Dynamics of CO_2 Mitigation in Electric Power Industry through Replacements and Early Retirements

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Abstract

As the second commitment period of the Kyoto Protocol ends by year 2012, the long term national greenhouse gas (GHG) abatement targets that individual countries will assume stay ambiguous but the imperative of dramatic reductions over the 21st century is virtually certain. At the global scale, electric power (EP) industry accounts for 26% of global GHG emissions. Because, electric power production has the largest share in GHG production among other sectors of the economy, and because there are many alternative ways of producing electric power from renewable and non renewable resources other than fossil fuels, EP industry is expected to play a central role in climate change mitigation in many countries. With its rich clean energy potential, Turkey is a particular example. Being a developing economy, Turkey contributes to about one percent of global GHG emissions, and its per capita emissions are equal to and now exceeding the world average. The EP industry in Turkey is responsible for 28% of the national CO_2 emissions. If a viable and sustainable global climate treaty develops in the near future, as a party to the UNFCCC, Turkey will have to assume national abatement targets and face the challenge of shifting its heavily fossil fuel based EP production towards renewable energy sources (RES), decentralized generation (DG) and increasing efficiency gains. In this paper, we create a dynamic simulation model of EP industry in Turkey so as to analyze the options for CO_2 mitigation through replacements with clean energy resources and early retirements in fossil fuel based power generation. The model focuses on the supply side of EP sector and represents the investment, production, pricing and financing structures of coal, gas, hydro, wind and solar power plants as well as the existing natural potential for the renewable resources of wind and hydro. Decisions are formulated on annual basis and the model creates foresight for the next twenty years' developments in EP industry subject to alternative policies designed for CO_2 mitigation.

Keywords: electric power industry, CO_2 mitigation, renewable resources, replacements, early retirements.

I. INTRODUCTION

Electric power (EP) production accounts for 28% of Turkey's national CO_2 emissions (Apak and Ubay 2007). Between 1990 and 2004, overall primary energy consumption in Turkey grew by 3.7% per year, while its total GHG emissions has increased by about 3.5% per year, from 132 to 227 Mt-CO_2 equivalent. With regard to CO_2 emissions alone, the share of EP industry among other primary energy uses (industry, transportation and others) has increased from 27 to 34%, and it reached from 35 to 75 Mt-CO_2 (5% annual increase). The dramatic increase in CO_2 emissions from EP industry is due to a strong shift from hydropower towards fossil fuel based production, particularly to gas fired power plants.

After decades of state monopoly on generation, transmission and distribution of electricity, Turkish EP sector first became open to private participation in year 1984 (law 3096) (Hepbaşlı 2005). However, first private investments started by year 1996. Typical build-operate-transfer (BOT), build-operate-own (BOO) or transfer of operating rights (TOR) agreements involved "take or pay" generation contracts with fixed quantities and prices over 15-30 years (Atiyas and Dutz 2003).

In 2001, the Electricity Market Law (EML) provided a new and radically different framework for the design of the electricity market (Atiyas and Dutz 2003). The law was designed to establish a competitive electricity market to promote private participation and to improve efficiency in generation and distribution. According to the EML law, generation, wholesale, transmission and distribution activities of the electricity sector were unbundled. Competition was introduced into the generation and retail sale stages. In order to assure transparency and independent regulation over the sector, an autonomous Energy Market Regulatory Authority (EMRA) was established. In order to ensure a competitive environment, transmission and distribution companies were required to allow open access to their networks for third parties. According to EML, the national transmission grid would be held as state property under control of Turkish Electricity Transmission Company (TEİAŞ) (Özkıvrak 2005).

By year 2008, Turkey's total generation capacity was 41,817 MW. This capacity is composed of a mix of state owned generation plants (EÜAŞ), BOT-BOO-TOR plants, private plants and auto-producers. Relevant figures are presented in Table 1.

Table 1. Installed capacity in Turkish EP industry, 2008 (TEİAŞ 2009).

Company	**MW**	**Share (%)**
EÜAŞ	23,981	57.3
BOT-BOO-TOR	9,464	22.6
Private	4,840	11.6
Auto-producer	3,533	8.5
Total	41,818	100

In total installed capacity, hard coal and imported coal fired power plants comprise 24%, gas 36%, large hydro power 32%, small hydropower 1.06%, wind 0.87%, solar and geothermal

0.07% and others (including oil and traditional biomass) 5.6% (EÜAŞ 2008). In year 2008, total electricity production reached 198,418 GWh with an increase of 3.5% with respect to the previous year. Total electricity consumption grew to 198,085 with a 4.2% annual increase (EÜAŞ 2008).

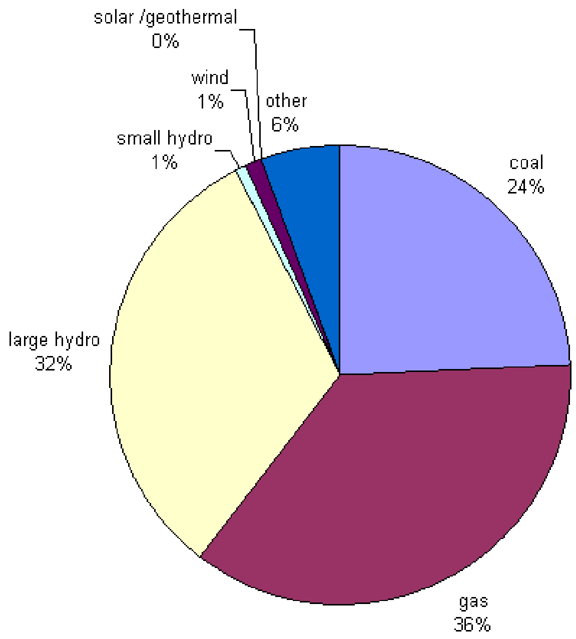

Figure 1. Installed Capacity Shares, 2008.

Electricity generation in Turkey is mainly based on thermal plants. As of 2008, their share in total energy production is 82.7 %. while hydro and wind power plants have 16.7% and 0.4% shares respectively (EÜAŞ 2008). Natural gas fired power plants are the largest single source of generation with 48.4% share in total production. Lignite and hard coal fired power plants have the second share (22.7%) and hydro power plants comes third (16.7%). 49.3% of total production is provided by EÜAŞ (through 104 hydro and 19 thermal power plants). In 2008, Turkey exported 1.222 GWh electricity while importing 789 GWh (TEİAŞ 2009). These figures are summarized in Figure 2.

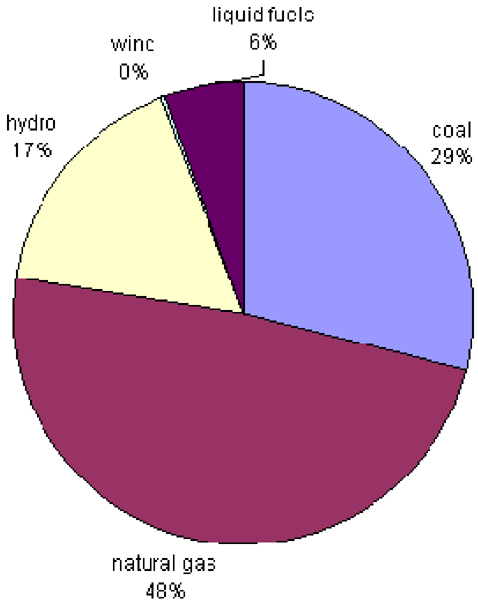

Figure 2. Resource Share in EP Generation, 2008.

Turkey is rich in its renewable energy potential but it is not sufficiently exploited for electricity generation. The economic renewable resource potentials and their respective utilization rates in 2008 is presented in Table 2.

Resources	**Installed Capacity (MW)**	**Economic Potential (MW)**	**Percent Utilized (%)**
Hydropower (large)	13390	32000 MW	42
Hydropower (small)< 10 MW	438	20140	2
Wind (terrestrial)	364	16352 MW	2.3
Solar /Geothermal	30	140000 MW	0.02

Table 2. Turkey's Renewable Energy Resource Potentials (TÜSİAD 1998).

The economic potentials presented in Table 2 needs to be considered with caution. Calculated economic potentials assume that the revenues from energy generation will be larger than its costs. However these calculations can be overestimated since the environmental and social costs of many potential renewable energy projects are underestimated. Large and small hydropower projects are the prominent example.

II. PROBLEM

Turkey has become a party to the Kyoto protocol but not declared its GHG abatement targets yet. In the absence of a binding international treaty, Turkey has not yet initiated appropriate regulations and incentives to reduce its GHG emissions generated by the EP industry. On the other hand, if a binding international treaty develops in the near future, Turkey will assume national targets and the fossil fuel dominated structure of the EP industry will become a primary matter of concern for the policy makers. To design appropriate GHG control policies, an understanding of the environmental and economic impacts of several abatement programs will become particularly important. Possible abatement programs are composed of regulatory (ex. investment subsidies, fixed payments), quantity driven (ex. green certificates) and indirect strategies (ex. carbon taxes and emission allowances) (Haas, Meyer et al. 2008).

