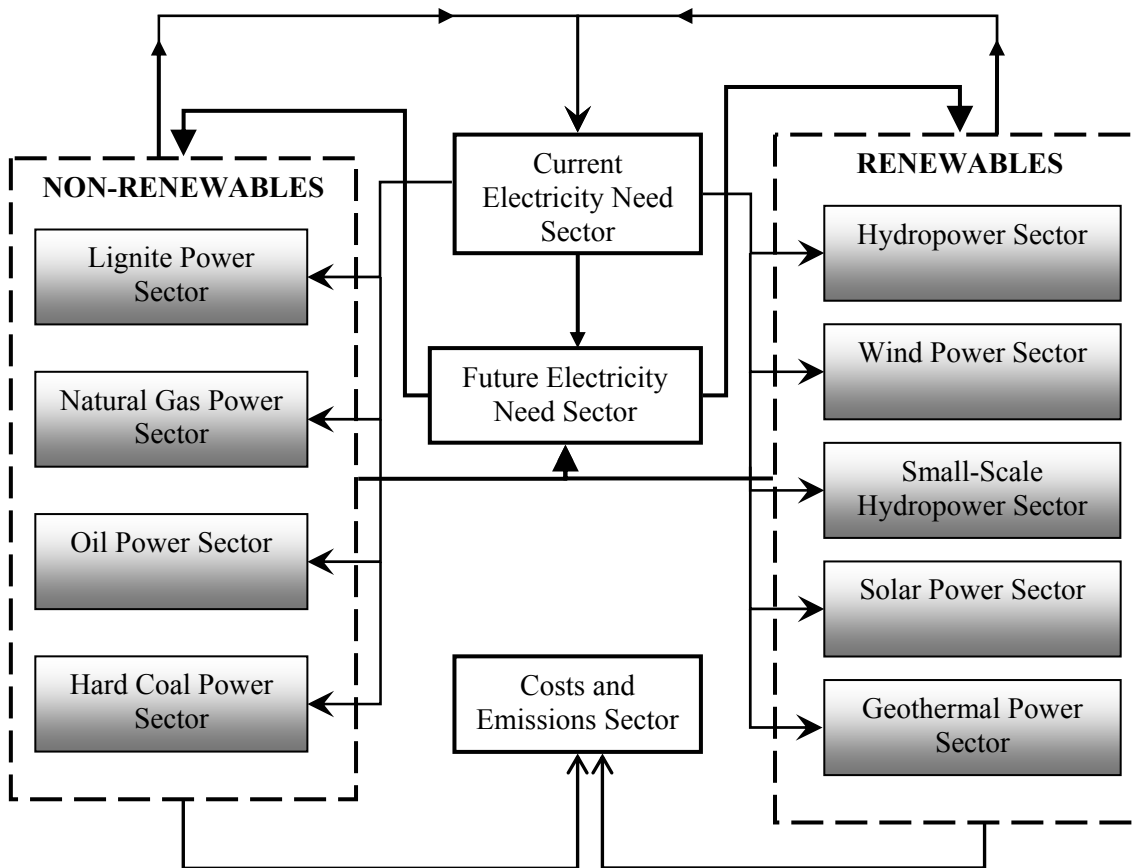

Figure 1. Sector Diagram

a) Current Electricity Need Sector

In *Current Electricity Need Sector*, the gross installed capacity is transformed to the net installed capacity by dropping the average internal consumption rate of the power plants. After subtracting the network losses, using the average ratio published by the government, the available net electricity generation capacity can be obtained. At the

same time, gross electricity consumption value is allocated to the sectors by considering their capacity ratios in the total after 1999. (Before 1999, the historical allocation coefficients which are generated by taking the average share of the related sector's electricity generation in the total electricity generated between 1990 and 1998 are used in meeting the current electricity need).

Essential variables of the sector are; Current Gross Electricity Consumption, Total Electricity Generation and Total Installed Capacity. (See the Appendix and Özdemir 2002 for more information). The actual historical gross electricity consumption and the future demand projection by the Ministry of Energy and National Resources (ETKB) (together with two alternative extrapolations used in the model) are shown in Figures 2 and 3.
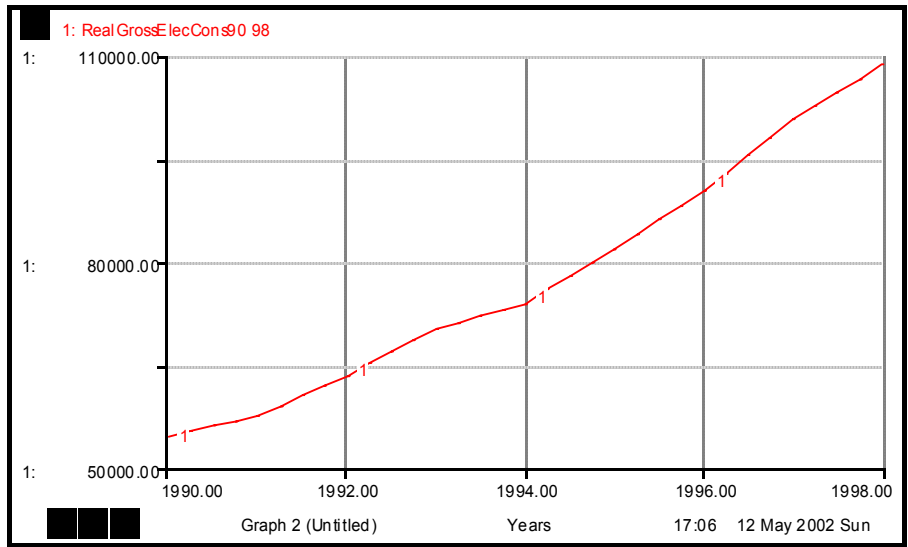
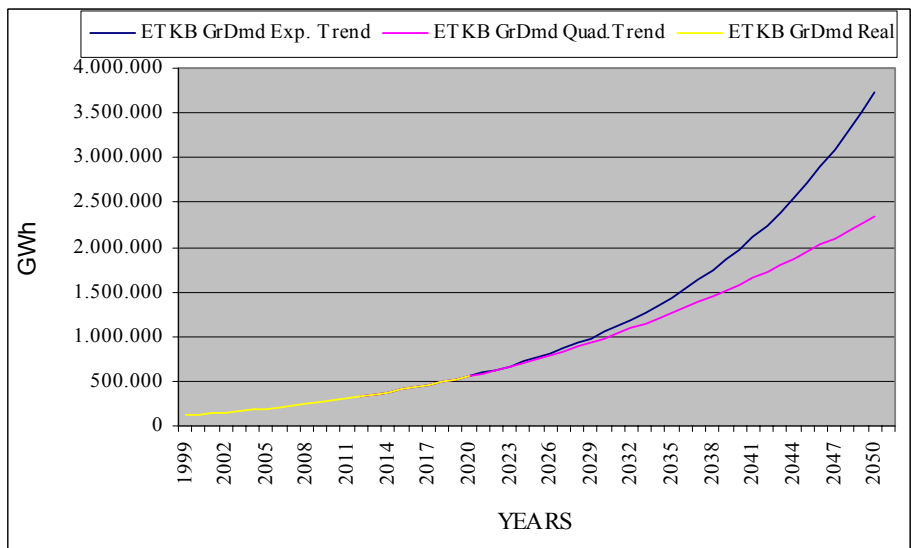Figure 2. Real Gross Electricity Consumption from 1990 to 1998 (GWh/year)
(WEC TNC, 2000a)

Figure 3. Extrapolated Gross Electricity Demand Forecast of ETKB, by Exponential and Quadratic Trends

b) Future Electricity Need Sector

Future Electricity Need Sector first involves the calculation of the future electricity need for five years into the future by using the current electricity consumption. This sector then allocates the future gross electricity generation demand in terms of GWh to the sectors of renewables and non-renewables by considering the remaining electricity generation potential of the renewables. Different allocation rules and parameters are used for non-renewable resources, which constitute different scenario runs.

The main variables in the sector are *Future Gross Electricity Consumption*, *Future Electricity Generation Demand*, *Total Potential of Renewables* (which is not used yet), *Requested Priority of the Renewables* and *Priority of the Non-Renewables*. (See the Appendix and Özdemir 2002 for more information).

c) Lignite Power Sector: A Representative of Non-Renewable Sources

In Lignite Power Sector, the processes of *gross electricity generation by Lignite Power Plants*, *lignite depletion from total lignite reserve, lignite import* and *capacity investments* are represented. Once new power capacity is invested, it undergoes a first order delay before it becomes operational. The installed capacity is then assumed to retire after a third order delay, representing average life of a typical plant. Figure 4 shows the stock-flow diagram of the sector.

Electricity generation is driven by the variable *CurLPNeedAllocGWh* that is the amount of electricity generation to be met by Lignite Sector. In calculation of this amount, an initial fraction is used in the historical period, 1990-1998, and then, for the new policy analysis, a smooth transition is done from the initial fraction to the new one which is the fraction of its electricity generation capacity in the sector total. Yearly electricity generation causes a decrease in lignite reserve. If yearly lignite production does not provide the required lignite amount then lignite is imported.

The variable *FutLPNeedAllocGWh* is the other driver of the sector. This variable represents the future electricity need allocated to lignite power sector. It is a portion of future non-renewable electricity need calculated in Future Need Sector. For 1990-1998, a historical installation fraction is used in this process. Then, for policy analysis, a smooth transition is done to a new installation fraction. In the scenario analysis, the installation fractions are based on the cost and emission release ratios of lignite power sector compared to other non-renewables. Finally, by comparing the expected capacity, under construction capacity against their desired (needed) values and considering the retired capacity, new capacity to be constructed is calculated according to the lignite power need, according to a stock adjustment heuristic.
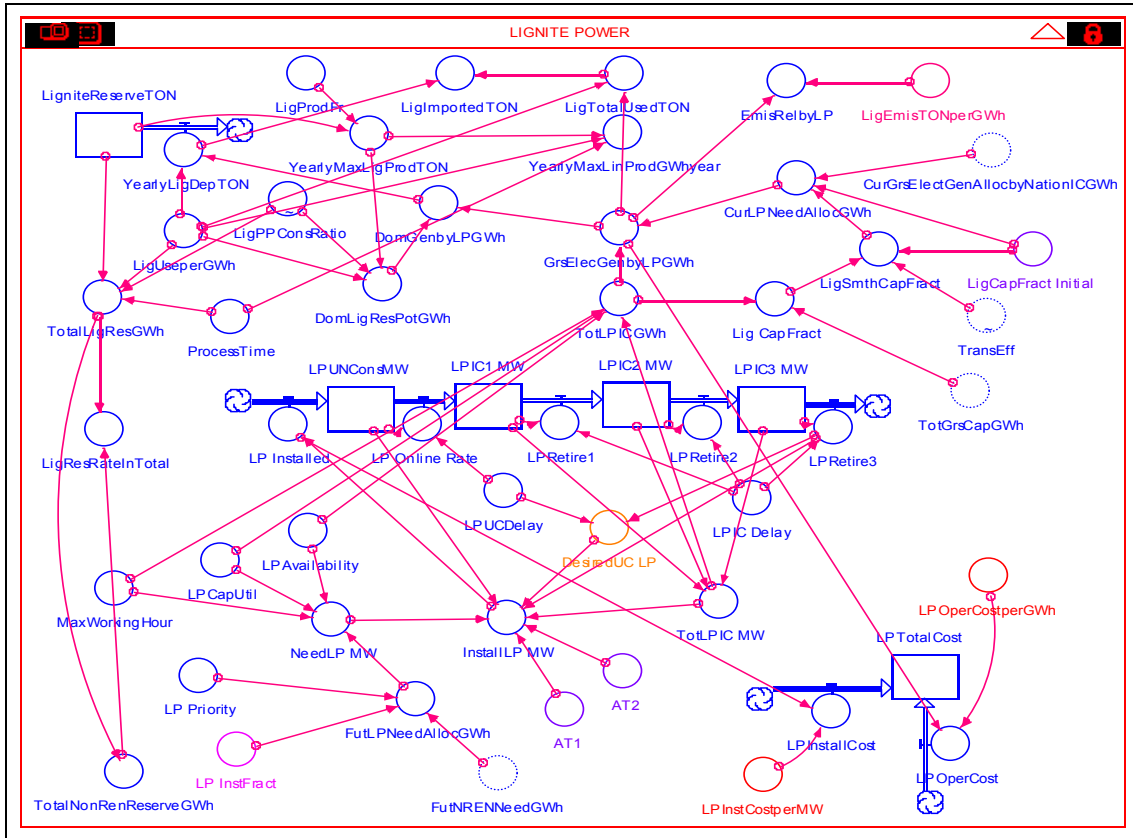
Figure 4. Lignite Power Sector

d) Hydropower Sector: A Representative of Renewables

The structure of Hydropower Sector is given in Figure 5. The starting point in the electricity generation process within the Hydropower Sector is the variable *GrsElectGenbyHPGWh*. The same logic of the non-renewable sectors described above is also valid for the renewable sectors in electricity generation step. However, an important difference is the structure of "electricity generation potential" of renewable sectors. There are maximum estimated levels of yearly gross electricity generation potentials for each renewable sector. The total of the installed capacity and under construction capacity is a part of total potential. Therefore, the potential of renewables is defined as *the potential not used yet*. The nature of the renewables allows to re-use of the potential through possible reinvestment, after the utility ends its useful life. So, the retired capacity flows in the stock *the potential not used yet.*

In the investment step of the sector, although the same structure with the non-renewable sector is used, there is a difference in the installation fractions. New installation fraction for hydropower is given by the ratio of hydropower sector's potential within the total potential of renewables not used yet. Through this approach, it is assumed that the dependence to a single source can be avoided.
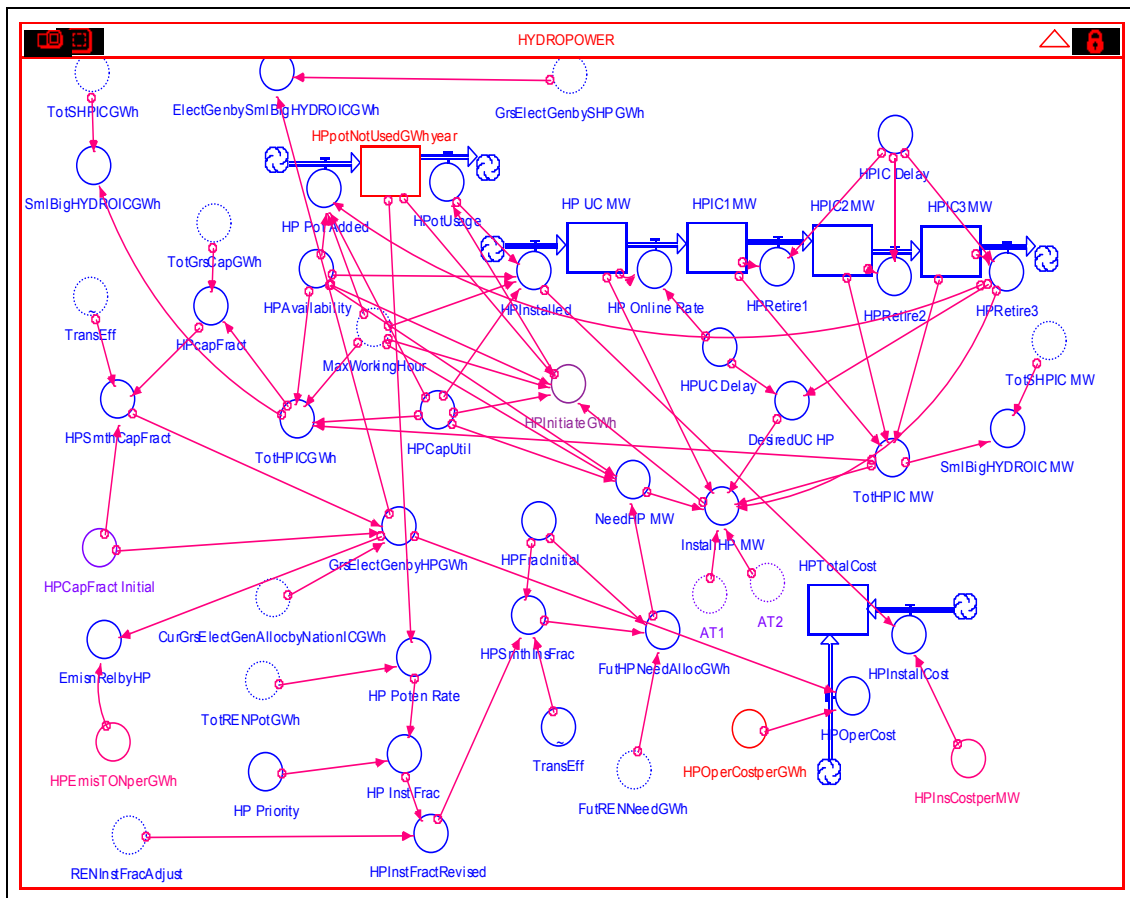
Figure 5. Hydropower Sector

VALIDATION

First, the structure of the model is tested by a range of structure tests, including dimensional consistency tests and extreme condition test. Results of these tests show that the model structure does not have any significant structural flaw. Due to space restrictions, these tests are not included in this paper. Instead, we illustrate some of the most informative behavior validity tests, done for period 1990-1998.

a) Total Installed Capacity and Electricity Generation Validation (1990-1998)