The purpose of this paper is to analyze the new capacity investments and generation in the national EP industry and early retirements particularly in coal fired power plants under particular CO_2 abatement programs. The focus is on the generation and wholesales side. For this purpose, a dynamic simulation model is developed. The model represents investment, production and pricing decisions in coal and gas fired plants, in large and small-scale hydro as well as in wind power plants. Decisions are represented in annual basis and the model is simulated to observe the next twenty years of the EP sector in terms of CO_2 emissions and abatement costs. Effect of regulated and free market dispatch of EP, fast and slow licensing of renewable energy resources (RES), strong and weak constraints on decentralized generation (DG) connection to grid, carbon taxes, investment subsidies and fixed payments on future emissions are tested.

III. MODEL DESCRIPTION

The model consists of six sectors that represent different aspects of electricity generation. *Investment* sector represents the investment heuristics, capacity supply lines and the installed capacities of coal, gas, large and small hydro, wind and solar power plants. Actual and forecasted electricity demands, electricity price, possible sales of alternative generation types, return on investments, availability of financial resources and available permits are the fundamental inputs for investment decisions in this sector (see Figure 3).

Price and demand sector is the second model component. Electricity price based on two alternatives, regulated and on real time pricing of electricity, demand and demand forecasts are created in this sector. Interest rates, and maximum power generation rates are the inputs used by this model component.

Demand allocation sector allocates the actual and forecasted demand onto different types of power generation plants. Marginal costs of alternative production, forecasted demand and forecasted price, the availability of licenses for renewable energy resources (RES), and energy generation of RES (so as to calculate the grid connection constraints of DG are the inputs for this model component.

Power generation and emissions are created in the *generation and emissions* sector. Power plant installed capacities, marginal production costs, wholesale electricity price and power sales are the inputs used by this model component.

Model takes into account the natural resource base of RES in *natural resources* sector. Capital depreciation and construction rates of RES are the inputs for this sector.

Finally, the financial situations for each power plant type are represented in the *power plants finance* sector. Wholesale electricity price, electricity sales, power plant capacities and respective depreciation rates are the inputs to this model sector.

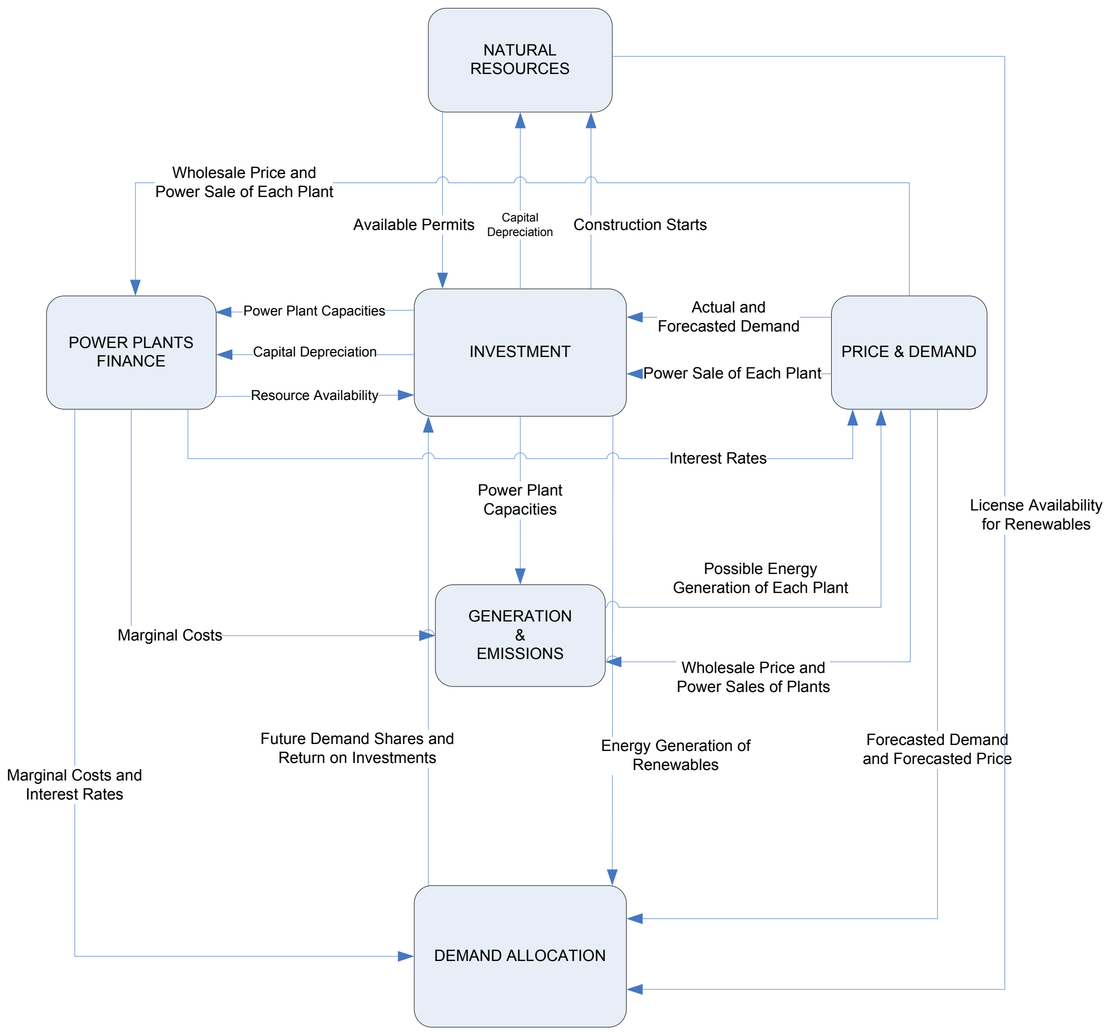

Figure 3. Model overview diagram.

III.1. Investment

Each plant type is represented with a third order construction delay and a third order depreciation delay. In addition, delay on site bank is incorporated into the supply line structure, which altogether creates a seventh order delay from applications for new capacity to depreciation of the existing capital (Ford 2001). Figure 4 depicts the simplified stock-flow structure.

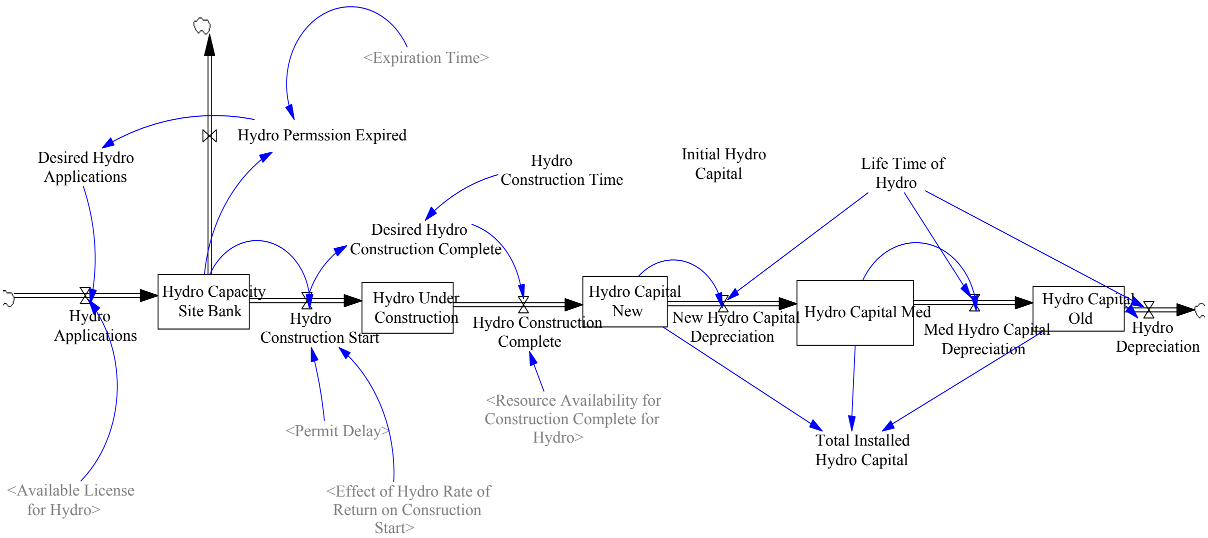

Figure 4. Investment Structure.

The license applications aim to close the gap between current and desired capacities now and in the future (Sterman 2000). Investors forecast future demand. Then they aim at compensating for the capacity depreciation and adjust for the actual, capital supply line and forecasted capacity gaps. A similar approach to utility investor behavior is used in (Kim, Ahn et al. 2007).

For the RES (large and small hydro, wind and solar), new capacity applications is a function of desired applications and availability of new licenses. It is assumed that, the regulator issues licenses available each year and the applications cannot exceed this amount. That is, if there is more than one application for a specific site, only one of them is accepted and the others are eliminated.

After applications, investors start power plant constructions according to their future profit expectations, represented by marginal rate of return on investment. For the effect return on construction start, the non-linear function in Figure 5 is used. As the marginal rate of return for an investment option approaches to zero, the investors become reluctant for power plant construction starts.

Figure 5. Effect of rate of return on construction starts.

Licenses not utilized within two years expire. That is, private investors wait until they foresee the whole sale price sufficient to create a positive return on investment.

Constructions finishing is influenced by the availability of financial resources. Constructions cannot continue if the liquid assets in the balance sheet are not sufficient.

III.2. Generation and Emissions

Technical capacity factors for individual power plants set an upper limit for the annual energy generation. The capacity factor can be interpreted as the percent of time that the power plant generates electricity at its nameplate capacity (Randolph 2008). Plant operators evade power generation if the revenue from electricity sales does not cover their marginal costs (Ford 1999). Since the power plants represented in the model structure aggregates similar power plants in the national sector, the effect of profitability on power generation of individual plant types is modeled with a nonlinear function (Equation 1):

profitability=electricity price/marginal costs Eq. 1.1.

average profitability=SMOOTH(profitability, averaging time) Eq. 1.2.

profit effect power gen=f(average profitability), $0<f<1$, $f(1)=0.98$, $f'>0$ Eq. 1.3.

power generation=capacity*cap factor*hours/year*profit effect power gen Eq. 1.4.

III.3. Price and Demand

In this sector; price bid and power sale of each plant type, wholesale price of electricity, actual and forecasted demands are calculated. Electricity market in Turkey is in a transition to real time pricing. In order to analyze the effects of this transition on electricity generation sector, we model two pricing mechanisms: First mechanism assumes that the electricity is purchased from each generator at a price equal its levelized cost. Profit margin for each plant type is included in the discount factor variable that is used for levelized cost calculation. In order to dispatch actual demand, the legislator company TEİAŞ sorts all existing electricity prices and begins to allocate the demand, starting from the provider with the least price.

In the second mechanism, generators bid their prices for certain time intervals in a day. In this system, supplied amounts are ordered according to their price bids (Figure 6). In this figure, p_i

is the price bid and q_i is the supplied amount from plant *i*. The model calculates annual wholesale price by linking the mid-points of supplied electricity values (q_i) with straight lines. *P'* is assumed to be the indicated annual wholesale price in the electricity markets for wholesale demand *D'*. The calculated price from this algorithm is smoothed with a stock, named Wholesale Price. The initial value of this stock is calculated from the wholesale price at year 2003 (EMRA 2003).

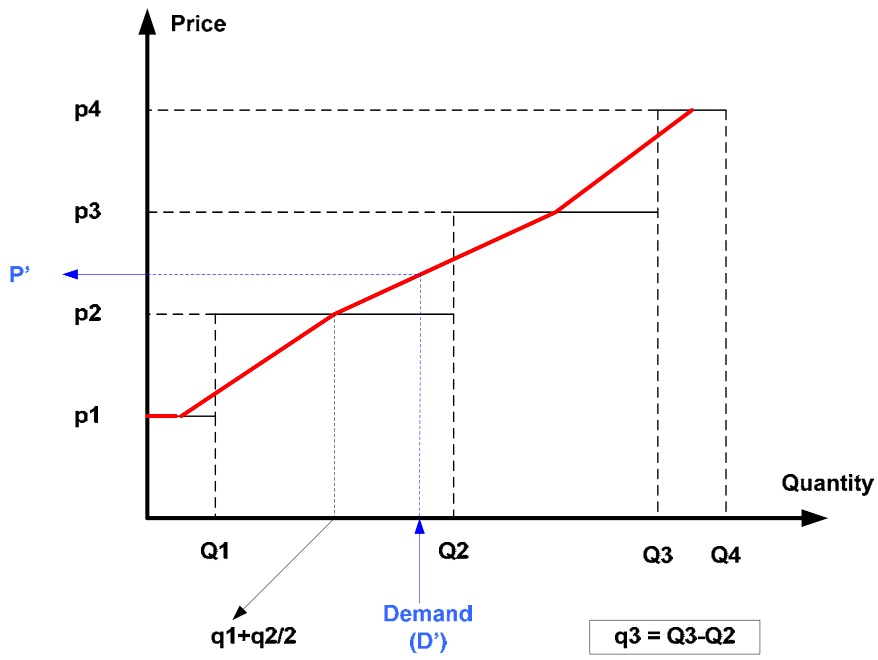

Figure 6. Electricity dispatch in real time pricing.

In the system based on contracting, electricity bids are assumed to be equal to levelized cost of each plant type however in real time pricing, the electricity bids of each plant converges to their marginal cost (Stoft 2002) under the market efficiency conditions.

It is assumed that, retail electricity demand is affected by the wholesale electricity price, such that profit margins of transmission and distribution companies are assumed to be constant.

In the base run, the growth fraction of retail demand is assumed to remain constant. Retail demand influenced by electricity price is converted to wholesale demand with the transmission efficiency constant, taken as 0.85 (TEİAŞ 2008). Wholesale demand is used to calculate the wholesale price as depicted in Figure 6.

In this sector, wholesale demand is used for the calculation of forecasted demand in the following way: The trend in wholesale demand is estimated by Vensim TREND function (Ventana 1988-2008). This algorithm estimates the annual growth rate of the demand using a three-stock structure (Sterman 2000), p. 635). Then the estimated trend is used for demand forecasting with the formula in (Sterman 2000), p. 640.). Forecasting horizon is set to 6 years for all generation technologies.

III.4. Power Plants Finance

This sector consists of two stocks representing liquid assets and debt of each power plant type which are fundamental components of a balance sheet describing the financial condition of a business company (Figure 7). Furthermore, income statements that illustrate annual costs, revenues and taxes of each plant type are calculated. This structure is similar to the system model in (Lyneis 1980).

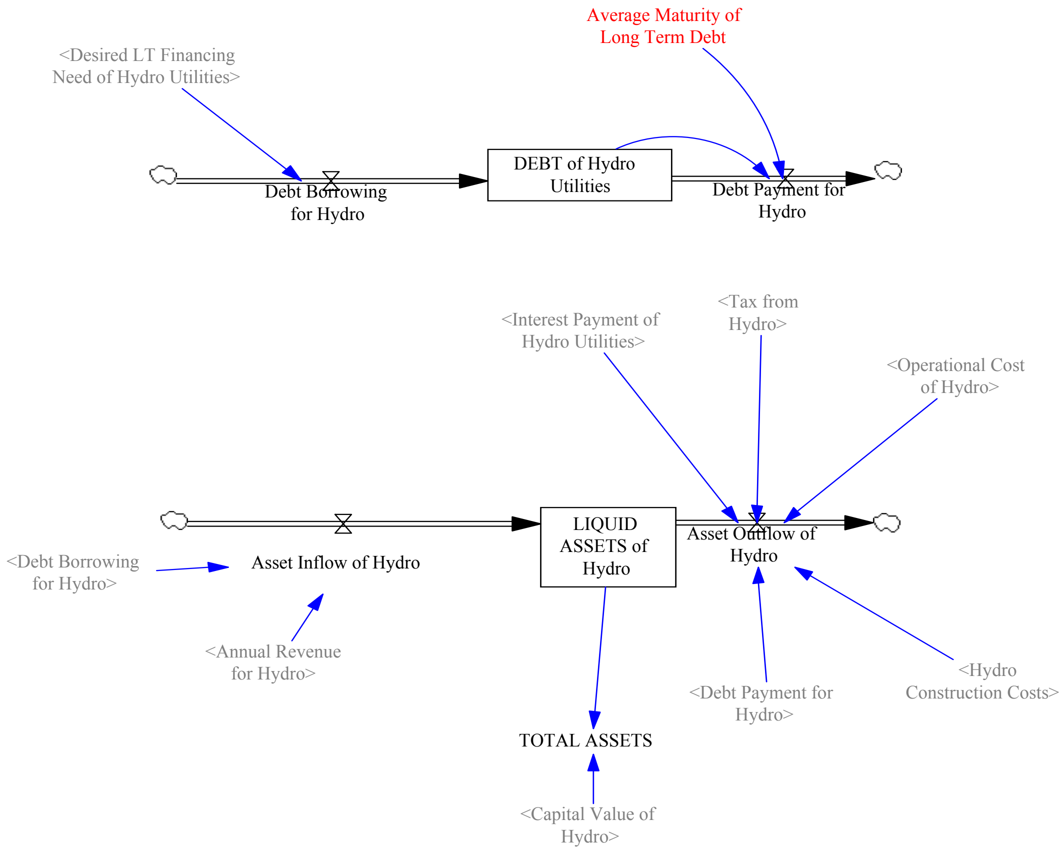

Figure 7. Power plants finance structure.