Figure 6 demonstrates the real installed capacity (Curve 2) of the years 1990 to 1998 and model-generated behavior (Curve1) in the same period. Although in the beginning years the model results and real data are close to each other, a little deviation is observed because of the initial fractions after the year 1994. On the other hand, the trend is similar so the model is accepted valid with respect to this behavior.
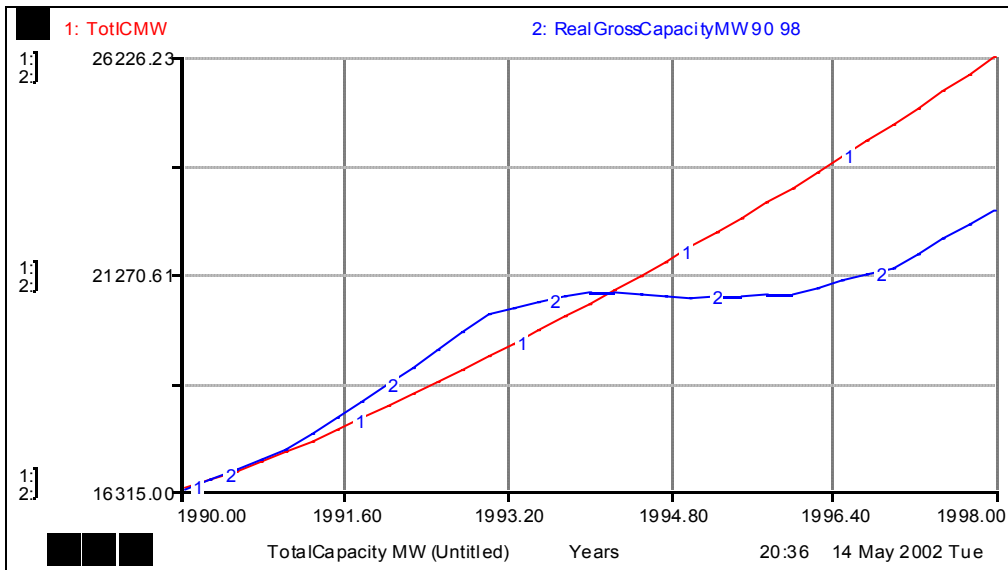
Figure 6. Total Installed Capacity Validation

On the electricity generation side, the real and model-generated behaviors are given in Figure 7. It is seen in the figure that both gross electricity generation (Curve 1) and net electricity generation (Curve 3) values obtained from the model are close enough to the historical data set (Curve 2 and Curve 4 respectively). It is obvious that they have the same growth patterns.
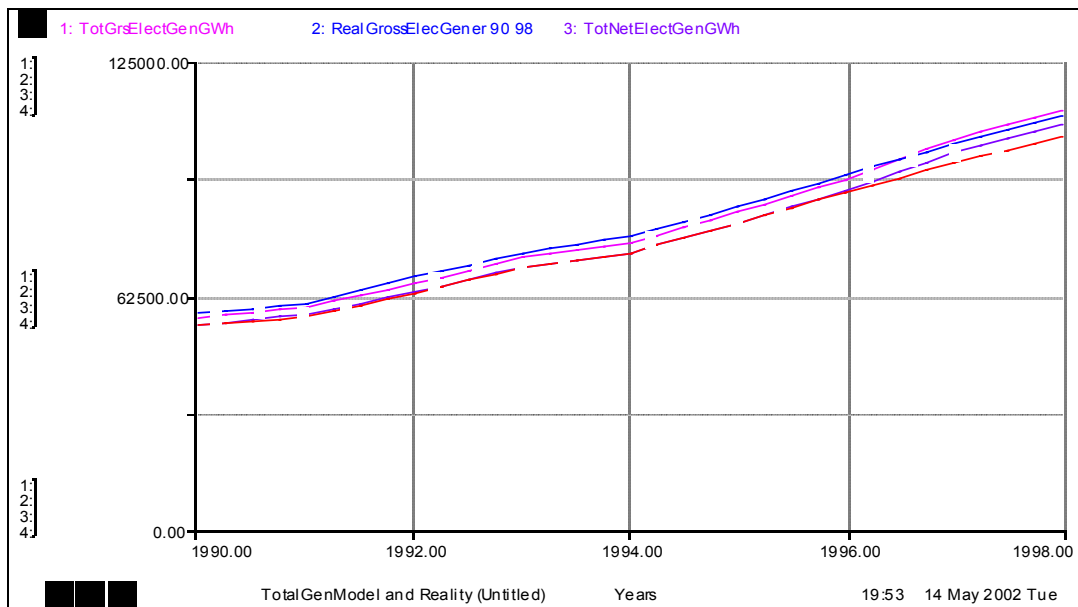

Figure 7. Total Electricity Generation Validation

b) Total Installed Capacity Validation for Non-Renewable and Renewable Sources (1990-1998)

Figure 8 presents the behaviors of total non-renewable and renewable sector capacities (MW). Model generated behavior for non-renewable sector (Curve 1) is

close to the real behavior (Curve 2). On the other hand, behavior of the renewable sector (Curve 3) shows valid pattern till 1993, after which model continues to invest in renewables at some given fraction of the total electricity need. But there is a sudden stop in the investments in renewables after 1993 in real life, which the model is unable to represent. Yet the electricity *generation* behaviors of both sectors do fit real data, as can be observed in Figure 9.
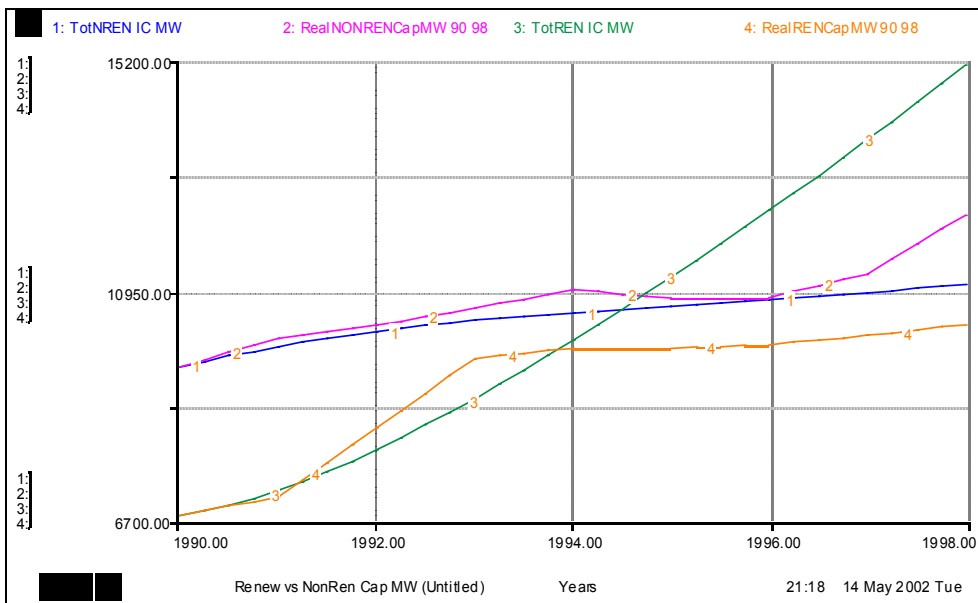

Figure 8. Total Installed Capacity Validation for Non-Renewable and Renewable Sectors
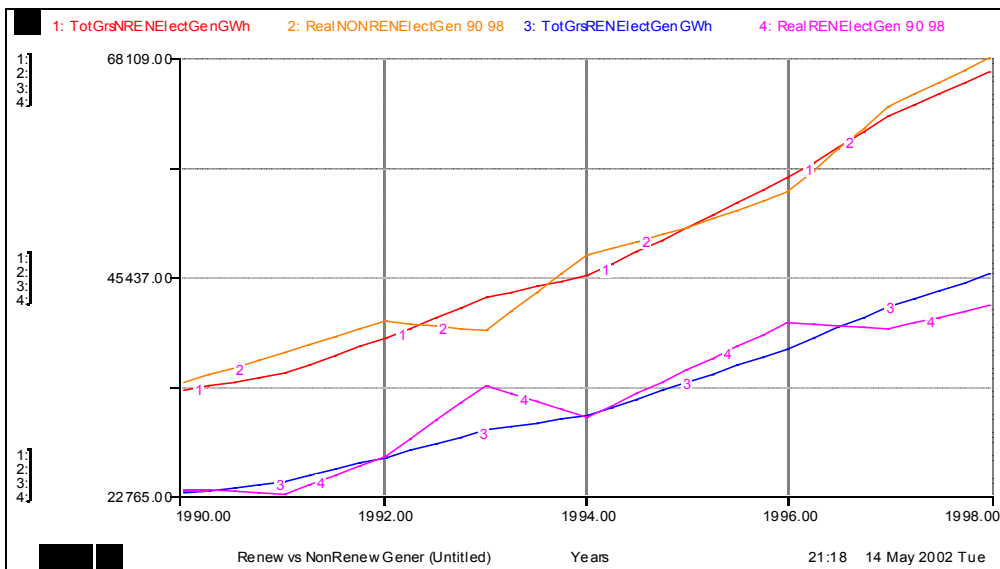
Figure 9. Total gross electricity generation validation for non-renewable and renewable sectors

- Lignite power, as a non-renewable sector validation illustration

Lignite Power Sector generates 30 per cent of total electricity in Turkey. So, the validation of lignite power sector is an important one. Model-generated and real lignite power installed capacities (Curve 1 and 2) and electricity generations (Curve 3 and 4) between 1990 and 1998 are shown in Figure 10. The amount of lignite used in electricity generation is given in Figure 11 together with the real data.
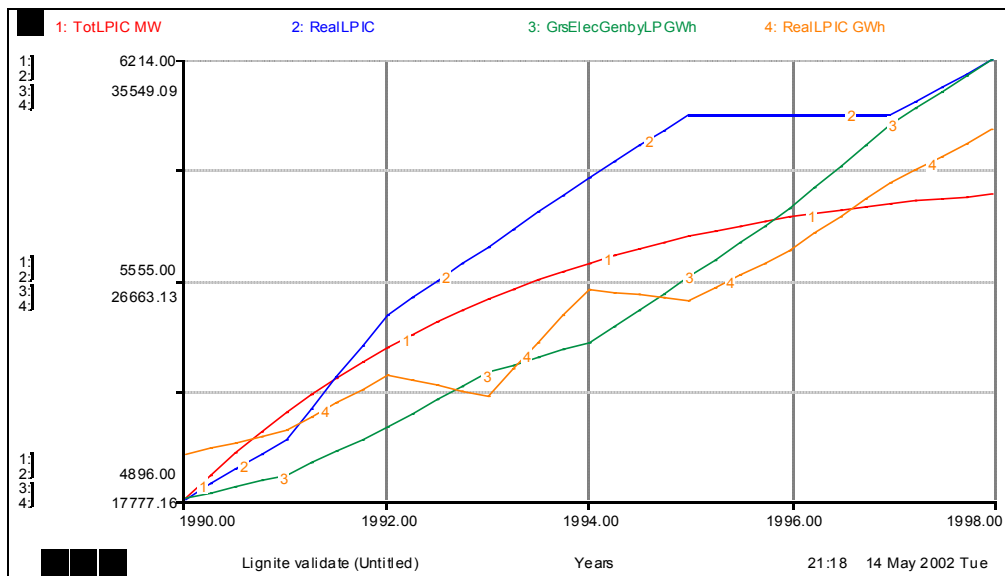
Figure 10. Total installed capacity and gross electricity generation validation for Lignite Power Sector
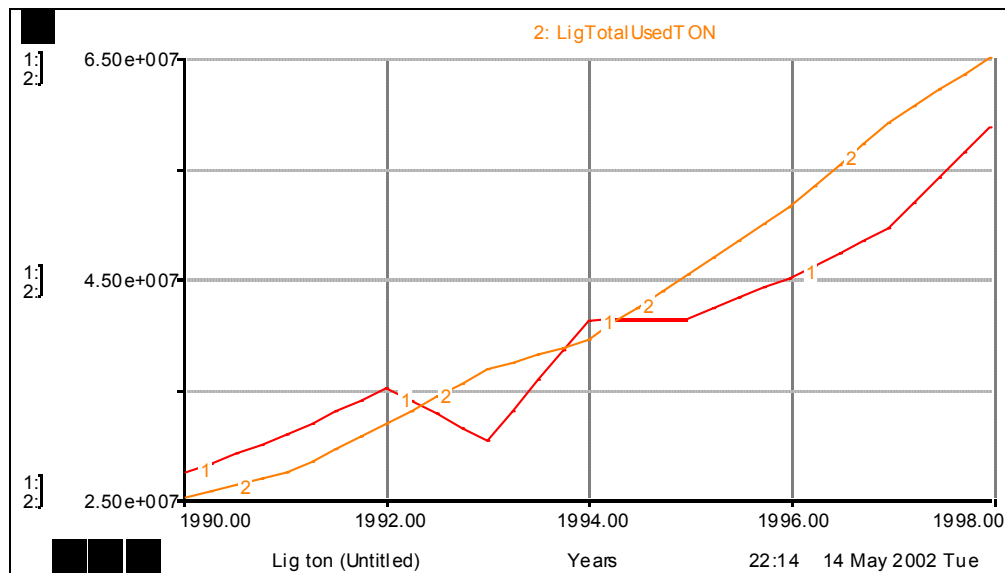
Figure 11. Validation of amount of lignite used in electricity generation (Ton)

Figures 10, 11 demonstrate that the main behaviors of the model variables are sufficiently close to the real data in the Lignite sector. Behavior validity of non-renewable resources is illustrated next.

- <u>Hydropower, as a renewable sector validation illustration</u>

Hydropower Sector constitutes approximately 40 per cent of total electricity generation in Turkey. Model-generated installed capacity and electricity generation behaviors are shown in Figure 12. The graphs demonstrate reasonably close fits to real data.
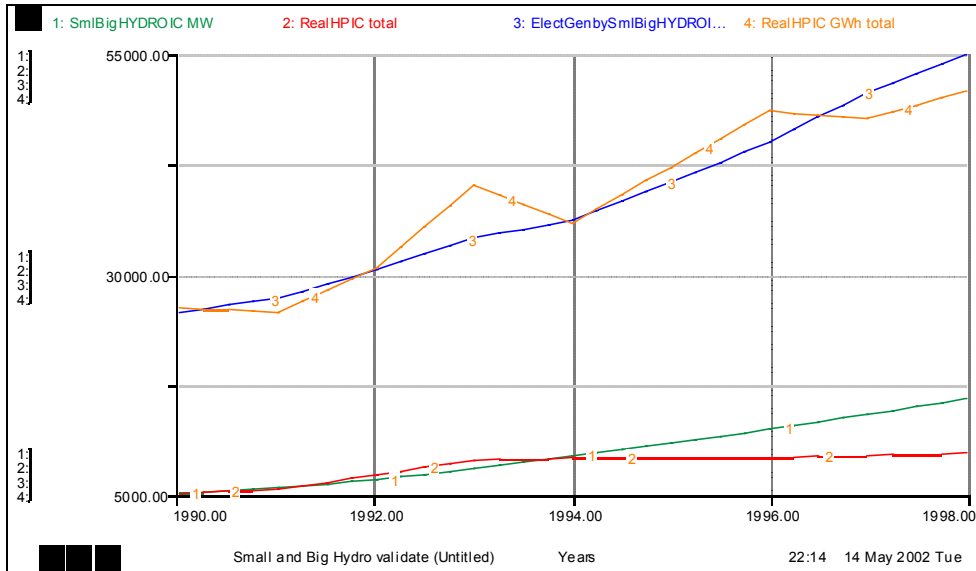

Figure 12. Total Installed Capacity and Gross Electricity Generation Validation for Hydropower Sector

SIMULATION EXPERIMENTS

Firstly, medium term simulations (from 1990 to 2015) and then long-term experiments (from 1990 to 2045) are done. In all simulations, DT is taken as 0.25.   In creation of the scenarios, a combination of some decision parameters listed in Table 1 are considered.