There are two major options for business firms in order to finance an investment project. These options, named debt and equity financing, have both advantages and disadvantages. Usually the financial managers seek to reach an optimum combination of these two in order to finance the investment in the most appropriate way. Furthermore it is also possible that financial managers may prefer to use only debt issuing. In this model, for the sake of simplicity we assume that the investment projects in electricity market of Turkey is financed only with debt issuing.

For determining the amount of debt to be taken, desired financing need is calculated within this sector. Desired debt financing is equal to required financing for investment plus expected debt payment minus internal net cash flow (Qureshi 2004). Debt payment of a power plant is affected by the financial situation of the company. If the financial measures of a company are not good, financing of an investment project is more difficult and more expensive. This causal relation is represented through interest coverage ratio in this model.

Interest coverage can be defined as the ratio of interest expenses to earnings before interest and taxes (EBIT). This measure indicates the ability of a business company for covering the interest expenses with its revenue. Interest coverage ratio affects interest rate and debt borrowing.

As explained above, the cost of debt issuing increases as interest coverage ratio approaches to 1. Interest rate of an issued debt consists of three components, named risk free interest rate, risk premium and inflation rate. Risk free interest rate is determined by the market conditions and it is independent of the company's financial situation. Inflation is set to zero, since price data for calibration is free from inflation. Therefore, the effect of interest coverage on cost of debt is modeled through risk premium rate. Risk premium of interest rate approaches 6% as interest expenses goes to the twice of EBIT. The effect of interest coverage on cost of debt is modeled with the table function given in Figure 8.

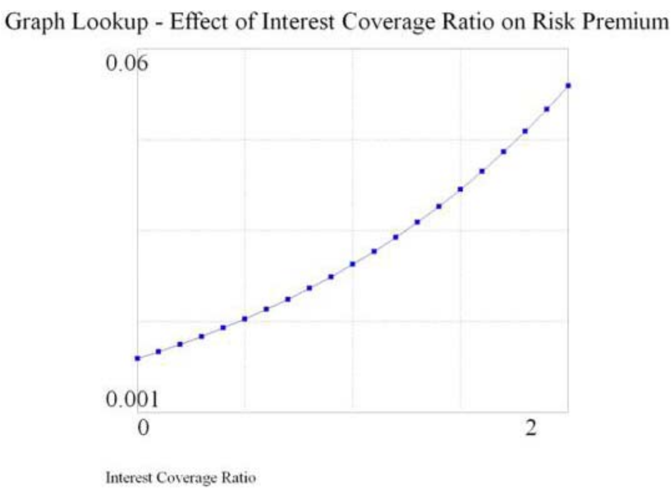

Figure 8. Effect of interest coverage on cost of debt.

If a company cannot make money without its sales, it cannot finance the new projects with external financing. Bad financial measures not only yield high-cost debt but it also creates shortage of financial resources since the investors in financial market do not want to borrow money. This effect of interest coverage ratio on debt borrowing is modeled with the table function given in Figure 8. In this function we assumed that the availability of debt issuing converges to zero as interest coverage approaches 3.

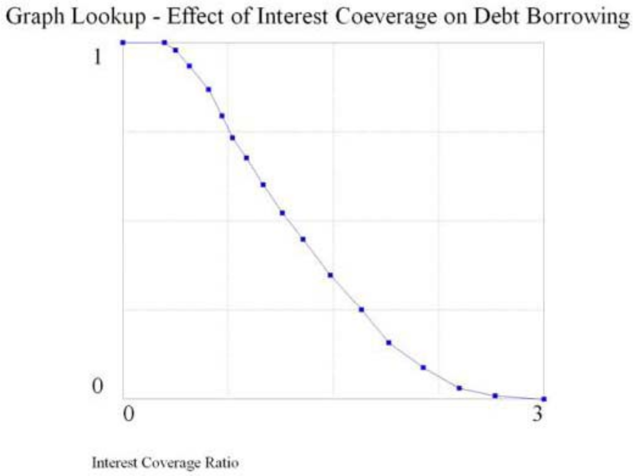

Figure 8. Effect of interest coverage ratio on debt borrowing.

Liquid asset is the essential part of the sector representing the aggregation of liquid assets and accounts receivable parts of the balance sheet. Inflows of liquid assets are debt borrowing and annual revenue whereas debt payments, costs and taxes constitute the outflow. Debt payment is the outflow of debt stock which is described above.

Costs of a power generation company can be aggregated under three different groups. These are operations and maintenance, overnight construction and fuel costs. All these costs are taken from 2005 update of International Energy Agency document, named Projected Cost of Generating Electricity (NEA and IEA 2005). Overnight construction cost is defined as the amount of money an investment requires if the whole construction is completed at one night.

Operations and maintenance cost can be separated into fixed and variable components. However, we assumed that all operations and maintenance costs are incurred whether electricity generation occurs or not. On the other hand, fuel cost of power plants remain zero if there is no electricity generation. Cost parameters are presented in Table 3.

	OVERNIGHT CONSTRUCTION COSTS($/KW)	O&M COSTS($/KW)	FUEL COST ($/KWh)	CAPACITY FACTOR
COAL	1250	30	9.71	0.85
NATURAL GAS	500	5540	16.81	0.8
LARGE HYDRO	1600	3	0	0.45
SMALL HYDRO	1602	19.52	0	0.5
WIND	1500	25	0	0.25
SOLAR	3000	50	0	0.25

Table 3. Power plant cost parameters.

The liquid asset of a plant is a good indicator of its financial performance. In this model, the availability of liquid asset affects the construction completions in the investment sector through resource availability ratio. This ratio is equal to cash surplus after debt payment over cost of desired construction and it affects the construction complete flow in investment sector.

III. 5. Demand Allocation

In this model sector, future demand shares are calculated with respect to the attractiveness of each plant type.

There are three factors that affect the investment attractiveness of a particular type of power plant. These are decentralized generation ratio (indicating the available transmission capacity that can accommodate DG), natural resource availability (indicating the available natural resources granted site licenses) and marginal rate of return on investment. These variables are illustrated in Figure 9.

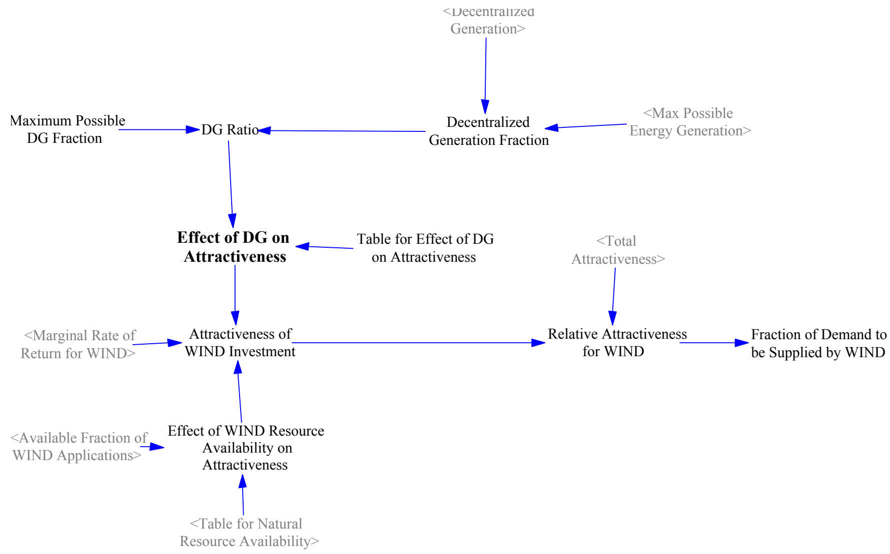

Figure 9. The investment attractiveness of power plants.

Marginal rate of returns are calculated by using costs, forecasted price and discounting factor. Marginal rate of return is multiplied with *Effect of Resource Availability* and *Effect of DG on Attractiveness* to calculate the investment attractiveness of an individual power plant type.

The effect of natural resource availability is represented with the graphical function in Figure 10. As available natural resources decreases, the function approaches zero and the power plant becomes less attractive.

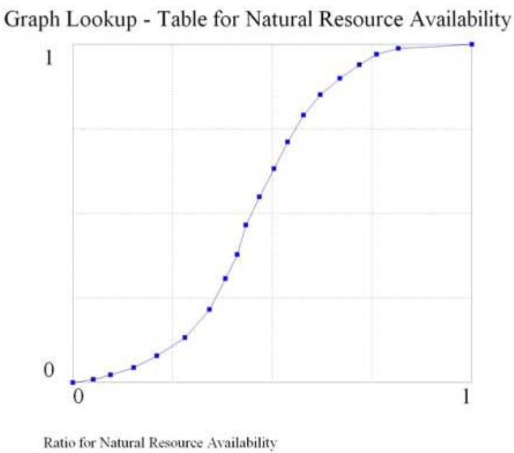

Figure 10. Effect of natural resource availability on investment attractiveness.

Other effect on attractiveness variable comes from decentralized generation constraint. Total generation of decentralized generation plants, such as wind, small hydro and solar, cannot exceed a specific percent of total generation transmitted on a grid. In order to consider the effect of this technical limit on the investment decision heuristic, the following nonlinear graphical function is used (Figure 11). As decentralized generation fraction approaches to maximum possible decentralized generation fraction, the function approaches to zero.

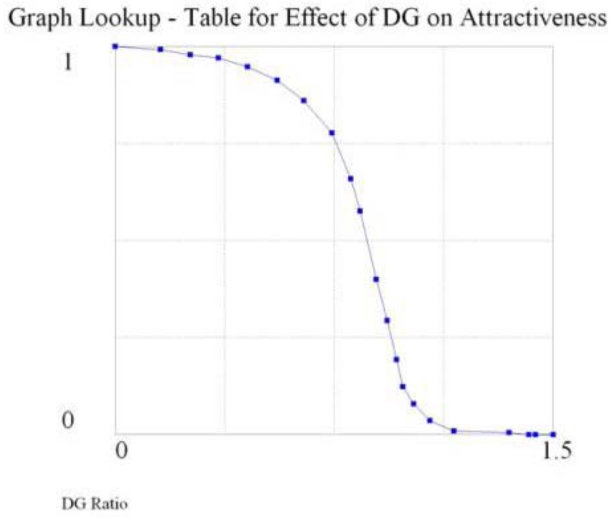

Figure 11. Effect of DG ratio on investment attractiveness.

The multiplication of these three components constitutes the attractiveness of each plant type. In order to calculate the shares of future demand, first order smoothing is applied to relative attractiveness for each plant type.

III. 6. Natural Resources

The unexploited economic potential for hydropower and wind are represented as stocks in units of MW. These stocks decreases by issued licenses and increases as licenses are expired or installed capacities are depreciated (Figure 12).

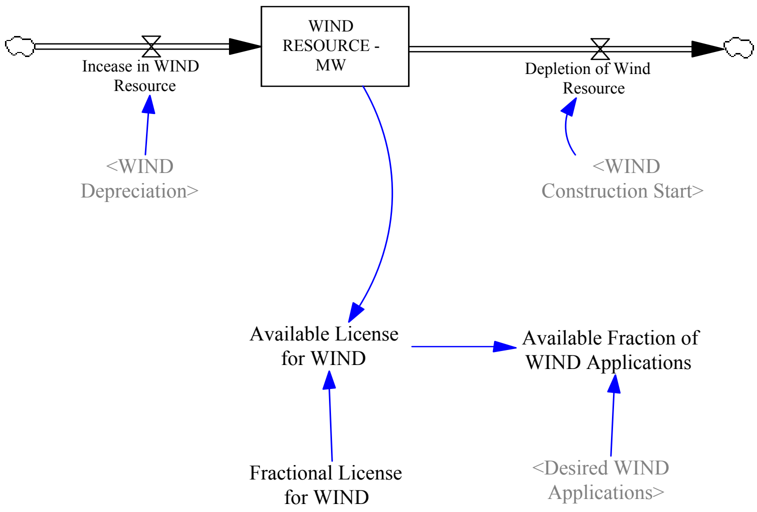

Figure 12. RES increase and depletion.

Available license for each renewable plant type is calculated in this sector. Fractional license in Figure 12 is the policy variable representing rate of license issuing for RES for power plant construction.

IV. MODEL BASE RUN

Model base run assumes, purchase guarantees for gas and RES (except large hydropower plants) until year 2015 and operates under the assumption that generators are able to sell the electricity that they produce at their levelized costs. Accordingly, in case of under-demand, the industries with the highest levelized costs have to reduce their production below its maximum as identified with respect to the capacity factor of that specific technology.

Figure 13 illustrates retail demand and growth in emissions in the base run with respect to data available for the historical period, 2000-2008. Figure 14 illustrates total installed capacity, renewable share in total installed capacity, total wholesale power generation and renewable share in power generation with respect to historical data. Total installed capacity and power generation grows by about 500% while the share of RES in capacity and generation are reduced by about 25% and 15% respectively.

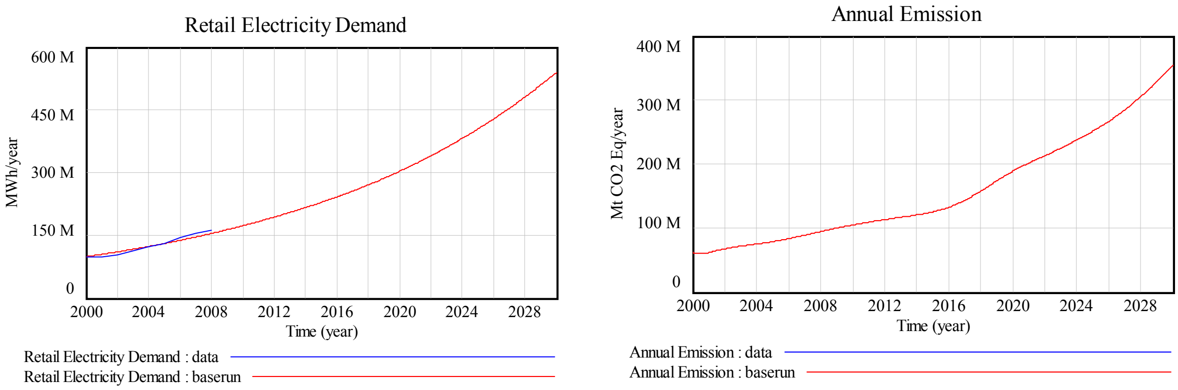

Figure 13. Retail Demand and Emissions, Base Run.

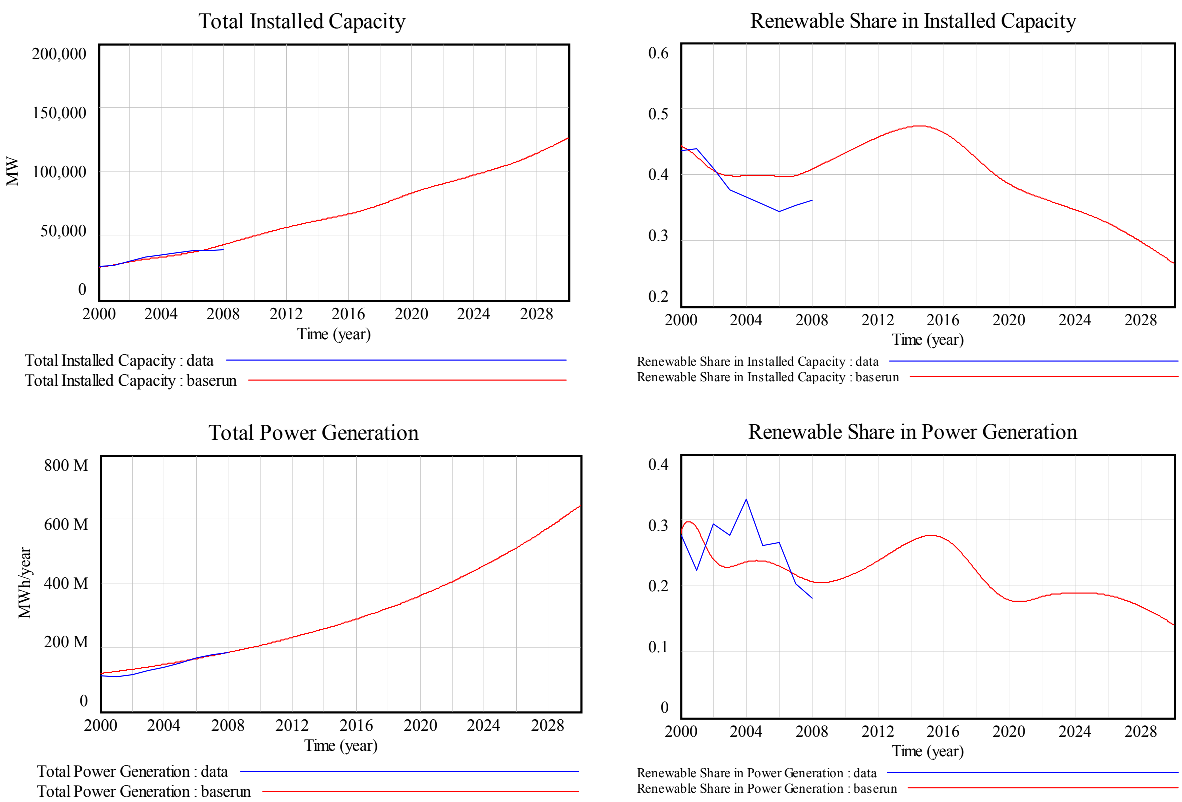

Figure 14. Capacities and Generations, Base Run.