Table 1. Alternative scenarios for medium-term runs

Demand Forecast Scenarios		
RENEWABLE Weight	Within Renewables Installation Fractions	Within Non-Renewables Installation Fractions
Historical Priorities	Historical Inst. Fractions	Historical Inst. Fractions
0,5	Potential Based Fractions	Cost Based Inst. Fraction
0,5	Potential Based Fractions	Emission Based Inst. Fraction
0,5	Potential Based Fractions	Combined Cost&Emission Based Inst. Fraction
0	Potential Based Fractions	Cost Based Inst. Fraction
0	Potential Based Fractions	Emission Based Inst. Fraction
0	Potential Based Fractions	Combined Cost&Emission Based Inst. Fraction
1	Potential Based Fractions	Cost Based Inst. Fraction
1	Potential Based Fractions	Emission Based Inst. Fraction
1	Potential Based Fractions	Combined Cost&Emission Based Inst. Fraction

A gradual transition from historical policies to the new ones is captured by using a transition effect given in Figure 13. The values representing the historical policies are given in Table 2 and Table 3. These fractions are used in determining electricity

generation shares and capacity investment shares respectively. In various scenario/policy formulations, the investment fractions (variable) are formulated as:
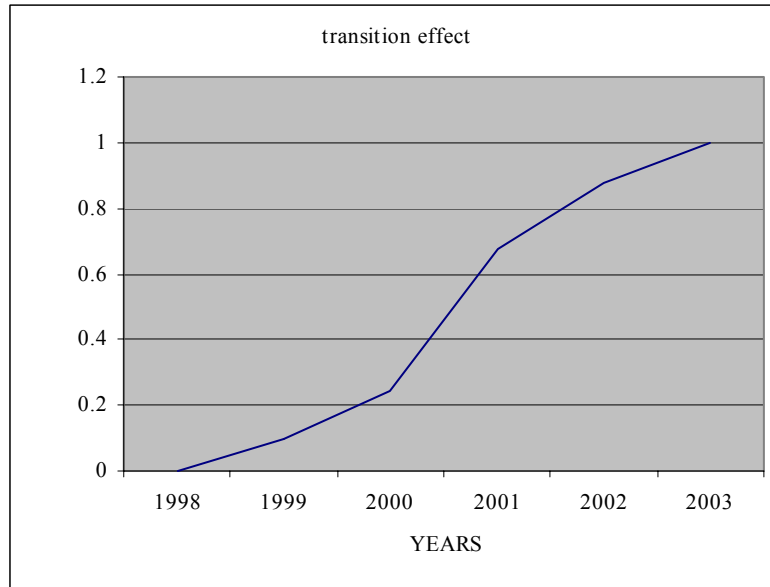(transition_effect)*(historical fraction)+(1-transition_effect)*(new fraction)

Figure 13. Policy Transition Effect

Table 2. Historical Electricity Generation Fractions of the Sectors

Lignite Power Plants	0.316	Hydropower Plants	0.393
Hard Coal Power Plants	0.024	Small Scale Hydropower Plants	0.011
Oil Power Plants	0.068	Geothermal Power Plants	0.001
Natural Gas Power Plants	0.187	Wind Power Plants	0
		Solar Power Plants	0

Table 3. Historical Capacity Investment Fractions of the Sectors

Lignite Power Plants	0.53	Hydropower Plants	0.971
Hard Coal Power Plants	0	Small Scale Hydropower Plants	0.027
Oil Power Plants	0	Geothermal Power Plants	0.002
Natural Gas Power Plants	0.47	Wind Power Plants	0
		Solar Power Plants	0

Medium Term Experiments:

a) Future Projections of Historical Policies:

If historical policies are continued, then the behaviors of total and installed capacities of renewable and nonrenewable sectors are presented in Figure 14.
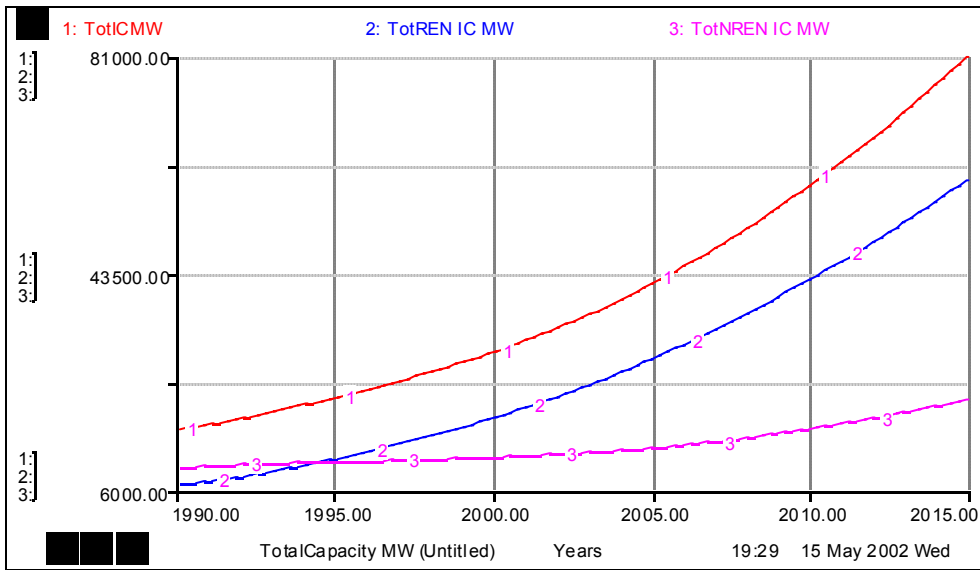
Figure 14. Total Installed Capacity (MW)

In Figure 15, it is observed that electricity import starts after 1998. The import reaches a value of 98,667.19 GWh/year in 2015. It is apparent that the total gross capacity (Curve 1) is not completely used in (Curve 2) to meet the demand (curve 3). Since the historical fraction is taken as constant, electricity generations are not affected by the generation capacities of the sectors, current electricity generation allocation to the sectors via the historical data is not robust after year 1998. Although total gross capacity is higher than the demand till year 2007, the electricity generation is smaller than the demand. This situation shows the problem with continuing the historical allocation fractions.
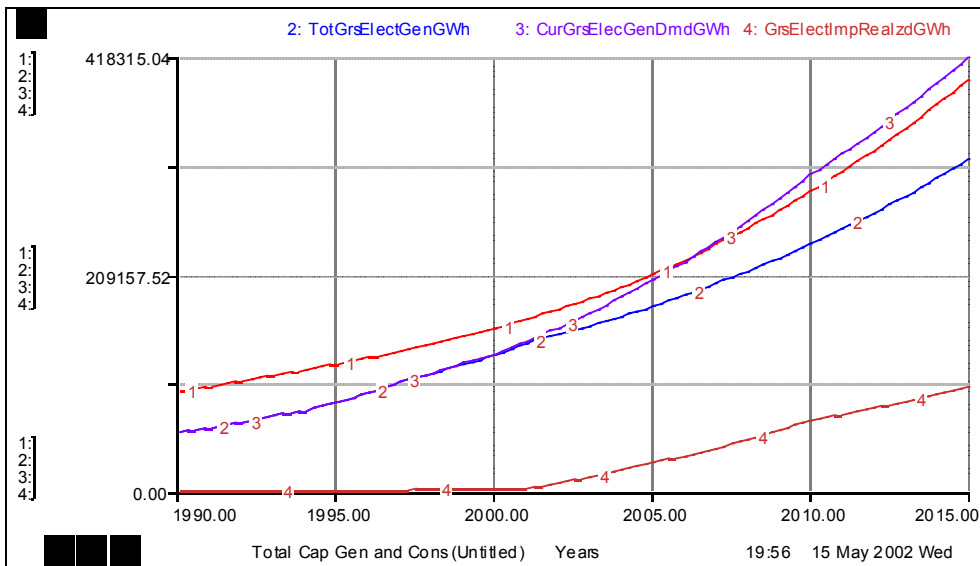

Figure 15. Gross Electricity Capacity, Generation, Demand and Import (GWh)
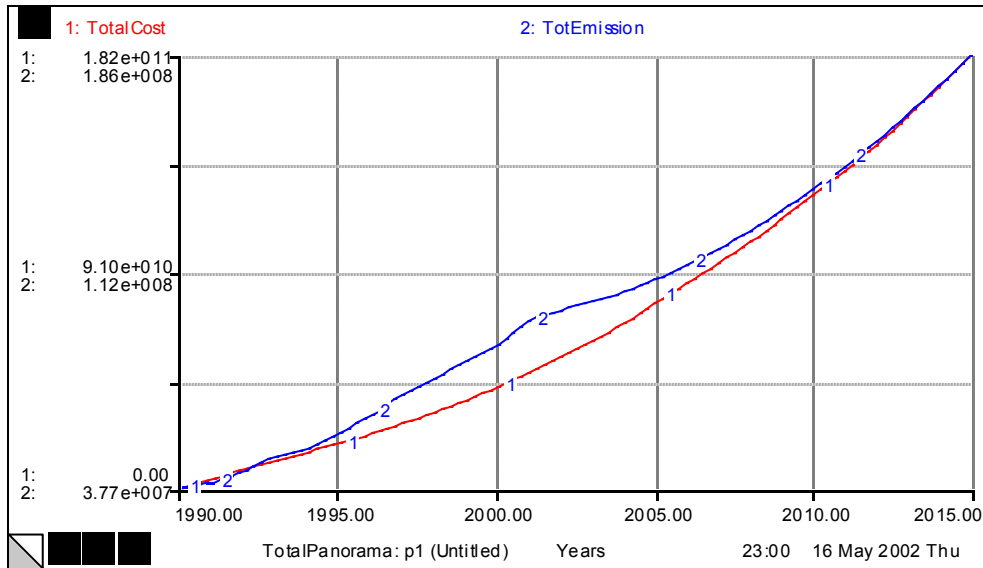
Figure 16. Total Cost and Emission (USD and Ton)

b) Renewable/Non-Renewable Equally Weighted Policy (0.5 Each)

- Cost based non-renewable installation fractions.

The cost fractions used as installation fractions in non-renewable sectors are computed as follows.

Lignite Power Installation Fraction: 19%
Hard Coal Power Installation Fraction: 21%
Oil Power Installation Fraction: 15%
Natural Gas Power Installation Fraction: 45%

Each fraction determines the electricity amount of individual non-renewable resources according to their relative costs.

This scenario gives priority to renewables 50 per cent, the same as non-renewables after year 1999. The future gross need is allocated according to the priority levels of sectors. Then, within each sector group (i.e. renewables and non-renewables), the allocated future need is allocated to the sectors involved in the group. Within this frame, the electricity generation results of the simulation can be observed as in Figure 17 and Figure 18. In Figure 17, Curve 1 shows that a huge investment has been made to the renewable sectors, so the capacity has increases sharply and reaches 128,091.89 MW in 2015. It is also important that the renewable power plants work with a low availability. In order to generate the same amount of electricity, renewable sectors generally require higher capacity than the non-renewable ones. It is also seen that there is not any considerable electricity import.
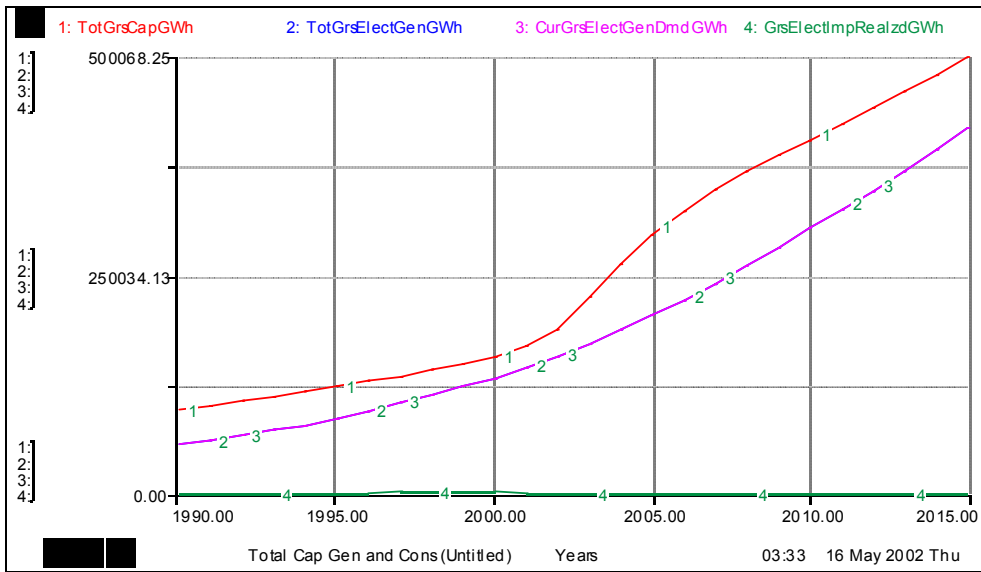
Figure 17. Gross Electricity Capacity, Generation, Demand and Import (GWh)

It is seen in Figure 18 that total cost is rather higher than the result of reference model (see Figure 16). Its value is almost four times of the reference runs value. Total emission released at 2015 is approximately 13 per cent higher than the reference run emission level at the same year.
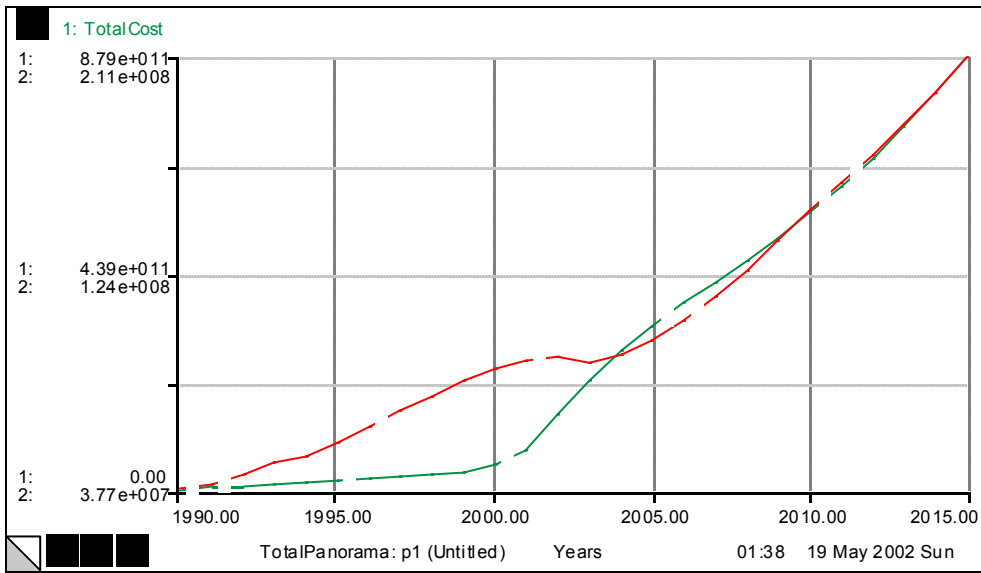

Figure 18. Total Cost and Emission (USD and Ton)

- Emission based installation fractions.

Emission based fractions are computed for the non-renewable sectors and assigned as follows:

Lignite Power Installation Fraction: 21%
Hard Coal Power Installation Fraction: 21%
Oil Power Installation Fraction: 29%
Natural Gas Power Installation Fraction: 29%

Each fraction determines the electricity amount of individual non-renewable resources according to their relative emission levels.

The system behavior in electricity generation process is the same as the previous runs. Briefly, a capacity excess is observed after 2002. The important result through this policy is obtaining low emission levels. In Figure 19, Curve 5 depicts the yearly released emission levels. For comparison of non-renewable and renewable electricity generation capacities, observe Curve 2 and Curve 3.
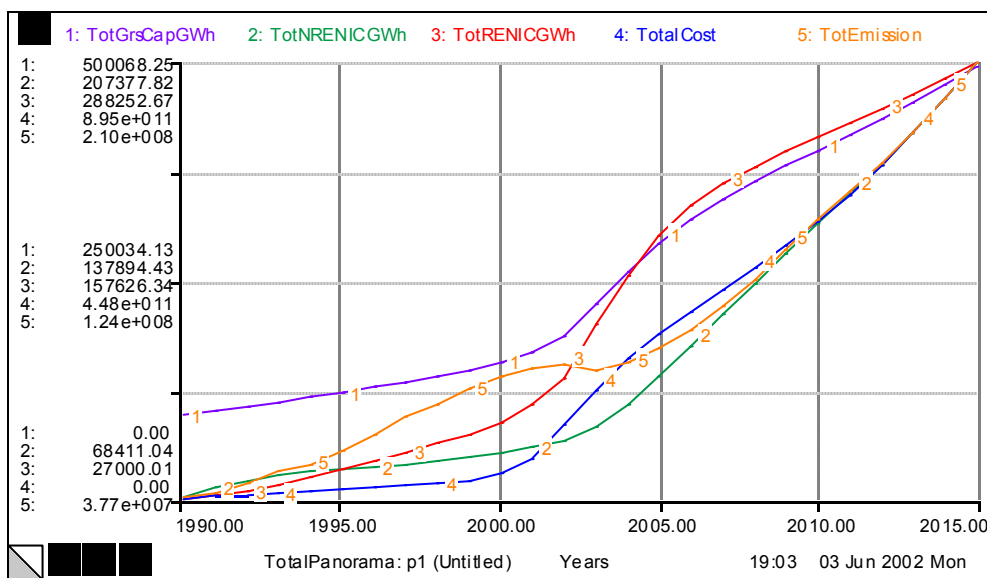

Figure 19. Total Gross Capacity, Non-renewable and Renewable Capacity (GWh), Cost and Emission (USD and Ton)

- Combined cost & emission based fractions

Combined cost and emission based fractions are computed for the non-renewable sectors and assigned as follows:

Table 4. Combined Cost and Emission Based Installation Fractions

NON-RENEWABLES	INSTALLATION COST FRACTIONS	OPERATION COST FRACTIONS	EMISSION FRACTIONS		COMBINED FRACTIONS
	%	%	%	product	%
Lignite Power Plants	0,19	0,34	0,21	0,01357	0,20
Natural Gas Power Plants	0,45	0,28	0,29	0,03654	0,55
Oil Power Plants	0,15	0,14	0,29	0,00609	0,09
Coal Power Plants	0,21	0,24	0,21	0,01058	0,16
TOTAL				0,06678	1,00

Each fraction determines the electricity amount of individual non-renewable resources according to their relative "combined cost and emission" levels.