V. SCENARIO AND POLICY ANALYSIS

The sections below summarize the significant changes in model output behavior, as alternative scenarios and policies are integrated one by one, so as to mitigate the inevitable growth in CO_2 emissions by the EP industry given the fact that the background retail demand grows at about 6% per year over the thirty years time horizon.

V.1. Market Transition

Market transition scenario assumes purchase guarantees for gas and renewables are lifted and there is a smooth transition towards real time pricing of EP in the electricity market as envisioned in the Electricity Market Law, 2001. Accordingly, the generators enter into dispatch with the order of increasing marginal costs multiplied with a certain markup so as to recover their investment and fixed costs..This significantly alters the order of dispatch to the advantage of generators with lower marginal production costs (i.e. hydropower and wind).

Figure 15 illustrates the renewable share in power generation and annual emissions under this scenario. While there is a sudden increase in EP production by RES by year 2016, there is corresponding sharp decline in emissions at the same year.

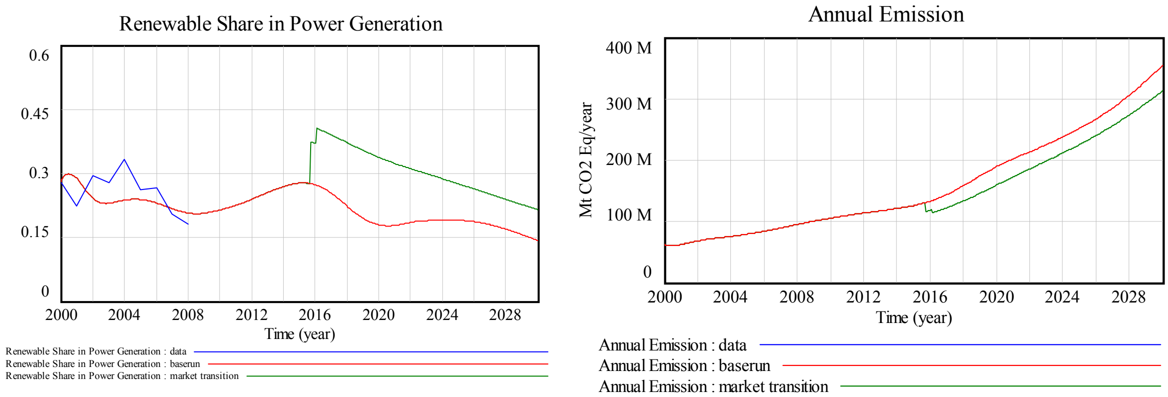

Figure 15. RES Share in Power Generation and Annual Emissions, Market Transition.

V.2. Lifting the Technical Constraints Against RES and DG

Second scenario assumes several improvements in systems performance to the advantage of RES and DG. Accordingly, the percentage of DG generation allowed to be accommodated on transmission lines is increased from 10 to 20. Available licenses for hydro and wind resources are increased. Moreover, the overall industry starts operating with a lower desired reserve margin (reduced from 0.4 to 0.2) and transmission losses on grid lines are reduced from 16% to 10% all to the advantage of reduced carbon emissions.

Figure 16 illustrates the model output behaviors for RES capacity and generation shares and annual emissions. While there is a significant increase in RES share in capacity and generations, annual emissions are reduced by about 30% in year 2030 with respect to the base run (the business as usual scenario).

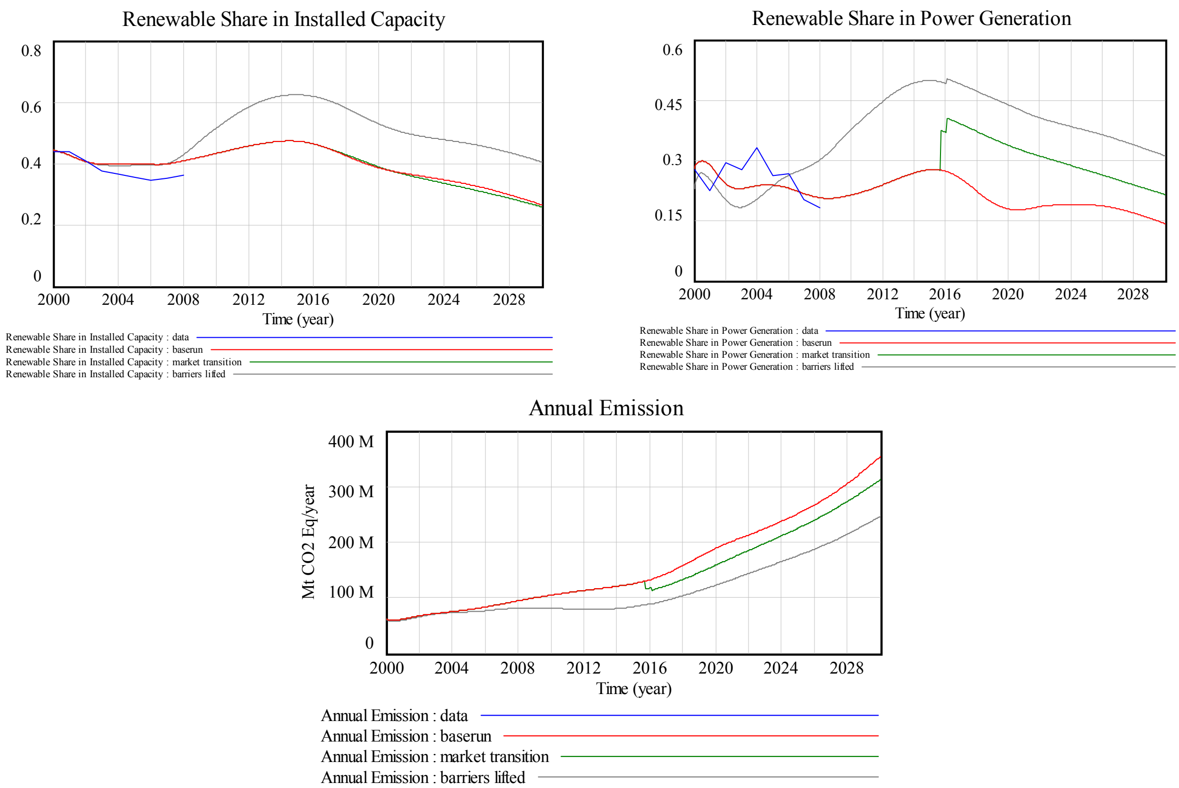

Figure 16. RES Capacity and Generation Shares and Annual Emissions, Technical Constraints Lifted.

V.3. Carbon Policies

In this section, several carbon abatement programs are introduced. First carbon tax is introduced for coal and gas fired power plants (1 and 0.5 dolar cents/KWh respectively). Renewable energy resources except the large hydro plants are subsidized by reduced interest rates (2% less than the risk free interest rate) and reduced taxes (20% tax instead of 40% on annual profit before tax). Moreover, there are direct investment subsidies for small hydropower, wind and solar power plants (of 0.3 M dollars/MW capacity).

Figure 17 summarizes the results when these policies are integrated with the above scenario. Although there is marginal improvement in terms of RES shares and emissions, the leverage is not as high as the previous scenarios. This is because the RES except hydropower is still too costly to compete with its conventional alternatives.