This scenario does not yield electricity import since the capacity is too high compared to reference behavior. Total emission released, shown in Figure 20, is a little higher then reference behavior result. The levels of the fuel imports are also depicted in Figure 21 for this scenario.
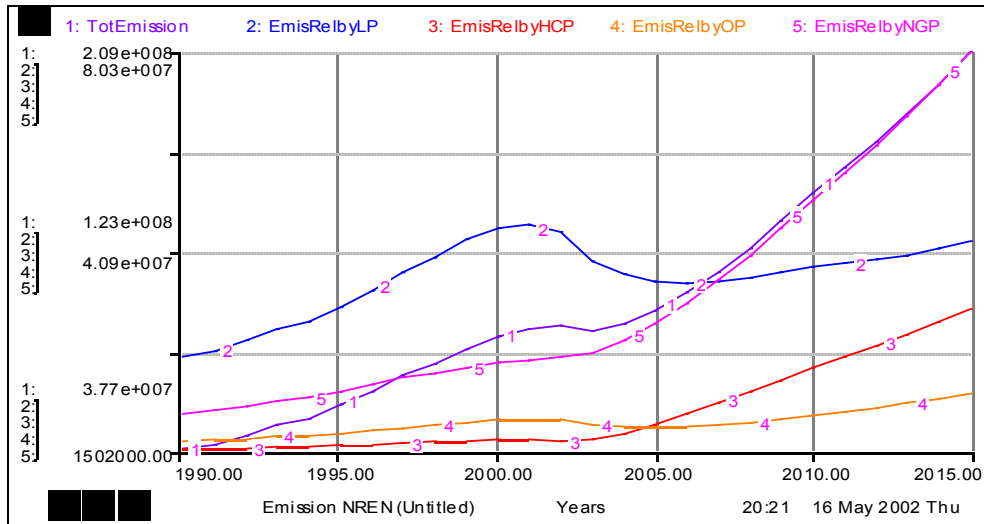

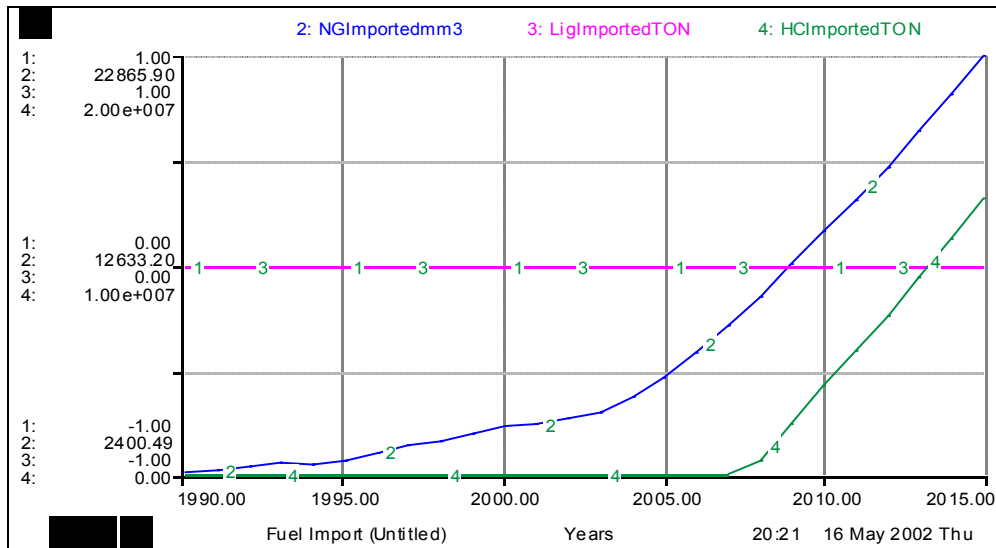Figure 20. Emission Levels of Whole System and Non-Renewable Sectors

Figure 21. Fuel Imports

c) Renewable Oriented Policy

- Combined cost & emission based fractions.

Figure 22 demonstrates that renewable oriented capacity investments create capacity excess and energy need can be entirely met. Total cost and emission levels are given in Figure 23. It is seen in Figures 22 and 23 that the total costs reach very high levels whereas the emission levels are quite low compared to other policies.
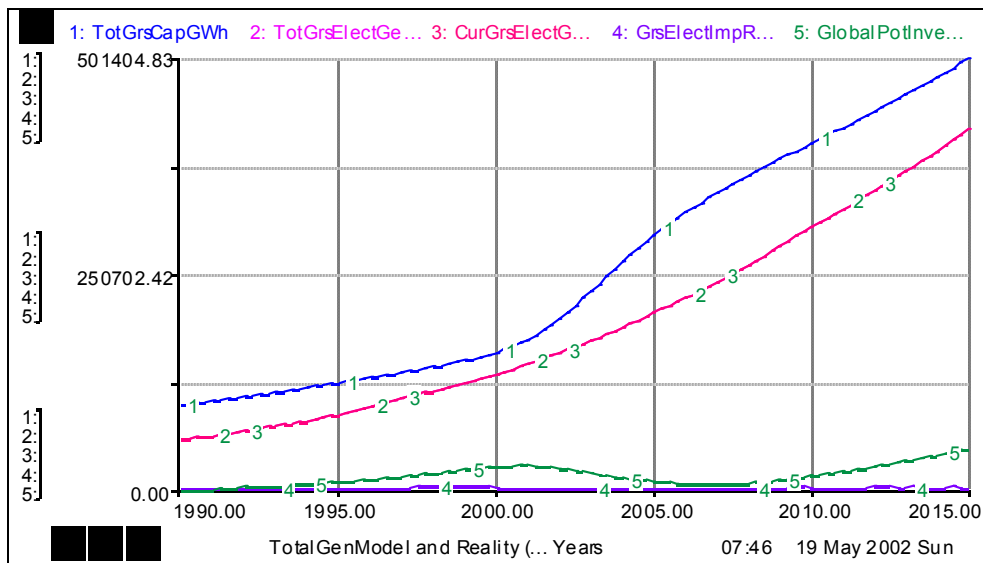

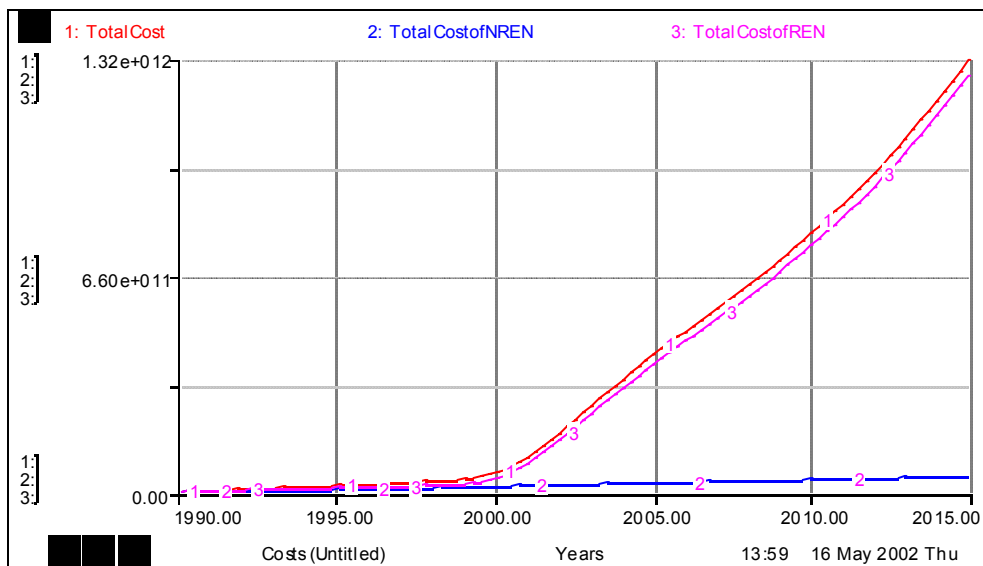Figure 22. Total Electricity Capacity, Generation, Demand and Imports (GWh)

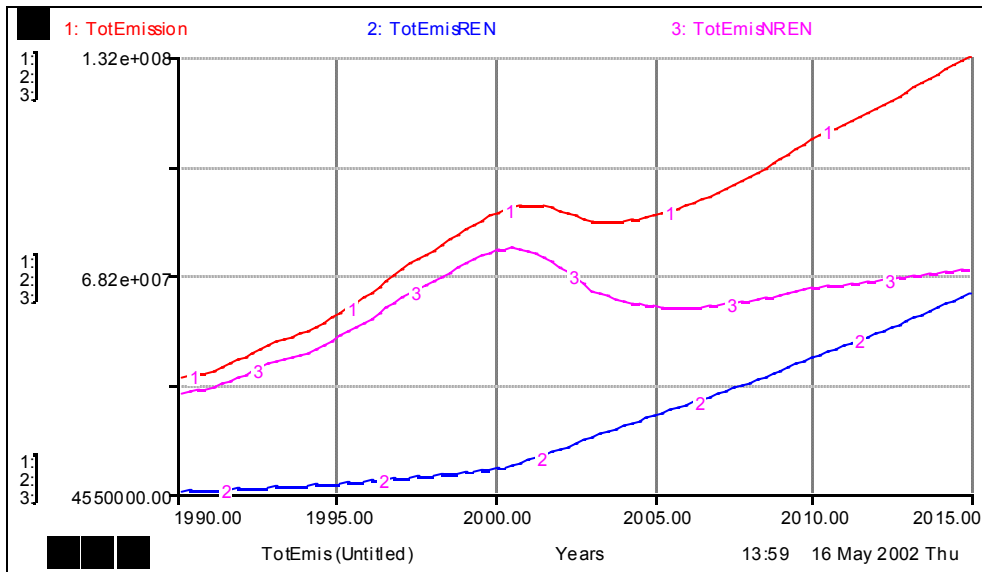Figure 23. Cost levels of whole system and sector groups

Figure 24. Emission Levels of Whole System and Sector Groups

d) Non-Renewable Oriented Policy

- Combined cost & emission based fractions.

Figure 25 shows that total gross electricity demand is met by capacity till 2013 with an excess capacity. Afterwards, all installed capacities are completely used in meeting the need. Through this policy, it is seen in Figures 26 and 27 that while total cost at the end of simulation is lower than the result of renewable-oriented policy, the emission level released is quite higher. The levels of fuel imports are illustrated in Figure 27. The trend in import of natural gas is increasing with this policy while oil import becomes stable for a while and again begins to increase.
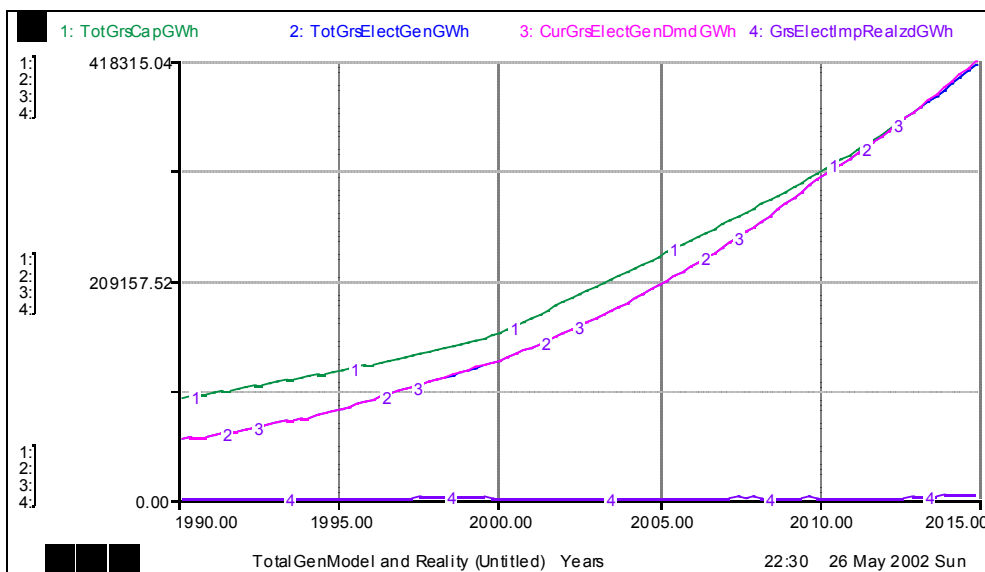

Figure 25. Total electricity capacity, generation, demand, and total cost and emission
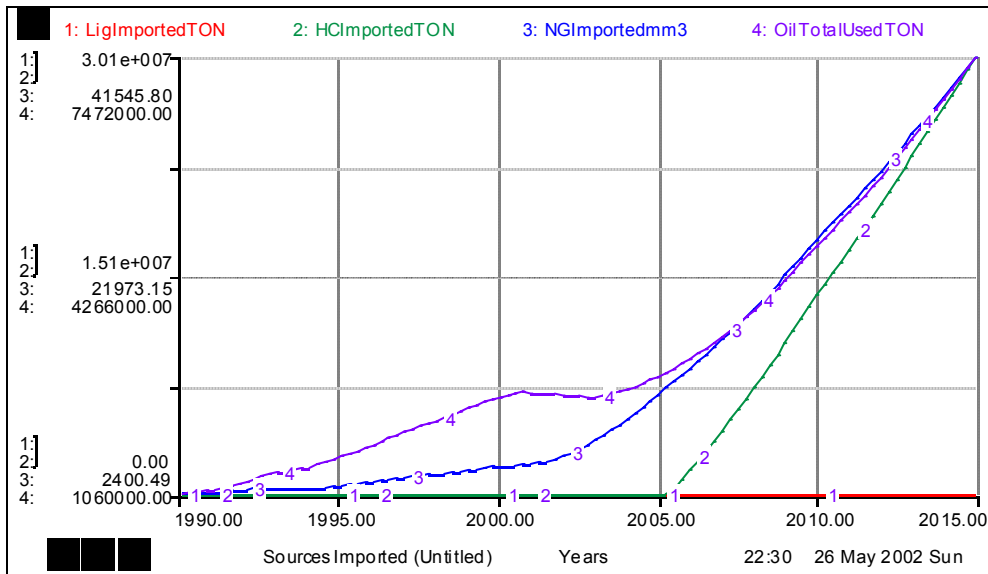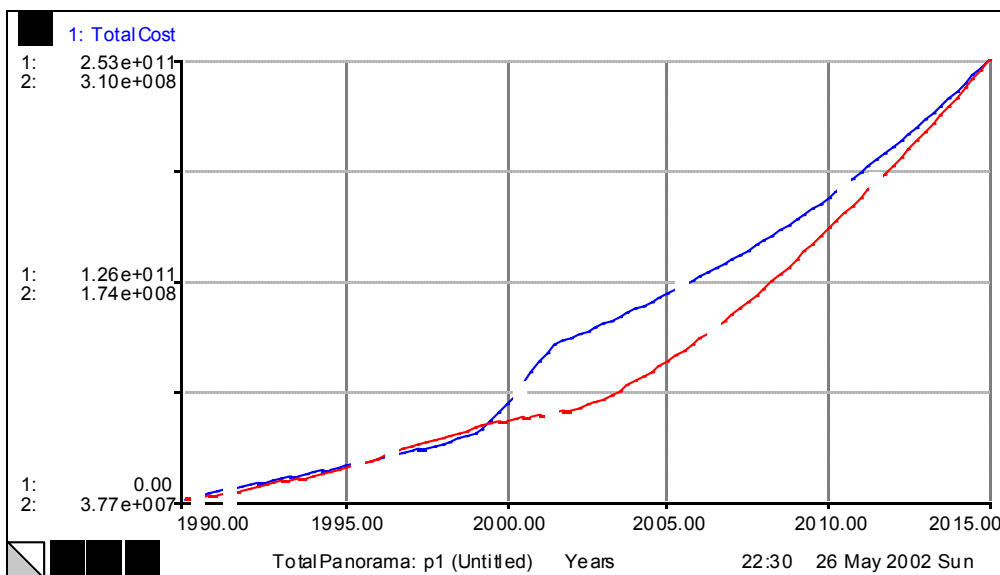
Figure 26. Fuel imports

Figure 27. Cost levels of whole system and sector groups

Table 5 gives the comparative values of major variables for all runs done for medium term analysis. To summarize, at the end of simulation, in year 2015, it is observed that gross electricity demand can be satisfied by total install capacity with negligible electricity imports for all policies. But, there are capacity excesses occurring with renewable/non-renewable equally weighted policy, renewable oriented policy and historical policy. In Table 5, it is observed that the minimum level of accumulated emission can be obtained by renewable oriented policy emission based non-renewable installation. Furthermore, non-renewable oriented policy with combined cost and emission non-renewable installation policy gives the minimum level of accumulated cost as at 2015. But note that in non-renewable oriented policies there are significant fuel imports (as seen already in the figures discussed) not included in the above cost figures, implying that these latter underestimate the total costs of non-renewable

policies. Also note that "electricity import" is shown as a separate variable in the table, and its cost is not included in the accumulated cost entry. Therefore, accumulative costs in the base run significantly underestimate the actual total cost in cases where there are electricity imports (i.e. BASE RUN).

Long- Term Experiments:

Conservation Scenario:

In the conservation scenario, the first assumption is based on consumption efficiency. Electricity saving by all consumers will be promoted via different methods and a 10 per cent saving is assumed to be realized in total. For this purpose a *"savings effect"* has been developed and presented in Figure 28. There are two curves; *current savings effect* and *future savings effect*. It is assumed that current savings effect plays its role on current consumption after the year 2000. Its value reaches 10 per cent in 2015. 15 year-delay to have a stable savings ratio is assumed to be an acceptable delay since the social attitudes may not change so easily. In this project, it is assumed that a 10 per cent saving can be realized in 15 years, from 2000 to 2015. When calculating the future investments, savings effect has to be estimated. Therefore, current savings effect is transformed to future savings effect by shifting the beginning year to five year earlier. For instance, in computing the future electricity generation demand the value of current savings effect as of 2000 will be taken into account in 1995.
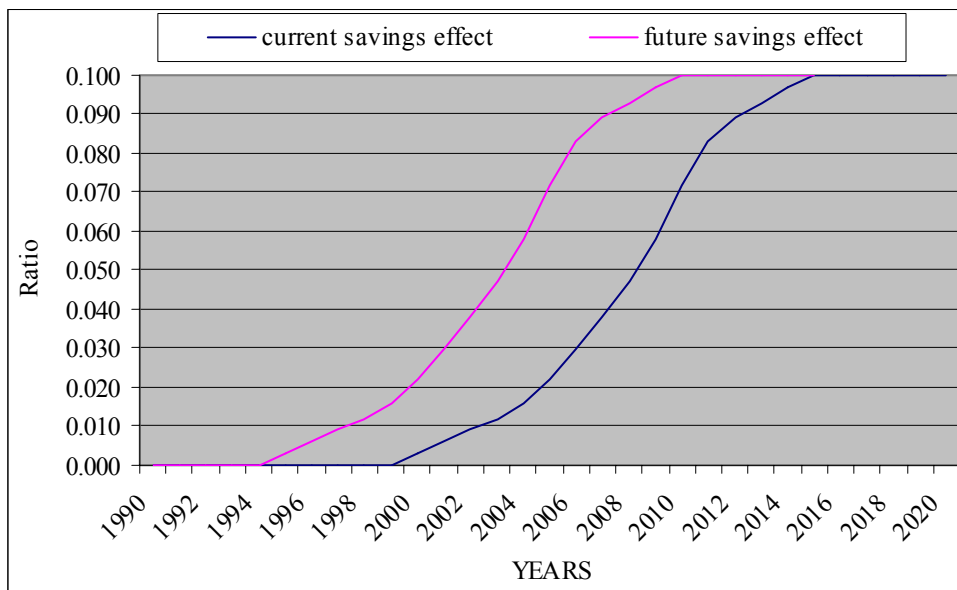

Figure 28. Current and Future Savings Effect

The second aspect of the conservation policies is about the network losses. It is assumed that network losses can be reduced down to 10 per cent from 18 per cent in ten years. Figure 29 demonstrates the assumed change in network losses. The change begins in 2000 and ends in 2010, and then the network losses ratio stays stable at 10 per cent. 10 year-delay is assumed sufficient to improve the network. Note that the variable network losses is used in the calculation of total available net electricity generation capacity, total domestic net electricity consumption and current electricity consumption.