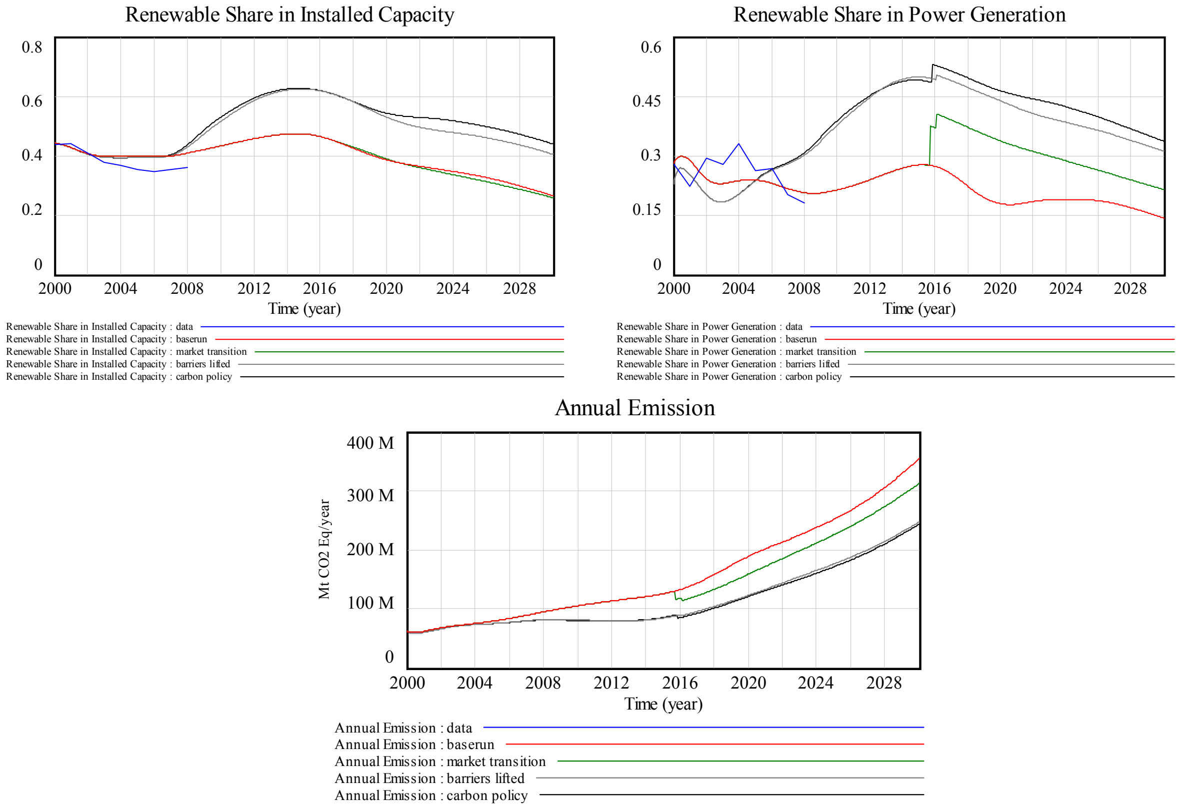

Figure 17. RES Shares and Emissions, Carbon Policies.

V.4. Nuclear Power Scenario

Turkey has plans to install 4800 MW of nuclear capacity by year 2020 which will be granted with purchase guarantees. In our analysis, we test the impact of nuclear power on overall EP industry and its emissions. Nuclear power is introduced as an extra capacity with priority in dispatch, and its financing does not have any effect on the financing of other power generation technologies. Figure 18 summarizes the results.

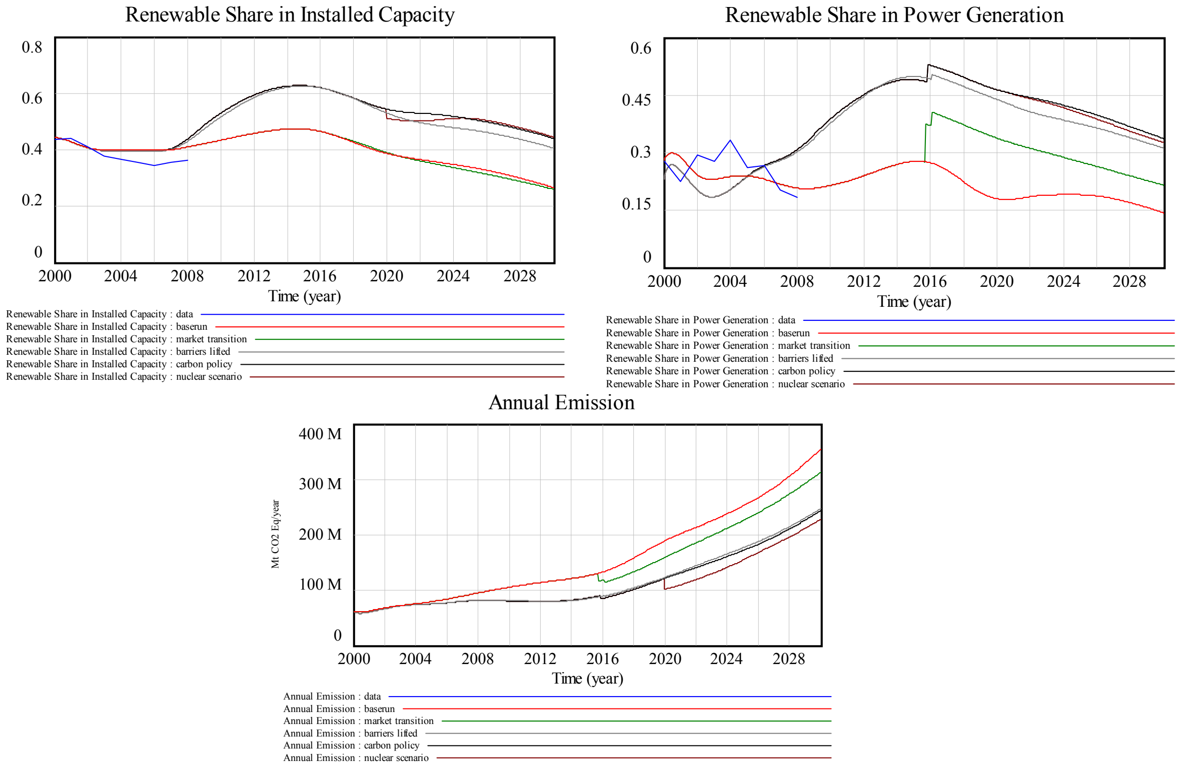

Figure 18. RES Shares and Emissions, Nuclear Power Scenario.

VI. SUMMARY OBSERVATIONS

Through the runs, wholesale price of electricity, reserve margin for the EP industry, supply demand ratios and the wholesale demand are monitored. The outputs illustrate that, in all scenarios, the model operates at ranges that satisfy the demand side. Price is at the range of 4.5 dollar cents/KWh, with an exceptional peak in market transition in 2016. This is because the order of price bids change while they converge to the marginal costs during market transition. For example, the hydro and wind plants are at the fourth and fifth ranks in order before transition. However, as their bids converge to their marginal costs, they become the most preferential electricity providers in the market. These observations are presented in the Appendix.

VI.1. Observations in 2030

Table 4 summarizes the observations in year 2030 for all simulation runs. In the base run (business as usual, BAU), emissions grow by 481%. The growth in the final (nuclear) scenario is 252% and that accounts to a 40% decrease in 2030 with respect to the BAU. In all runs, the large hydropower resources of the country are utilized at levels between 70-80%. Small hydropower natural resource utilization is at 75% in the third scenario and relatively reduced with the existence of nuclear power. Wind power natural resource utilization is at tits peak around 58% in the third scenario and is relatively reduced with the existence of nuclear power. In neither runs, solar generation can take off and its natural resource utilization is at 0. The simulated scenarios and policies cannot create sufficient incentives for solar generation because of its very high costs.

	Carbon emissions ($MtCO_2$ eq.)		**Increase from 2000 (%)**		**Decrease from BAU (%)**		**Large hyd. res. utiliz. (%)**		**Small hydro res. Utiliz. (%)**		**Wind res. Utiliz. (%)**		**Other rnew res. Utiliz. (%)**	
	2000	**2030**	**2000**	**2030**	**2000**	**2030**	**2000**	**2030**	**2000**	**2030**	**2000**	**2030**	**2000**	**2030**
Base run (BAU)		354.5		481.3				73.0		39.1		14.1		
Market transition	61.0	312.5		412.4		11.8	34	72.8	0	42.6	0	14.1	0	0
Tech. con lifted		246.8		304.7		30.4		84.0		69.8		22.7		
Carbon policies		229.6		276.5		35.2		84.7		74.8		58.4		
Nuclear scenario		214.9		252.4		39.4		81.0		74.2		57.6		

Table 4. Observations on Emissions and RES Utilization, 2030.

Pie charts in Figure 19 compare capacity shares in 2000 with capacity shares in 2030 for BAU and the final comprehensive scenario (nuclear).