Table 5. Comparative values of main variables at year 2015 for different policies

|	Historical Policy Continued (BASE RUN)	Renewable and Non-Renewable Equally Weighted Policy	Renewable Oriented Policy	Non-Renewable Oriented Policy
Yearly Gross Electricity Demand (GWh)	418,315	418,315	418,315	418,315
Yearly Total Gross Capacity (GWh)	396,388			
Cost Based Non-Renewable Installation		499,544	501,404	412,711
Emission Based Non-Renewable Installation		495,285	501,351	408,168
Cost&Emission Based Non-Renewable Installation		499,944	501,418	414,901
Yearly Gross Electricity Generation (GWh)	319,647			
Cost Based Non-Renewable Installation		418,315	418,315	412,711
Emission Based Non-Renewable Installation		418,315	418,315	408,168
Cost&Emission Based Non-Renewable Installation		418,315	418,315	414,901
Capacity Utilization (%)	81			
Cost Based Non-Renewable Installation		84	83	100
Emission Based Non-Renewable Installation		84	83	100
Cost&Emission Based Non-Renewable Installation		84	83	100
Accumulated Electricity Import (GWh)	676,578			
Cost Based Non-Renewable Installation		968	1,001	9,279
Emission Based Non-Renewable Installation		978	1,013	28,661
Cost&Emission Based Non-Renewable Installation		966	996	4,411
Accumulated Emission (TON)	2,494,745,945			
Cost Based Non-Renewable Installation		2,530,792,503	2,077,950,814	3,148,299,523
Emission Based Non-Renewable Installation		2,518,259,709	2,076,055,485	3,131,547,098
Cost&Emission Based Non-Renewable Installation		2,518,857,427	2,078,248,515	3,132,302,283
Accumulated Cost (USD)	181,998,202,073			
Cost Based Non-Renewable Installation		903,577,816,723	1,319,034,250,869	264,914,478,716
Emission Based Non-Renewable Installation		920,722,722,471	1,320,243,730,763	288,889,548,266
Cost&Emission Based Non-Renewable Installation		895,648,108,291	1,318,435,346,773	252,628,869,496
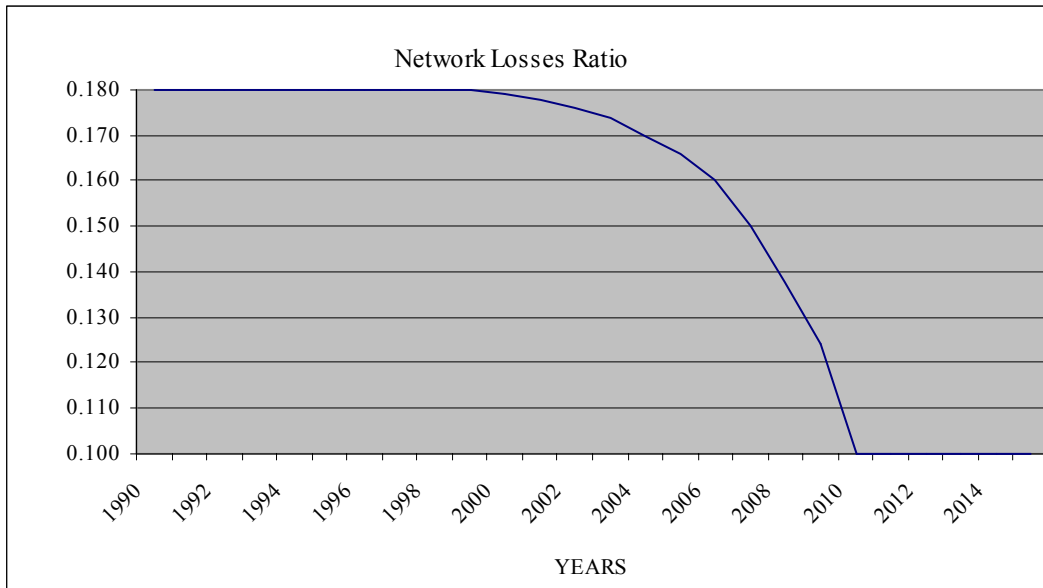
Figure 29. Network Losses Effect

- Future projections of historical policies with savings

The reference model behaviors are examined by long term simulation. The existing policies yield a growing electricity import (curve 4) even though conservation policies are applied after 1999. In 2045, the gross electricity import becomes 689,040.34 GWh which is 27 per cent of the gross electricity demand. Total cost and emission levels are illustrated in Figure 31.
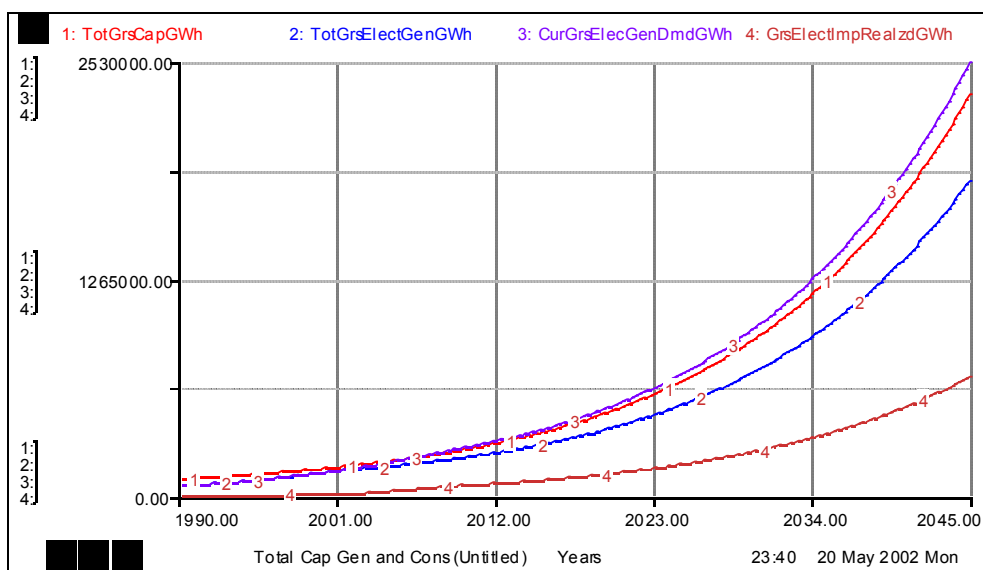

Figure 30. Total Electricity Capacity, Generation, Demand and Import (GWh) with Savings (Historical policies continued)
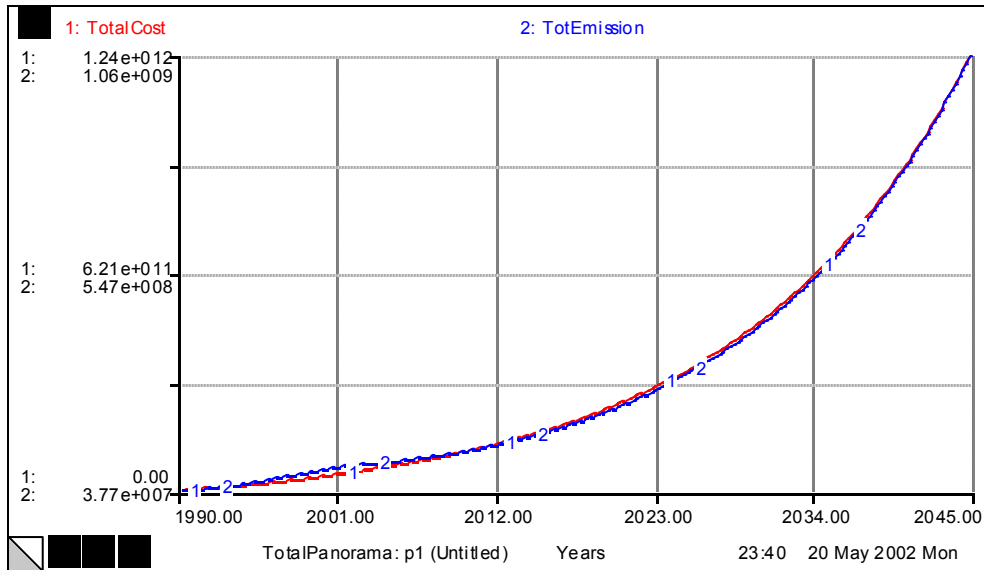
Figure 31. Total Cost and Emission with Savings (Historical policies continued)

Figure 32 shows the historical policy results without savings for long term simulation. It is observed that 765,890.71 GWh electricity import occurs if existing policy continued. Note that, total cost and emission levels reach 1.37×10^{12} USD and 1.17×10^{9} Tons respectively. Consequently, the conservation scenario under historical policy yields 90 per cent reduction in total cost level, emission level and electricity import respectively, compared to historical policy without savings as of 2045.
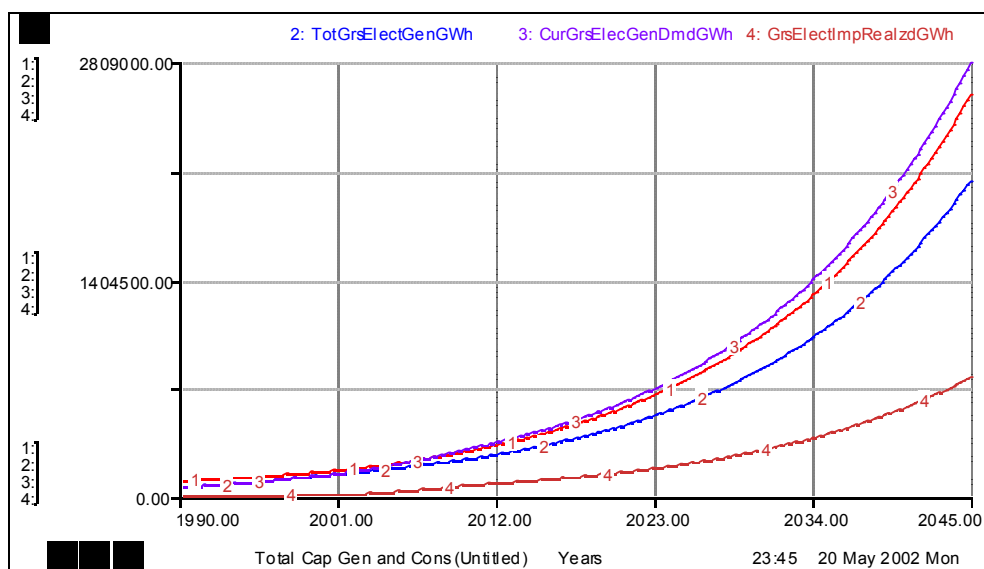

Figure 32. Total Electricity Capacity, Generation, Demand and Import (Gwh) without Savings. (Historical policies continued)

- *Renewable/ Non-Renewable Equally Weighted Policy* with Combined Cost and Emission Based Non-Renewable İnstallation Scenario

It is seen in Figure 33 that electricity need is met by the capacity. Since the installation policy changes in 1998, firstly a capacity excess occurs but after 2012 the capacity balances itself in the long term. It is also important that the decrease in network losses also decreases the discrepancy between capacity and electricity generation. It is seen that there is no electricity import. Figure 34 shows the levels of total cost and emission. The import levels of non-renewable sources are also illustrated in Figure 35.
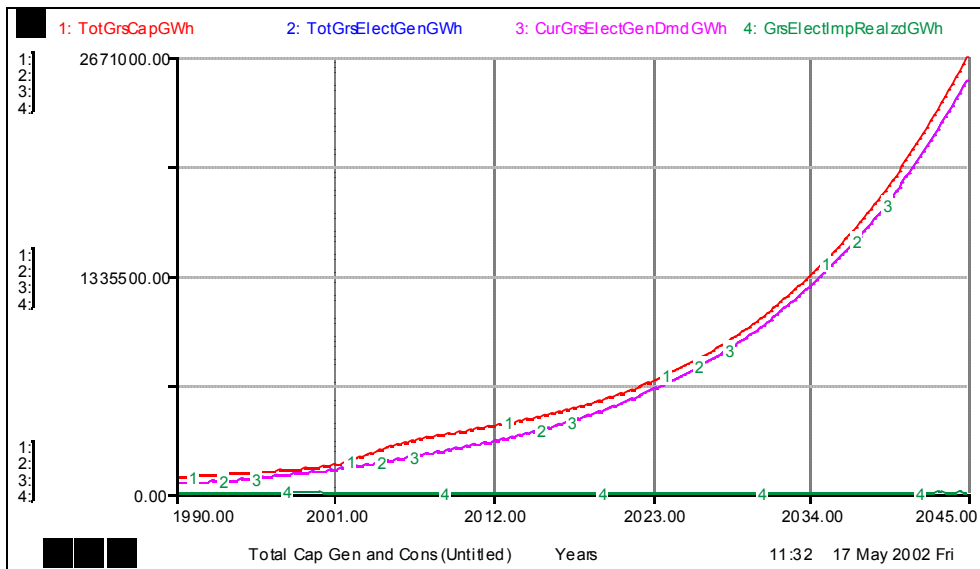

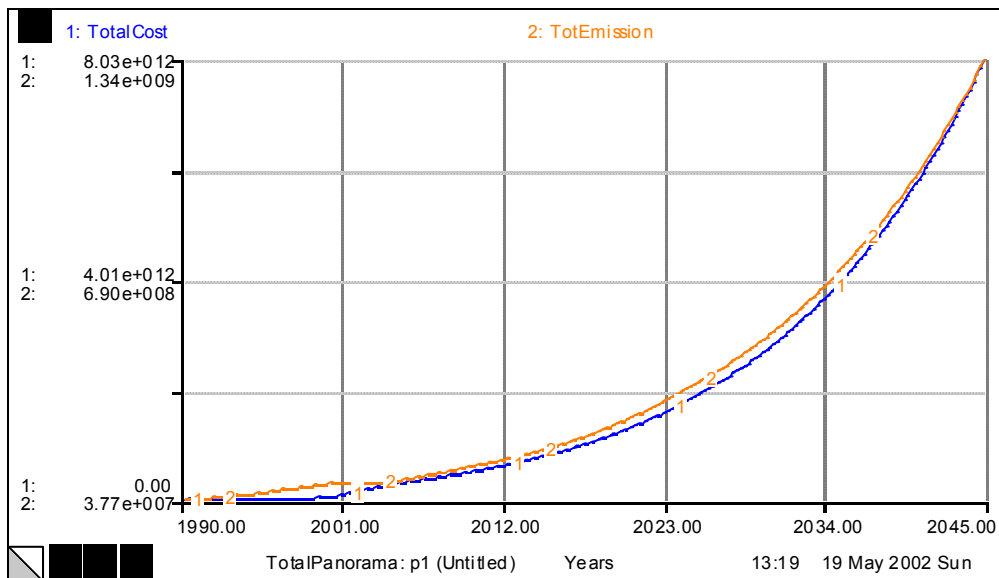Figure 33. Total Electricity Capacity, Generation, Demand and Import with Savings

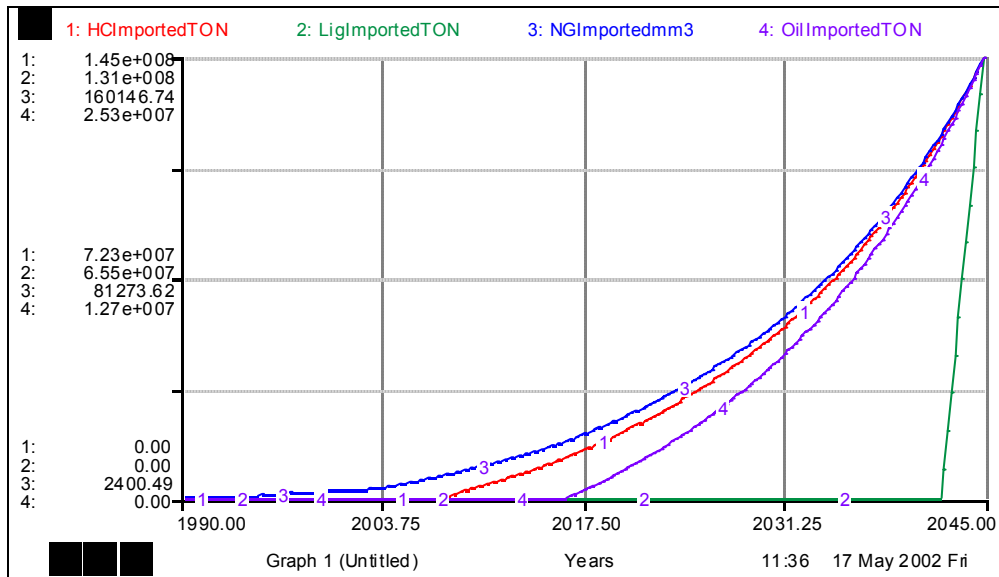Figure 34. Total Cost and Emission with Savings

Figure 35. Fuel Imports with Savings

- *Renewable Oriented Policy* with combined cost and emission based renewable installation scenario.