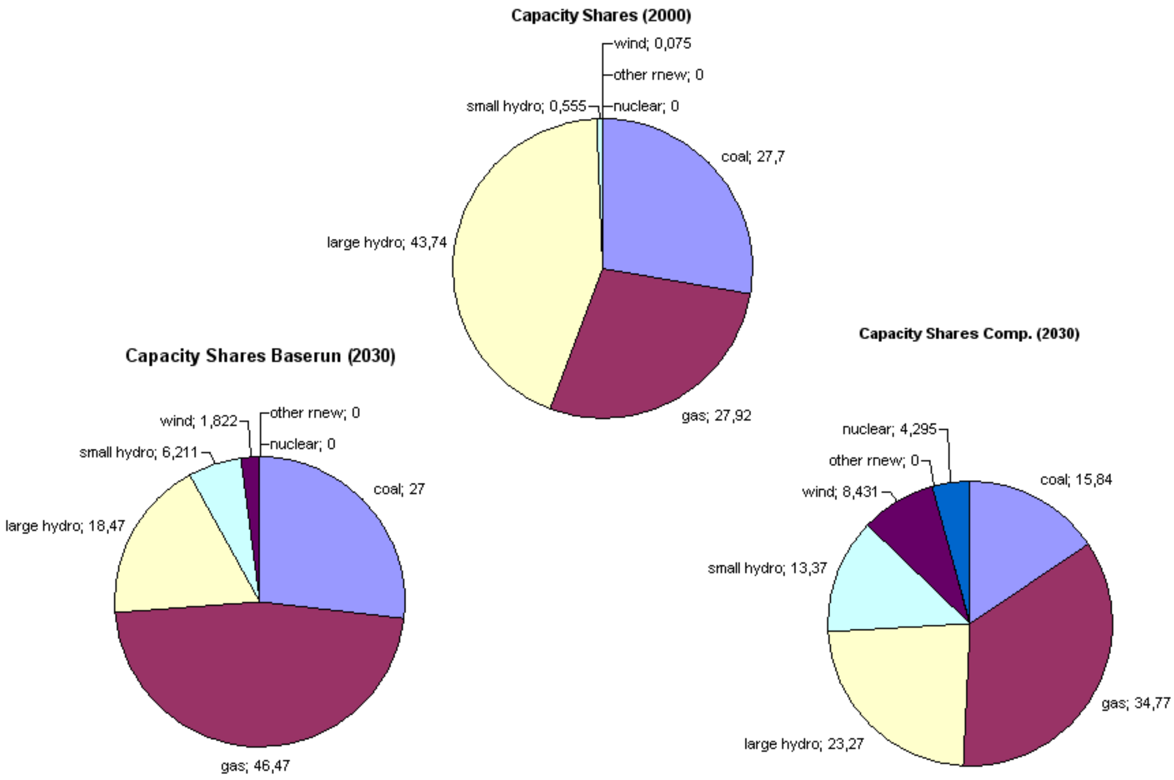

Figure 19. Capacity Shares in 2000 and 2030

Pie charts in Figure 20 compare the generation shares in 200 with generation shares in 2030 for BAU and the final comprehenesive scenario (nuclear).

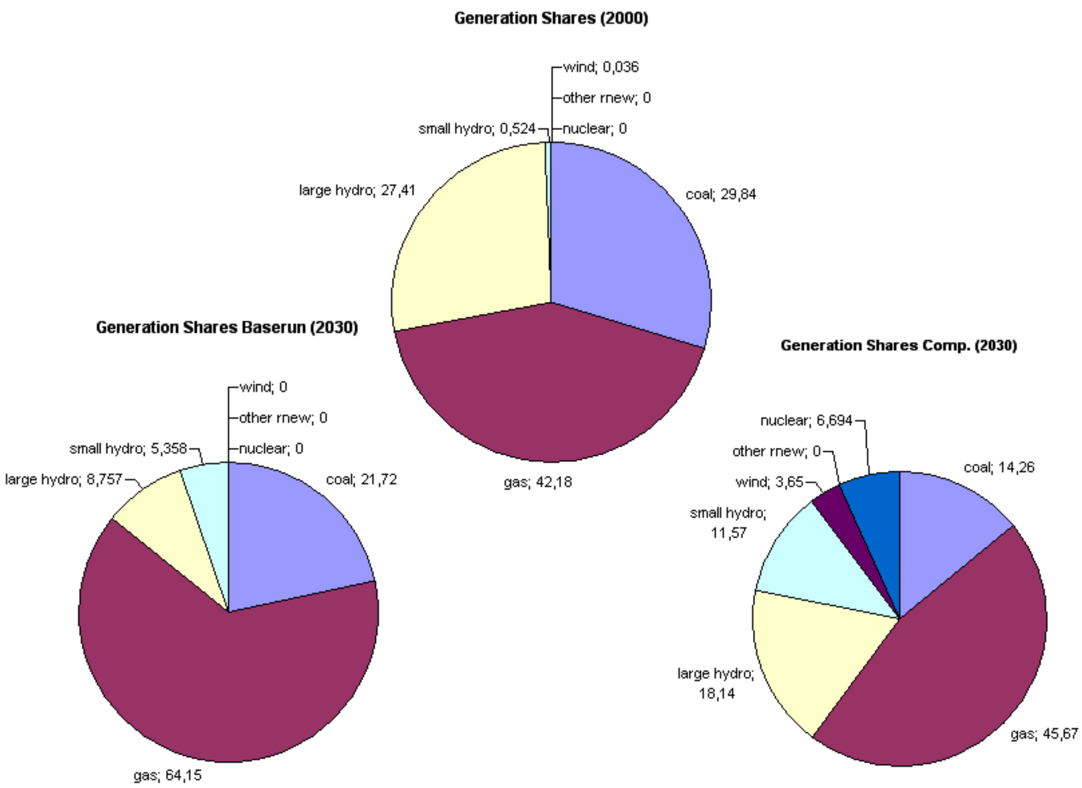

Figure 20. Generation Shares.

VII. CONCLUSION

The dynamic simulation model can be used as an experimental platform to assess the impact of alternative scenarios and carbon mitigation policies on emissions of electric power industry in Turkey. What is presented in this paper is a limited set of results based on selected parameters regarding technical constraints, carbon taxes, investment subsidies and nuclear power investments.

Yet, current analysis show that, for an effective reduction in EP based carbon emissions, demand side control and measures is an imperative. In our base run, wholesale demand grows by 460%, while the emissions grow by 480%. The best result (the most comprehensive run) in terms of carbon emissions show that, wholesale demand growth is reduced to 420% by reducing the reserve margin and transmission losses. Under this background growth, carbon emissions can be reduced by 40% with respect to the BAU, which accounts to a 252% growth with respect to year 2000.

Second, the cost disadvantage for wind and solar power generation technologies, and particularly the disadvantage in solar generation create a strong barrier against carbon reduction. For effective control in carbon emissions from EP industry, retrofits of existing fossil fuel based capital, technological learning in carbon capture and storage technologies and in solar generation is an imperative, together with demand side control. Research in both in technology and management should concentrate their efforts on these aspects of the problem.

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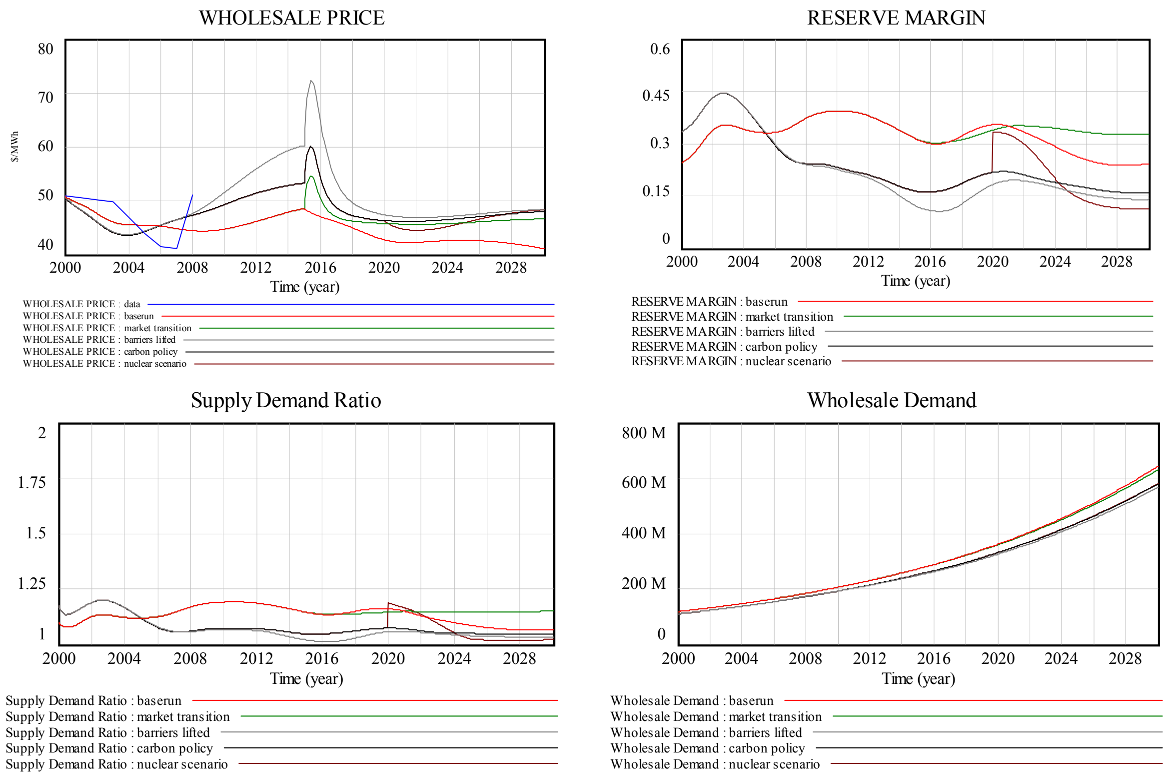
APPENDIX. PRICE, DEMAND, RES. MARGIN AND SUPPLY DEMAND RATIOS



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