With this policy, almost the same behavior of renewable/nonrenewable equally weighted policy is observed. Only the levels of emission and costs differ.

Table 6 shows the final values of main variables with and without savings in the long term. The table also illustrates base run results for each scenario for comparison. It is seen that renewable oriented policy has the second lowest capacity utilization, after the base run, with 89 per cent under pessimistic scenario and 94 per cent under optimistic scenario. The minimum accumulated emission level is obtained by renewable-oriented scenario, which is 42 per cent lower than the level of base run in pessimistic demand scenario and 35 per cent lower in optimistic demand scenario with savings. On the other hand, lower accumulated costs are realized by non-renewable oriented policy. Just as in Table 5, observe again that costs of electricity import are no included in the cumulative cost figures, so that cumulative costs in the BASE RUN (involving large imports) significantly underestimate the actual costs. Also observe that when all policies are compared under with and without savings scenarios (upper and lower values of Table 6) installed capacities, gross electricity generation, cumulative costs and emissions are all reduced in the savings case.

Table 6. Comparative values of main variables at year 2045

	Historical Policy Continued (BASE RUN)	Renewable and Non-Renewable Equally Weighted Policy	% change relative to base run	Renewable Oriented Policy	% change relative to base run	Non-Renewable Oriented Policy	% change relative to base run
Without Savings							
Yearly Gross Electricity Demand (GWh)	2,809,338	2,809,338		2,809,338		2,809,338	
Yearly Total Gross Capacity (GWh)	2,602,731	2,970,358		3,163,656		2,795,393	
Yearly Gross Electricity Generation (GWh)	2,043,448	2,809,338		2,809,338		2,795,393	
Capacity Utilization (%)	79	95		89		100	
Accumulated Electricity Import (GWh)	10,575,233	966	*-100*	1,030	*-100*	374,738	*-96*
Accumulated Emission (TON)	18,307,022,490	22,315,047,564	*22*	10,420,223,636	*-43*	35,810,450,735	*96*
Accumulated Cost (USD)	1,371,923,799,802	8,975,694,543,560	*554*	15,721,991,293,058	*1,046*	1,898,757,227,591	*38*
With Savings							
Yearly Gross Electricity Demand (GWh)	2,529,809	2,529,809		2,529,809		2,529,809	
Yearly Total Gross Capacity (GWh)	2,343,684	2,670,608		2,843,256		2,515,024	
Yearly Gross Electricity Generation (GWh)	1,840,769	2,529,809		2,529,809		2,515,024	
Capacity Utilization (%)	79	95		89		100	
Accumulated Electricity Import (GWh)	9,469,188	1,147	*-100*	1,233	*-100*	366,346	*-96*
Accumulated Emission (TON)	16,680,081,913	20,243,447,316	*21*	9,729,129,559	*-42*	32,212,823,513	*93*
Accumulated Cost (USD)	1,240,717,418,284	8,025,681,996,049	*547*	13,970,948,914,251	*1,026*	1,714,442,356,681	*38*

CONCLUSION

The electricity need of Turkey has been met mostly by non-renewable sources. The main goal of this study is to investigate whether renewable sectors can play an important role in the total electricity generation, to meet the electricity need of Turkey in the future, with different allocation policies. This question is investigated by constructing a dynamic simulation model which represents the energy planning dynamics in electric power sector in Turkey. The validation tests are mostly based on information published by World Energy Council Turkish National Committee in 1998. Since much of the data on technological aspects of power plants and fuel production rates differ year by year, the averages of the related parameters are used in the model. Nevertheless, validity tests show that the model-generated behavior is consistent with the literature and available data and the model adequately represents the electricity generation, power plant installation and reserve depletion structures of Turkey.

First, a cost-oriented policy is used in the allocation of future electricity need to different energy sources and different renewable and non-renewable installation priority policies are tested. If the renewable and non-renewable sectors have equal priorities for future investments, electricity import does not occur and renewable sectors capacity grows significantly. In case of emission-oriented scenarios, the behavior of the system does not change with respect to renewable versus non-renewable priorities. The same fundamental behaviors emerge with different costs and emissions. Generally, emission-based allocation scenarios create lower emission level, but high installation and operation costs. With respect to the emission level, the best results are obtained from renewable-oriented scenarios, but they produce high capacity installation costs. The emission level and installation and operation costs of non-renewable sectors are finally combined to yield combined installation fractions. Renewable and non-renewable policies result in different levels of capacity, cost and emission.

A conservation oriented scenario is also implemented by assuming a gradual reduction in network losses and an increase in consumption efficiency. Long term analysis, until year 2045, is done with or without conservation assumptions over a period of 10 years. Combined cost and emission based non-renewable installation policy is used under two projections; optimistic and pessimistic ones.

Since energy production is a very broad and complex issue, the model can be extended in different aspects. The demand side of the model can be influenced by the capacity excess and a feedback loop can be constructed between installed capacity and demand. Furthermore, the demand can be enhanced in itself. Moreover, emission and cost levels can directly influence the capacity installation and electricity generation fractions, constituting further feedback loops that allow more adaptive installation and allocation decision.

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Appendix 1. Model Structure

Appendix 2: Model Equations

Costs and Emissions

TotalCost = TotalCostofNREN+TotalCostofREN

TotalCostofNREN = HCPTotalCost+LPTotalCost+NGPTotalCost+OPTotalCost

TotalCostofREN = GTPTotalCost+HPTotalCost+SHPTotalCost+SPTotalCost+WPTotalCost

TotEmisNREN = EmisRelbyHCP+EmisRelbyLP+EmisRelbyNGP+EmisRelbyOP

TotEmisREN = EmisRelbyGTP+EmisnRelbyHP+EmisRelbySHP+EmisRelbyWP+EmisRelbySP

TotEmission = TotEmisNREN+TotEmisREN

CURRENT ELECTRICITY NEED

CurActGrsElectConsGW = CurGrsElectConsGWh*(1-CurSavingsEffect)

CurGrsElectGenAllocbyNationICGWh = MIN (CurGrsElectGenDmdGWh,TotGrsCapGWh)

CurGrsElectGenDmdGWh = CurActGrsElectConsGW*(1+InternalConsRatio)

CurNetElectConsGWh = CurActGrsElectConsGW*(1-NetworkLossRatio)

GrsElectImpExpectdGWh = CurGrsElectGenDmdGWh-CurGrsElectGenAllocbyNationICGWh

GrsElectImpRealzdGWh = CurGrsElectGenDmdGWh-TotGrsElectGenGWh

InternalConsRatio = 0.034

TotDomNetElectConsGWh = TotNetElectGenGWh*(1-NetworkLossRatio)

TotGrsCapGWh = TotNRENICGWh+TotRENICGWh

TotGrsElectGenGWh = TotGrsNRENElectGenGWh+TotGrsRENElectGenGWh

TotGrsNRENElectGenGWh = GrsElecGenbyHCPGWh+GrsElecGenbyNGPGWh+GrsElecGenbyOilGWh+GrsElecGenbyLPGWh

TotGrsRENElectGenGWh =
GrsElectGebyWPGWh+GrsElectGenbyGTPGWh+GrsElectGenbyHPGWh+GrsElectGenbySHPGWh+GrsElectGenbySPGWh

TotICMW = TotNREN_IC_MW+TotREN_IC_MW

TotNetCapAvlforEndUseGWh = TotNetCapGWh*(1-NetworkLossRatio)

TotNetCapGWh = TotGrsCapGWh*(1-InternalConsRatio)

TotNetElectGenGWh = TotGrsElectGenGWh*(1-InternalConsRatio)

TotNRENICGWh = TotHCPICGWh+TotLPICGWh+TotNGICGWh+TotOPICGWh

TotNREN_IC_MW = TotHCPIC_MW+TotLPIC_MW+TotNGPIC_MW+TotOPIC_MW

TotRENICGWh = TotGTPICGWh+TotHPICGWh+TotSHPICGWh+TotSPICGWh+TotWPICGWh

TotREN_IC_MW = TotGTPIC_MW+TotHPIC_MW+TotSHPIC_MW+TotSPIC_MW+TotWPIC_MW

CurSavingsEffect = GRAPH(time)

(1990, 0.00), (1991, 0.00), (1992, 0.00), (1993, 0.00), (1994, 0.00), (1995, 0.00), (1996, 0.00), (1997, 0.00), (1998, 0.00), (1999, 0.00), (2000, 0.0025), (2001, 0.0055), (2002, 0.009), (2003, 0.012), (2004, 0.0155), (2005, 0.0215), (2006, 0.0295), (2007, 0.0375), (2008, 0.0465), (2009, 0.0575), (2010, 0.072), (2011, 0.0825), (2012, 0.089), (2013, 0.093), (2014, 0.0965), (2015, 0.0995), (2016, 0.0995), (2017, 0.0995), (2018, 0.0995), (2019, 0.0995), (2020, 0.0995)

NetworkLossRatio = GRAPH(time)

(1990, 0.18), (1991, 0.18), (1992, 0.18), (1993, 0.18), (1994, 0.18), (1995, 0.18), (1996, 0.18), (1997, 0.18), (1998, 0.18), (1999, 0.18), (2000, 0.179), (2001, 0.178), (2002, 0.176), (2003, 0.174), (2004, 0.17), (2005, 0.166), (2006, 0.16), (2007, 0.15), (2008, 0.138), (2009, 0.124), (2010, 0.1), (2011, 0.1), (2012, 0.1), (2013, 0.1), (2014, 0.1), (2015, 0.1)

FUTURE ELECTRICITY NEED

FutActGrsConsGWh = FutGrsElecConsGWh*(1-FutSavingsEffect)

FutGrsElectDmdGWh = FutActGrsConsGWh*(1+InternalConsRatio)

FutNRENNeedGWh = FutGrsElectDmdGWh*NRENPriority

FutRENNeedGWh = FutGrsElectDmdGWh*RENPriorityAdjusted

NRENPriority = 1-RENPriorityAdjusted

RENinitialPriority = 0.65

RENInstFracAdjust = GTP_Inst_Frac+HP_Inst_Frac+SHP_Inst_Frac+SPInstFrac+WPInstFrac

RENPriorityAdjusted = IF TIME<1999 THEN min(RENinitialPriority,(TotRENPotGWh/FutGrsElectDmdGWh)) ELSE min(RENSmthPriorityReq,(TotRENPotGWh/FutGrsElectDmdGWh))

RENPriorityRequested = 0.5

RENSmthPriorityReq = RENPriorityRequested*TransEff+RENinitialPriority*(1-TransEff)

TotRENPotGWh = HPpotNotUsedGWhyear+WPpotNotUsedGWhYear+SHPpotNotUsedGWhyear+GTPpotNotUsedGWhyear+SP_potNotUsedGWhYear

FutSavingsEffect = GRAPH(time)

(1990, 0.00), (1991, 0.00), (1992, 0.00), (1993, 0.00), (1994, 0.00), (1995, 0.003), (1996, 0.006), (1997, 0.009), (1998, 0.012), (1999, 0.016), (2000, 0.022), (2001, 0.03), (2002, 0.038), (2003, 0.047), (2004, 0.058), (2005, 0.072), (2006, 0.083), (2007, 0.089), (2008, 0.093), (2009, 0.097), (2010, 0.1), (2011, 0.1), (2012, 0.1), (2013, 0.1), (2014, 0.1), (2015, 0.1)

GEOTHERMAL POWER

GTPIC1_MW(t) = GTPIC1_MW(t - dt) + (GTP_Online_Rate - GTPRetire1) * dt

INIT GTPIC1_MW = 15/3

INFLOWS:

GTP_Online_Rate = GTPUC_MW/GTPUC_Delay

OUTFLOWS:

GTPRetire1 = GTPIC1_MW/(GTPIC_Delay/3)

GTPIC2_MW(t) = GTPIC2_MW(t - dt) + (GTPRetire1 - GTPRetire2) * dt

INIT GTPIC2_MW = 15/3

INFLOWS:

GTPRetire1 = GTPIC1_MW/(GTPIC_Delay/3)

OUTFLOWS:

GTPRetire2 = GTPIC2_MW/(GTPIC_Delay/3)

GTPIC3_MW(t) = GTPIC3_MW(t - dt) + (GTPRetire2 - GTPRetire3) * dt

INIT GTPIC3_MW = 15/3

INFLOWS:

GTPRetire2 = GTPIC2_MW/(GTPIC_Delay/3)

OUTFLOWS:

GTPRetire3 = GTPIC3_MW/(GTPIC_Delay/3)

GTPpotNotUsedGWhyear(t) = GTPpotNotUsedGWhyear(t - dt) + (GTP_Pot_Added - GTPotUsage) * dt

INIT GTPpotNotUsedGWhyear = 18750-85

INFLOWS:

GTP_Pot_Added = GTPRetire3*GTPAvailability*GTPCapUtil*MaxWorkingHour

OUTFLOWS:

GTPotUsage = GTPInitiateGWh

GTPTotalCost(t) = GTPTotalCost(t - dt) + (GTPInstallCost + GTPOperCost) * dt

INIT GTPTotalCost = 0

INFLOWS:

GTPInstallCost = GTPInstalled*GTPInsCostperMW

GTPOperCost = GrsElectGenbyGTPGWh*GTPOperCostperGWh

GTPUC_MW(t) = GTPUC_MW(t - dt) + (GTPInstalled - GTP_Online_Rate) * dt

INIT GTPUC_MW = 0

INFLOWS:

GTPInstalled = GTPotUsage/(GTPCapUtil*GTPAvailability*MaxWorkingHour)*1000

OUTFLOWS:

GTP_Online_Rate = GTPUC_MW/GTPUC_Delay

DesiredUC_GTP = GTPRetire3*GTPUC_Delay

EmisRelbyGTP = GrsElectGenbyGTPGWh*GTPEmisTONperGWh

FutGTPNeedAllocGWh = IF TIME<1999 THEN (GTPFracInitial*FutRENNeedGWh) ELSE (FutRENNeedGWh*GTPSmthInsFrac)

GrsElectGenbyGTPGWh = IF TIME<1999 THEN (CurGrsElectGenAllocbyNationICGWh*GTPCapFract_Initial) ELSE (CurGrsElectGenAllocbyNationICGWh*GTPSmthCapFract)

GTPAvailability = 0.69

GTPcapFract = TotGTPICGWh/TotGrsCapGWh

GTPCapFract_Initial = .001

GTPCapUtil = 1

GTPEmisTONperGWh = 75

GTPFracInitial = 0.002

GTPIC_Delay = 30

GTPInitiateGWh = MIN(MAX(0,(InstallGTP_MW*GTPAvailability*GTPCapUtil*MaxWorkingHour/1000)),GTPpotNotUsedGWhyear)

GTPInsCostperMW = 1450000

GTPInstFractRevised = GTP_Inst_Frac/RENInstFracAdjust

GTPOperCostperGWh = 0.0177*1000000

GTPSmthCapFract = GTPcapFract*TransEff+GTPCapFract_Initial*(1-TransEff)

GTPSmthInsFrac = (GTPFracInitial*(1-TransEff))+(GTPInstFractRevised*TransEff)

GTPUC_Delay = 2

GTP_Inst_Frac = GTP_Poten_Rate*GTP_Priority

GTP_Poten_Rate = GTPpotNotUsedGWhyear/TotRENPotGWh

GTP_Priority = 1

InstallGTP_MW = (NeedGTP_MW-TotGTPIC_MW)/AT1+(DesiredUC_GTP-GTPUC_MW)/AT2+GTPRetire3

NeedGTP_MW = FutGTPNeedAllocGWh/GTPAvailability/GTPCapUtil/MaxWorkingHour*1000

TotGTPICGWh = TotGTPIC_MW*GTPAvailability*GTPCapUtil*MaxWorkingHour/1000

TotGTPIC_MW = GTPIC1_MW+GTPIC2_MW+GTPIC3_MW

HARD COAL POWER

HCPIC1_MW(t) = HCPIC1_MW(t - dt) + (HCP_Online_Rate - HCPRetire1) * dt

INIT HCPIC1_MW = 332/3

INFLOWS:

HCP_Online_Rate = HCPUC_MW/HCUCDelay

OUTFLOWS:

HCPRetire1 = HCPIC1_MW/HCPIC_Delay/3

HCPIC2_MW(t) = HCPIC2_MW(t - dt) + (HCPRetire1 - HCPRetire2) * dt

INIT HCPIC2_MW = 332/3

INFLOWS:

HCPRetire1 = HCPIC1_MW/HCPIC_Delay/3

OUTFLOWS:

HCPRetire2 = HCPIC2_MW/HCPIC_Delay/3

HCPIC3_MW(t) = HCPIC3_MW(t - dt) + (HCPRetire2 - HCPRetire3) * dt

INIT HCPIC3_MW = 332/3

INFLOWS:

HCPRetire2 = HCPIC2_MW/HCPIC_Delay/3

OUTFLOWS:

HCPRetire3 = HCPIC3_MW/HCPIC_Delay/3

HCPTotalCost(t) = HCPTotalCost(t - dt) + (HCPInstallCost + HCPOperCost) * dt

INIT HCPTotalCost = 0

INFLOWS:

HCPInstallCost = HCP_Installed*HCPInsCostperMW

HCPOperCost = GrsElecGenbyHCPGWh*HCPOperCostperGWh

HCPUC_MW(t) = HCPUC_MW(t - dt) + (HCP_Installed - HCP_Online_Rate) * dt

INIT HCPUC_MW = 150

INFLOWS:

HCP_Installed = max(0,InstallHCP_MW)

OUTFLOWS:

HCP_Online_Rate = HCPUC_MW/HCUCDelay

HCReserveTON(t) = HCReserveTON(t - dt) + (- YearlyHCDepletionTON) * dt

INIT HCReserveTON = (1124000000+23323000)

OUTFLOWS:

YearlyHCDepletionTON = DomGenbyHCPGWh*HCUseperGWh

CurHCPNeedAllocGWh = IF TIME<1999 THEN (CurGrsElectGenAllocbyNationICGWh*HCCapFract_Initial) ELSE (CurGrsElectGenAllocbyNationICGWh*HCSmthCapFract)

DesiredUC_HC = HCPRetire3*HCUCDelay

DomGenbyHCPGWh = min(GrsElecGenbyHCPGWh,DomHCResPotenGWh)

DomHCResPotenGWh = YearlyMaxHCProd*HCPPConsRatio/HCUseperGWh/ProcessTime

EmisRelbyHCP = GrsElecGenbyHCPGWh*HCEmisTONperGWh

FutHCPNeedAllocGWh = IF TIME<1999 THEN (FutNRENNeedGWh*HCP_InstFractInitial) ELSE (FutNRENNeedGWh*HCPSmthInstFract*HC_Priority)

GrsElecGenbyHCPGWh = MIN (TotHCPICGWh,CurHCPNeedAllocGWh)

HCAvailability = .80

HCCapFract_Initial = .024

HCCapUtil = 1

HCEmisTONperGWh = 1112.5

HCImportedTON = max(0,(HCTotalUsedTON-YearlyHCDepletionTON))

HCPIC_Delay = 30

HCPInsCostperMW = 1450000

HCPOperCostperGWh = 0.035*1000000

HCPPConsRatio = .16

HCProdFr = 0.05

HCPSmthInstFract = HCP_InstFract*TransEff+HCP_InstFractInitial*(1-TransEff)

HCP_InstFract = .16

HCP_InstFractInitial = 0

HCResRateInTotal = TotalPotHCEnergyGWh/TotalNonRenReserveGWh

HCSmthCapFract = HC_CapFract*TransEff+HCCapFract_Initial*(1-TransEff)

HCTotalUsedTON = GrsElecGenbyHCPGWh*HCUseperGWh

HCUCDelay = 4

HCUseperGWh = 813

HC_CapFract = TotHCPICGWh/TotGrsCapGWh

HC_Priority = 1

InstallHCP_MW = (NeedHCP_MW-TotHCPIC_MW)/AT1+(DesiredUC_HC-HCPUC_MW)/AT2+HCPRetire3

NeedHCP_MW = FutHCPNeedAllocGWh/HCAvailability/HCCapUtil/MaxWorkingHour*1000

TotalPotHCEnergyGWh = HCReserveTON*HCPPConsRatio/HCUseperGWh/ProcessTime

TotHCPICGWh = (HCPIC1_MW+HCPIC2_MW+HCPIC3_MW)*HCAvailability*HCCapUtil*MaxWorkingHour/1000

TotHCPIC_MW = HCPIC1_MW+HCPIC2_MW+HCPIC3_MW

YearlyMaxHCProd = HCReserveTON*HCProdFr

HYDROPOWER

HPIC1MW(t) = HPIC1MW(t - dt) + (HP_Online_Rate - HPRetire1) * dt

INIT HPIC1MW = (6764.3-186.05)/3

INFLOWS:

HP_Online_Rate = HP_UC_MW/HPUC_Delay

OUTFLOWS:

HPRetire1 = HPIC1MW/(HPIC_Delay/3)

HPIC2MW(t) = HPIC2MW(t - dt) + (HPRetire1 - HPRetire2) * dt

INIT HPIC2MW = (6764.3-186.05)/3

INFLOWS:

HPRetire1 = HPIC1MW/(HPIC_Delay/3)

OUTFLOWS:

HPRetire2 = HPIC2MW/(HPIC_Delay/3)

HPIC3MW(t) = HPIC3MW(t - dt) + (HPRetire2 - HPRetire3) * dt

INIT HPIC3MW = (6764.3-186.05)/3

INFLOWS:

HPRetire2 = HPIC2MW/(HPIC_Delay/3)

OUTFLOWS:

HPRetire3 = HPIC3MW/(HPIC_Delay/3)

HPpotNotUsedGWhyear(t) = HPpotNotUsedGWhyear(t - dt) + (HP_Pot_Added - HPotUsage) * dt

INIT HPpotNotUsedGWhyear = (430000-23147.6)-691.2

INFLOWS:

HP_Pot_Added = HPRetire3*HPAvailability*HPCapUtil*MaxWorkingHour

OUTFLOWS:

HPotUsage = HPInitiateGWh

HPTotalCost(t) = HPTotalCost(t - dt) + (HPInstallCost + HPOperCost) * dt

INIT HPTotalCost = 0

INFLOWS:

HPInstallCost = HPInstalled*HPInsCostperMW

HPOperCost = GrsElectGenbyHPGWh*HPOperCostperGWh

HP_UC_MW(t) = HP_UC_MW(t - dt) + (HPInstalled - HP_Online_Rate) * dt

INIT HP_UC_MW = 2806.7

INFLOWS:

HPInstalled = HPotUsage/(HPCapUtil*HPAvailability*MaxWorkingHour)*1000

OUTFLOWS:

HP_Online_Rate = HP_UC_MW/HPUC_Delay

DesiredUC_HP = HPRetire3*HPUC_Delay

ElectGenbySmlBigHYDROICGWh = GrsElectGenbyHPGWh+GrsElectGenbySHPGWh

EmisnRelbyHP = GrsElectGenbyHPGWh*HPEmisTONperGWh

FutHPNeedAllocGWh = IF TIME<1999 THEN (HPFracInitial*FutRENNeedGWh) ELSE (FutRENNeedGWh*HPSmthInsFrac)

GrsElectGenbyHPGWh = IF TIME<1999 THEN (CurGrsElectGenAllocbyNationICGWh*HPCapFract_Initial) ELSE (CurGrsElectGenAllocbyNationICGWh*HPSmthCapFract)

HPAvailability = 0.45

HPcapFract = TotHPICGWh/TotGrsCapGWh

HPCapFract_Initial = .393

HPCapUtil = 1

HPEmisTONperGWh = 200

HPFracInitial = .971

HPIC_Delay = 45

HPInitiateGWh = MIN(MAX(0,(InstallHP_MW*HPAvailability*HPCapUtil*MaxWorkingHour/1000)),HPpotNotUsedGWhyear)

HPInsCostperMW = 1200000

HPInstFractRevised = HP_Inst_Frac/RENInstFracAdjust

HPOperCostperGWh = 0.0005*1000000

HPSmthCapFract = HPcapFract*TransEff+HPCapFract_Initial*(1-TransEff)

HPSmthInsFrac = (HPFracInitial*(1-TransEff))+(HPInstFractRevised*TransEff)

HPUC_Delay = 6

HP_Inst_Frac = HP_Poten_Rate*HP_Priority

HP_Poten_Rate = HPpotNotUsedGWhyear/TotRENPotGWh

HP_Priority = 1

InstallHP_MW = (NeedHP_MW-TotHPIC_MW)/AT1+(DesiredUC_HP-HP_UC_MW)/AT2+HPRetire3

NeedHP_MW = FutHPNeedAllocGWh/HPAvailability/HPCapUtil/MaxWorkingHour*1000

SmlBigHYDROICGWh = TotHPICGWh+TotSHPICGWh

SmlBigHYDROIC_MW = TotHPIC_MW+TotSHPIC_MW

TotHPICGWh = TotHPIC_MW*HPAvailability*HPCapUtil*MaxWorkingHour/1000

TotHPIC_MW = HPIC1MW+HPIC2MW+HPIC3MW

TransEff = GRAPH(time)

(1990, 0.00), (1991, 0.00), (1992, 0.00), (1993, 0.00), (1994, 0.00), (1995, 0.00), (1996, 0.00), (1997, 0.00), (1998, 0.00), (1999, 0.095), (2000, 0.245), (2001, 0.675), (2002, 0.88), (2003, 1.00)

LIGNITE POWER

LigniteReserveTON(t) = LigniteReserveTON(t - dt) + (- YearlyLigDepTON) * dt

INIT LigniteReserveTON = (8374372000+462457000)

OUTFLOWS:

YearlyLigDepTON = DomGenbyLPGWh*LigUseperGWh

LPIC1_MW(t) = LPIC1_MW(t - dt) + (LP_Online_Rate - LPRetire1) * dt

INIT LPIC1_MW = 4896.2/3

INFLOWS:

LP_Online_Rate = LPUNConsMW/LPUCDelay

OUTFLOWS:

LPRetire1 = LPIC1_MW/LPIC_Delay/3

LPIC2_MW(t) = LPIC2_MW(t - dt) + (LPRetire1 - LPRetire2) * dt

INIT LPIC2_MW = 4896.2/3

INFLOWS:

LPRetire1 = LPIC1_MW/LPIC_Delay/3

OUTFLOWS:

LPRetire2 = LPIC2_MW/LPIC_Delay/3

LPIC3_MW(t) = LPIC3_MW(t - dt) + (LPRetire2 - LPRetire3) * dt

INIT LPIC3_MW = 4896.2/3

INFLOWS:

LPRetire2 = LPIC2_MW/LPIC_Delay/3

OUTFLOWS:

LPRetire3 = LPIC3_MW/LPIC_Delay/3

LPTotalCost(t) = LPTotalCost(t - dt) + (LPInstallCost + LPOperCost) * dt

INIT LPTotalCost = 0

INFLOWS:

LPInstallCost = LP_Installed*LPInstCostperMW

LPOperCost = GrsElecGenbyLPGWh*LPOperCostperGWh

LPUNConsMW(t) = LPUNConsMW(t - dt) + (LP_Installed - LP_Online_Rate) * dt

INIT LPUNConsMW = 1212

INFLOWS:

LP_Installed = max(0,InstallLP_MW)

OUTFLOWS:

LP_Online_Rate = LPUNConsMW/LPUCDelay

AT1 = 2

AT2 = 2

CurLPNeedAllocGWh = IF TIME<1999 THEN (CurGrsElectGenAllocbyNationICGWh*LigCapFract_Initial) ELSE (CurGrsElectGenAllocbyNationICGWh*LigSmthCapFract)

DesiredUC_LP = LPRetire3*LPUCDelay

DomGenbyLPGWh = min(GrsElecGenbyLPGWh,DomLigResPotGWh)

DomLigResPotGWh = YearlyMaxLigProdTON*LigPPConsRatio/LigUseperGWh

EmisRelbyLP = GrsElecGenbyLPGWh*LigEmisTONperGWh

FutLPNeedAllocGWh = IF TIME<1999 THEN (FutNRENNeedGWh*LP_InstFractInitial) ELSE (FutNRENNeedGWh*LigSmthInstFract*LP_Priority)

GrsElecGenbyLPGWh = MIN (TotLPICGWh,CurLPNeedAllocGWh)

InstallLP_MW = (NeedLP_MW-TotLPIC_MW)/AT1+(DesiredUC_LP-LPUNConsMW)/AT2+LPRetire3

LigCapFract_Initial = .316

LigEmisTONperGWh = 1112.5

LigImportedTON = Max(0,(LigTotalUsedTON-YearlyLigDepTON))

LigProdFr = 0.10

LigResRateInTotal = TotalLigResGWh/TotalNonRenReserveGWh

LigSmthCapFract = Lig_CapFract*TransEff+LigCapFract_Initial*(1-TransEff)

LigSmthInstFract = LP_InstFract*TransEff+LP_InstFractInitial*(1-TransEff)

LigTotalUsedTON = GrsElecGenbyLPGWh*LigUseperGWh

LigUseperGWh = 1593

Lig_CapFract = TotLPICGWh/TotGrsCapGWh

LPAvailability = 0.90

LPCapUtil = 1

LPIC_Delay = 30

LPInstCostperMW = 1600000

LPOperCostperGWh = 0.025*1000000

LPUCDelay = 4

LP_InstFract = .20

LP_InstFractInitial = .53

LP_Priority = 1

MaxWorkingHour = 365*24

NeedLP_MW = FutLPNeedAllocGWh/LPAvailability/LPCapUtil/MaxWorkingHour*1000

ProcessTime = 1

TotalLigResGWh = (LigniteReserveTON*LigPPConsRatio/LigUseperGWh)/ProcessTime

TotalNonRenReserveGWh = TotalLigResGWh+TotalPotNGEnergyGWh+TotalPotOilEnergyGWh+TotalPotHCEnergyGWh

TotLPICGWh = TotLPIC_MW*LPAvailability*LPCapUtil*MaxWorkingHour/1000

TotLPIC_MW = LPIC1_MW+LPIC2_MW+LPIC3_MW

YearlyMaxLigProdTON = LigniteReserveTON*LigProdFr

YearlyMaxLinProdGWhyear = (YearlyMaxLigProdTON/LigUseperGWh)/ProcessTime

LigPPConsRatio = GRAPH(time)

(1990, 0.65), (1991, 0.66), (1992, 0.685), (1993, 0.715), (1994, 0.755), (1995, 0.795), (1996, 0.825), (1997, 0.85), (1998, 0.85)

NATURAL GAS POWER

NGPIC1_MW(t) = NGPIC1_MW(t - dt) + (NGP_Online_Rate - NGPRetire1) * dt

INIT NGPIC1_MW = 2210/3

INFLOWS:

NGP_Online_Rate = NGPUC_MW/NGUCDelay

OUTFLOWS:

NGPRetire1 = NGPIC1_MW/NGPIC_Delay/3

NGPIC2_MW(t) = NGPIC2_MW(t - dt) + (NGPRetire1 - NGPRetire2) * dt

INIT NGPIC2_MW = 2210/3

INFLOWS:

NGPRetire1 = NGPIC1_MW/NGPIC_Delay/3

OUTFLOWS:

NGPRetire2 = NGPIC2_MW/NGPIC_Delay/3

NGPIC3_MW(t) = NGPIC3_MW(t - dt) + (NGPRetire2 - NGPRetire3) * dt

INIT NGPIC3_MW = 2210/3

INFLOWS:

NGPRetire2 = NGPIC2_MW/NGPIC_Delay/3

OUTFLOWS:

NGPRetire3 = NGPIC3_MW/NGPIC_Delay/3

NGPTotalCost(t) = NGPTotalCost(t - dt) + (NGPInstallCost + NGPOperCost) * dt

INIT NGPTotalCost = 0

INFLOWS:

NGPInstallCost = NGP_Installed*NGInsCostperMW

NGPOperCost = GrsElecGenbyNGPGWh*NGPOperCostperGWh

NGPUC_MW(t) = NGPUC_MW(t - dt) + (NGP_Installed - NGP_Online_Rate) * dt

INIT NGPUC_MW = 345.4

INFLOWS:

NGP_Installed = max(0,InstallNGP_MW)

OUTFLOWS:

NGP_Online_Rate = NGPUC_MW/NGUCDelay

NGReservemm3(t) = NGReservemm3(t - dt) + (- YearlyNGDepmm3) * dt

INIT NGReservemm3 = (18530-3537+2219)

OUTFLOWS:

YearlyNGDepmm3 = DomGenbyNGPGWh*NGUseperGWh

CurtNGNeedAllocGWh = IF TIME<1999 THEN (CurGrsElectGenAllocbyNationICGWh*NGCapFract_Initial) ELSE (CurGrsElectGenAllocbyNationICGWh*NGSmthCapFract)

DesiredUC_OP = NGPRetire3*NGUCDelay

DomGenbyNGPGWh = min(GrsElecGenbyNGPGWh,DomNGResPotenGWh)

DomNGResPotenGWh = YearlyMaxNGProd*NGPPConsRatio/NGUseperGWh/ProcessTime

EmisRelbyNGP = GrsElecGenbyNGPGWh*NGEmismm3perGWh

FutNGPNeedAllocGWh = IF TIME<1999 THEN (FutNRENNeedGWh*NG_InstFractInitial) ELSE (FutNRENNeedGWh*NGSmthInstFract*NGP_Priority)

GrsElecGenbyNGPGWh = MIN (TotNGICGWh,CurtNGNeedAllocGWh)

InstallNGP_MW = (NeedNGP_MW-TotNGPIC_MW)/AT1+(DesiredUC_OP-NGPUC_MW)/AT2+NGPRetire3

NeedNGP_MW = FutNGPNeedAllocGWh/NGAvailability/NGCapUtil/MaxWorkingHour*1000

NGAvailability = 0.85

NGCapFract_Initial = .187

NGCapUtil = 1

NGEmismm3perGWh = 825

NGImportedmm3 = Max (0,(NGTotalUsedmm3-YearlyNGDepmm3))

NGInsCostperMW = 680000

NGPIC_Delay = 40

NGPOperCostperGWh = 0.03*1000000

NGPPConsRatio = .60

NGP_InstFract = .55

NGP_Priority = 1

NGResRateInTotal = TotalPotNGEnergyGWh/TotalNonRenReserveGWh

NGSmthCapFract = NG_CapFract*TransEff+NGCapFract_Initial*(1-TransEff)

NGSmthInstFract = NGP_InstFract*TransEff+NG_InstFractInitial*(1-TransEff)

NGTotalUsedmm3 = GrsElecGenbyNGPGWh*NGUseperGWh

NGUCDelay = 3

NGUseperGWh = 0.238

NG_CapFract = TotNGICGWh/TotGrsCapGWh

NG_InstFractInitial = .47

TotalPotNGEnergyGWh = NGReservemm3*NGPPConsRatio/NGUseperGWh/ProcessTime

TotNGICGWh = TotNGPIC_MW*NGAvailability*NGCapUtil*MaxWorkingHour/1000

TotNGPIC_MW = NGPIC1_MW+NGPIC2_MW+NGPIC3_MW

YearlyMaxNGProd = NGReservemm3*NGProdFr

NGProdFr = GRAPH(time)

(1990, 0.01), (1991, 0.0115), (1992, 0.017), (1993, 0.0285), (1994, 0.0605), (1995, 0.0755), (1996, 0.0845), (1997, 0.0935), (1998, 0.1)

OIL POWER

CrudeOilReserveTON(t) = CrudeOilReserveTON(t - dt) + (- YearlyOilDepTON) * dt

INIT CrudeOilReserveTON = (977185000-106586000+33725000)

OUTFLOWS:

YearlyOilDepTON = DomGenbyOPGWh*OilUseperGWh

OPIC2MW(t) = OPIC2MW(t - dt) + (OPRetire1 - OPRetire2) * dt

INIT OPIC2MW = (1552+546)/3

INFLOWS:

OPRetire1 = OPICMW/OPIC_Delay/3

OUTFLOWS:

OPRetire2 = OPIC2MW/OPIC_Delay/3

OPIC3MW(t) = OPIC3MW(t - dt) + (OPRetire2 - OPRetire3) * dt

INIT OPIC3MW = (1552+546)/3

INFLOWS:

OPRetire2 = OPIC2MW/OPIC_Delay/3

OUTFLOWS:

OPRetire3 = OPIC3MW/OPIC_Delay/3

OPICMW(t) = OPICMW(t - dt) + (OP_Online_Rate - OPRetire1) * dt

INIT OPICMW = (1552+546)/3

INFLOWS:

OP_Online_Rate = OPUNConsMW/OPUCDelay

OUTFLOWS:

OPRetire1 = OPICMW/OPIC_Delay/3

OPTotalCost(t) = OPTotalCost(t - dt) + (OPInstallCost + OPOperCost) * dt

INIT OPTotalCost = 0

INFLOWS:

OPInstallCost = OP_Installed*OPInsCostperMW

OPOperCost = GrsElecGenbyOilGWh*OPOperCostperGWh

OPUNConsMW(t) = OPUNConsMW(t - dt) + (OP_Installed - OP_Online_Rate) * dt

INIT OPUNConsMW = 0

INFLOWS:

OP_Installed = max(0,InstallOP_MW)

OUTFLOWS:

OP_Online_Rate = OPUNConsMW/OPUCDelay

CurOPNeedAllocGWh = IF TIME<1999 THEN (CurGrsElectGenAllocbyNationICGWh*OilCapFract_Initial) ELSE (CurGrsElectGenAllocbyNationICGWh*OilSmthCapFract)

DesiredUCOil = OPRetire3*OPUCDelay

DomGenbyOPGWh = min(GrsElecGenbyOilGWh,DomOilResPotenGWh)

DomOilResPotenGWh = YearlyMaxOilProd*OilPPConsRatio/OilUseperGWh/ProcessTime

EmisRelbyOP = GrsElecGenbyOilGWh*OilEmisTONperGWh

FutOPNeedAllocGWh = IF TIME<1999 THEN (FutNRENNeedGWh*OP_InstFractInitial) ELSE (FutNRENNeedGWh*OPSmthInstFract*Oil_Priority)

GrsElecGenbyOilGWh = MIN (TotOPICGWh,CurOPNeedAllocGWh)

InstallOP_MW = (NeedOP_MW-TotOPIC_MW)/AT1+(DesiredUCOil-OPUNConsMW)/AT2+OPRetire3

NeedOP_MW = FutOPNeedAllocGWh/OPAvailability/OPCapUtil/MaxWorkingHour*1000

OilCapFract_Initial = .068

OilEmisTONperGWh = 825

OilImportedTON = Max(0,(OilTotalUsedTON-YearlyOilDepTON))

OilProdFr = 0.05

OilResRateInTotal = TotalPotOilEnergyGWh/TotalNonRenReserveGWh

OilSmthCapFract = Oil_CapFract*TransEff+OilCapFract_Initial*(1-TransEff)

OilTotalUsedTON = GrsElecGenbyOilGWh*OilUseperGWh

OilUseperGWh = 277

Oil_CapFract = TotOPICGWh/TotGrsCapGWh

Oil_Priority = 1

OPAvailability = .60

OPCapUtil = 1

OPIC_Delay = 30

OPInsCostperMW = 2000000

OPOperCostperGWh = 0.06*1000000

OPSmthInstFract = OP_InstFract*TransEff+OP_InstFractInitial*(1-TransEff)

OPUCDelay = 4

OP_InstFract = .09

OP_InstFractInitial = 0

TotalPotOilEnergyGWh = CrudeOilReserveTON*OilPPConsRatio/OilUseperGWh/ProcessTime

TotOPICGWh = TotOPIC_MW*OPAvailability*OPCapUtil*MaxWorkingHour/1000

TotOPIC_MW = OPICMW+OPIC2MW+OPIC3MW

YearlyMaxOilProd = CrudeOilReserveTON*OilProdFr

OilPPConsRatio = GRAPH(time)

(1990, 0.05), (1991, 0.0532), (1992, 0.057), (1993, 0.066), (1994, 0.0795), (1995, 0.0907), (1996, 0.0968), (1997, 0.099), (1998, 0.1)

SMALL SCALED HYDROPOWER

SHPIC1_MW(t) = SHPIC1_MW(t - dt) + (SHP_Online_Rate - SHPRetire1) * dt

INIT SHPIC1_MW = 186.05/3

INFLOWS:

SHP_Online_Rate = SHPUC_MW/SHPUC_Delay

OUTFLOWS:
SHPRetire1 = SHPIC1_MW/(SHPIC_Delay/3)

SHPIC2_MW(t) = SHPIC2_MW(t - dt) + (SHPRetire1 - SHPRetire2) * dt

INIT SHPIC2_MW = 186.05/3

INFLOWS:

SHPRetire1 = SHPIC1_MW/(SHPIC_Delay/3)

OUTFLOWS:

SHPRetire2 = SHPIC2_MW/(SHPIC_Delay/3)

SHPIC3_MW(t) = SHPIC3_MW(t - dt) + (SHPRetire2 - SHPRetire3) * dt

INIT SHPIC3_MW = 186.05/3

INFLOWS:

SHPRetire2 = SHPIC2_MW/(SHPIC_Delay/3)

OUTFLOWS:

SHPRetire3 = SHPIC3_MW/(SHPIC_Delay/3)

SHPpotNotUsedGWhyear(t) = SHPpotNotUsedGWhyear(t - dt) + (SHP_Pot_Added - SHPotUsage) * dt

INIT SHPpotNotUsedGWhyear = 32900-3695

INFLOWS:

SHP_Pot_Added = SHPRetire3*SHPAvailability*SHPCapUtil*MaxWorkingHour

OUTFLOWS:

SHPotUsage = SHPInitiateGWh

SHPTotalCost(t) = SHPTotalCost(t - dt) + (SHPInstallCost + SHPOperCost) * dt

INIT SHPTotalCost = 0

INFLOWS:

SHPInstallCost = SHPInstalled*SHPInsCostperMW

SHPOperCost = GrsElectGenbySHPGWh*SHPOperCostperGWh

SHPUC_MW(t) = SHPUC_MW(t - dt) + (SHPInstalled - SHP_Online_Rate) * dt

INIT SHPUC_MW = 8.8

INFLOWS:

SHPInstalled = SHPotUsage/(SHPCapUtil*SHPAvailability*MaxWorkingHour)*1000

OUTFLOWS:

SHP_Online_Rate = SHPUC_MW/SHPUC_Delay

DesiredUC_SHP = SHPRetire3*SHPUC_Delay

EmisRelbySHP = GrsElectGenbySHPGWh*SHPEmisTONperGWh

FutSHPNeedAllocGWh = IF TIME<1999 THEN (SHPFracInitial*FutRENNeedGWh) ELSE
(FutRENNeedGWh*SHPSmthInsFrac)

GrsElectGenbySHPGWh = IF TIME<1999 THEN (CurGrsElectGenAllocbyNationICGWh*SHPCapFract_Initial) ELSE
(CurGrsElectGenAllocbyNationICGWh*SHPSmthCapFract)

InstallSHP_MW = (NeedSHP_MW-TotSHPIC_MW)/AT1+(DesiredUC_SHP-SHPUC_MW)/AT2+SHPRetire3

NeedSHP_MW = FutSHPNeedAllocGWh/SHPAvailability/SHPCapUtil/MaxWorkingHour*1000

SHPAvailability = 0.60

SHPcapFract = TotSHPICGWh/TotGrsCapGWh

SHPCapFract_Initial = .011

SHPCapUtil = 1

SHPEmisTONperGWh = 200

SHPFracInitial = .027

SHPIC_Delay = 45

SHPInitiateGWh =
MIN(MAX(0,(InstallSHP_MW*SHPAvailability*SHPCapUtil*MaxWorkingHour/1000)),SHPpotNotUsedGWhyear)

SHPInsCostperMW = 750000

SHPInstFractRevised = SHP_Inst_Frac/RENInstFracAdjust

SHPOperCostperGWh = 0.0005*1000000

SHPSmthCapFract = SHPcapFract*TransEff+SHPCapFract_Initial*(1-TransEff)

SHPSmthInsFrac = (SHPFracInitial*(1-TransEff))+(SHPInstFractRevised*TransEff)

SHPUC_Delay = 1

SHP_Inst_Frac = SHP_Poten_Rate*SHP_Priority

SHP_Poten_Rate = SHPpotNotUsedGWhyear/TotRENPotGWh

SHP_Priority = 1

TotSHPICGWh = TotSHPIC_MW*SHPAvailability*SHPCapUtil*MaxWorkingHour/1000

TotSHPIC_MW = SHPIC1_MW+SHPIC2_MW+SHPIC3_MW

SOLAR POWER

SPIC1_MW(t) = SPIC1_MW(t - dt) + (SP_Online_Rate - SPRetire1) * dt

INIT SPIC1_MW = 0

INFLOWS:

SP_Online_Rate = SPUC_MW/SPUC_Delay

OUTFLOWS:

SPRetire1 = SPIC1_MW/(SPIC_Delay/3)

SPIC2_MW(t) = SPIC2_MW(t - dt) + (SPRetire1 - SPRetire2) * dt

INIT SPIC2_MW = 0

INFLOWS:

SPRetire1 = SPIC1_MW/(SPIC_Delay/3)

OUTFLOWS:

SPRetire2 = SPIC2_MW/(SPIC_Delay/3)

SPIC3_MW(t) = SPIC3_MW(t - dt) + (SPRetire2 - SPRetire3) * dt

INIT SPIC3_MW = 0

INFLOWS:

SPRetire2 = SPIC2_MW/(SPIC_Delay/3)

OUTFLOWS:

SPRetire3 = SPIC3_MW/(SPIC_Delay/3)

SPTotalCost(t) = SPTotalCost(t - dt) + (SPInstallCost + SPOperCost) * dt

INIT SPTotalCost = 0

INFLOWS:

SPInstallCost = SPInstalled*SPInsCostperMW

SPOperCost = GrsElectGenbySPGWh*SPOperCostperGWh

SPUC_MW(t) = SPUC_MW(t - dt) + (SPInstalled - SP_Online_Rate) * dt

INIT SPUC_MW = 0

INFLOWS:

SPInstalled = SPotUsage/(SPAvailability*SPCapUtil*MaxWorkingHour)*1000

OUTFLOWS:

SP_Online_Rate = SPUC_MW/SPUC_Delay

SP_potNotUsedGWhYear(t) = SP_potNotUsedGWhYear(t - dt) + (SP_Pot_Added - SPotUsage) * dt

INIT SP_potNotUsedGWhYear = 80000000

INFLOWS:

SP_Pot_Added = SPRetire3*SPAvailability*SPCapUtil*MaxWorkingHour

OUTFLOWS:

SPotUsage = SPInitiateGWhyear

DesiredUC_SP = SPRetire3*SPUC_Delay

EmisRelbySP = GrsElectGenbySPGWh*SPEmisTONperGWh

FutSPNeedAllocGWhyear = IF TIME<1999 THEN (SPInstFracInitial*FutRENNeedGWh) ELSE
(FutRENNeedGWh*SPSmthInsFrac)

GrsElectGenbySPGWh = IF TIME<1999 THEN (CurGrsElectGenAllocbyNationICGWh*SPCapFract_Initial) ELSE
(CurGrsElectGenAllocbyNationICGWh*SPSmthCapFract)

InstallSP_MW = (NeedSP_MW-TotSPIC_MW)/AT1+(DesiredUC_SP-SPUC_MW)/AT2+SPRetire3

NeedSP_MW = FutSPNeedAllocGWhyear/SPAvailability/SPCapUtil/MaxWorkingHour*1000

SPAvailability = .30

SPcapFrac = TotSPICGWh/TotGrsCapGWh

SPCapFract_Initial = 0

SPCapUtil = 1

SPEmisTONperGWh = 175

SPIC_Delay = 25

SPInitiateGWhyear =
MIN(MAX(0,(InstallSP_MW*SPAvailability*SPCapUtil*MaxWorkingHour/1000)),SP_potNotUsedGWhYear)

SPInsCostperMW = 6000000

SPInstFrac = SP_Poten_Rate*SP_Priority

SPInstFracInitial = 0

SPInstFractRevised = SPInstFrac/RENInstFracAdjust
SPOperCostperGWh = 0.20*1000000

SPSmthCapFract = SPcapFrac*TransEff+SPCapFract_Initial*(1-TransEff)

SPSmthInsFrac = (SPInstFracInitial*(1-TransEff))+(SPInstFractRevised*TransEff)

SPUC_Delay = 1

SP_Poten_Rate = SP_potNotUsedGWhYear/TotRENPotGWh

SP_Priority = 1

TotSPICGWh = TotSPIC_MW*SPAvailability*SPCapUtil*MaxWorkingHour/1000

TotSPIC_MW = SPIC1_MW+SPIC2_MW+SPIC3_MW

WIND POWER

WPIC1_MW(t) = WPIC1_MW(t - dt) + (WP_Online_Rate - WPRetire1) * dt

INIT WPIC1_MW = 0

INFLOWS:

WP_Online_Rate = WPUC_MW/WPUC_Delay

OUTFLOWS:

WPRetire1 = WPIC1_MW/(WPIC_Delay/3)

WPIC2_MW(t) = WPIC2_MW(t - dt) + (WPRetire1 - WPRetire2) * dt

INIT WPIC2_MW = 0

INFLOWS:

WPRetire1 = WPIC1_MW/(WPIC_Delay/3)

OUTFLOWS:

WPRetire2 = WPIC2_MW/(WPIC_Delay/3)

WPIC3_MW(t) = WPIC3_MW(t - dt) + (WPRetire2 - WPRetire3) * dt

INIT WPIC3_MW = 0

INFLOWS:

WPRetire2 = WPIC2_MW/(WPIC_Delay/3)

OUTFLOWS:

WPRetire3 = WPIC3_MW/(WPIC_Delay/3)

WPpotNotUsedGWhYear(t) = WPpotNotUsedGWhYear(t - dt) + (WP_Pot_Added - WPotUsage) * dt

INIT WPpotNotUsedGWhYear = (400000+180000)

INFLOWS:

WP_Pot_Added = WPRetire3*WPAvailability*WPCapUtil*MaxWorkingHour

OUTFLOWS:

WPotUsage = WPInitiateGWh

WPTotalCost(t) = WPTotalCost(t - dt) + (WPInstallCost + WPOperCost) * dt

INIT WPTotalCost = 0

INFLOWS:

WPInstallCost = WPInstalled*WPInsCostperMW

WPOperCost = GrsElectGebyWPGWh*WPOperCostperGWh

WPUC_MW(t) = WPUC_MW(t - dt) + (WPInstalled - WP_Online_Rate) * dt

INIT WPUC_MW = 0

INFLOWS:

WPInstalled = WPotUsage/(WPAvailability*WPCapUtil*MaxWorkingHour)*1000

OUTFLOWS:

WP_Online_Rate = WPUC_MW/WPUC_Delay

DesiredUC_WP = WPRetire3*WPUC_Delay

EmisRelbyWP = GrsElectGebyWPGWh*WPEmisTONperGWh

FutWPNeedAllocGWh = IF TIME<1999 THEN (WPFracInitial*FutRENNeedGWh) ELSE (FutRENNeedGWh*WPSmthInsFrac)

GrsElectGebyWPGWh = IF TIME<1999 THEN (CurGrsElectGenAllocbyNationICGWh*WPCapFract_Initial) ELSE (CurGrsElectGenAllocbyNationICGWh*WPSmthCapFract)

InstallWP_MW = (NeedWP_MW-TotWPIC_MW)/AT1+(DesiredUC_WP-WPUC_MW)/AT2+WPRetire3

NeedWP_MW = FutWPNeedAllocGWh/WPAvailability/WPCapUtil/MaxWorkingHour*1000

TotWPICGWh = TotWPIC_MW*WPAvailability*WPCapUtil*MaxWorkingHour/1000

TotWPIC_MW = WPIC1_MW+WPIC2_MW+WPIC3_MW

WPAvailability = 0.30

WPcapFrac = TotWPICGWh/TotGrsCapGWh

WPCapFract_Initial = 0

WPCapUtil = 1

WPEmisTONperGWh = 75

WPFracInitial = 0

WPIC_Delay = 25

WPInitiateGWh =
MIN(MAX(0,(InstallWP_MW*WPAvailability*WPCapUtil*MaxWorkingHour/1000)),WPpotNotUsedGWhYear)

WPInsCostperMW = 1450000

WPInstFrac = WP_Poten_Rate*WP_Priority

WPInstFractRevised = WPInstFrac/RENInstFracAdjust

WPOperCostperGWh = 0.045*1000000

WPSmthCapFract = WPcapFrac*TransEff+WPCapFract_Initial*(1-TransEff)

WPSmthInsFrac = (WPFracInitial*(1-TransEff))+(WPInstFractRevised*TransEff)

WPUC_Delay = 1

WP_Poten_Rate = WPpotNotUsedGWhYear/TotRENPotGWh

WP_Priority = 1