Energy and Emissions Long Term Outlook

A Detailed Simulation of Energy Supply-Demand

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The paper presents the results of a detailed, bottom-up modeling exercise of Mexico's energy markets. The Energy and Power Evaluation Program (ENPEP), the Wien Automatic System Planning (WASP) and the Energy Demand Model (MODEMA) were used to develop forecasts to 2025. Primary energy supply is projected to grow from 9,313 PJ (1999) to 13,130 PJ (2025). Mexico's crude oil production is expected to increase by 1% annually to 8,230 PJ. As its domestic crude refining capacity becomes unable to meet the rising demand for petroleum products, imports of oil products will become increasingly important. The Mexican natural gas markets are driven by the strong demand for gas in the power generating and manufacturing industries which significantly outpaces projected domestic production. The result is a potential need for large natural gas imports that may reach approximately 46% of total gas supplies by 2025. The long-term market outlook for Mexico's electricity industry shows a heavy reliance on natural-gas based generating technologies. Gas-fired generation is forecast to increase 26-fold eventually accounting for over 80% of total generation by 2025. Alternative results for a constrained-gas scenario show a substantial shift to coal-based generation and the associated effects on the natural gas market. A renewables scenario – investigates impacts of additional renewables for power generation (primarily wind plus some solar-photovoltaic). A nuclear scenario – analyzes the impacts of additional nuclear power generation capacity. Total CO_2 emissions are projected to grow an average of 3.4% annually, eventually reaching 828 million tons/year by 2025. Transportation-related emissions exhibit the strongest growth and by 2025 account for 45% of total CO_2 emissions. The CO_2 emissions from the power generation grow only at 2.6% per year due mostly to the increased reliance on natural gas. National NO_X emissions are estimated to increase by 235% (1999-2025) with transportation being the largest contributor followed by the power industry. Country's sulfur emissions decline from 2.4 million tons in 1999 to 1.2 million tons in 2008 mostly because of developments in the power industry. The continued combustion of fuel oil in the manufacturing sector leads to a gradual increase in sulfur emissions after 2008 eventually reaching 1.8 million tons by 2025. Alternative results examine the effects of renewables and nuclear power on energy and emissions as well as the environmental implications.

1. The present energy system

In Table 1 the supply and demand structure of Mexican energy system corresponding to the years from 1998 up to 2001 are shown. The internal energy supply, for those years, has an 86% to 88% dependence on fossil fuels. For example, in 2001 fossil fuel dependence was 87.6%, of which crude oil and condensates account for 53.63%, natural gas for 30.8%, oil derivatives 9.17% and coal and coke 6.40%. Sugar case bagasse account for 1.44%. Fuel wood still plays a significant role, 4%, being still the sole source of energy for many small rural communities and thus contributing to the deforestation problem of the country. In 2001 the net installed electric capacity was 37,063 MW having delivered 192,517 GWh. To generate this electricity the energy mix was fuel oil (45.5%), natural gas ((20.13%), diesel (0.93%), coal (11.29%), hydro (14.51%), geothermal (2.84%), nuclear (4.81%) and a small amount from wind.

For the same year, the end use energy structure consisted of gasoline and naphtha (26.8%), natural gas (10.32%), diesel (13.76%), fuel oil (4.89%), LPG (11.26%), kerosene (2.96%), electricity (14.44%), coke (2.95%), fuel wood (6.49%), sugar cane bagasse (2.33%) and non-energy products (3.79%).

The environmental problems (local and global) arising from the energy system follows from:

1. The overwhelming dependence on hydrocarbons, coal and fuel wood; the characteristics of the crude oil refined and the lack of forestry management.
2. The large and still growing urban concentrations, led by the Metropolitan Area of Mexico City, with insufficient –or without- massive transport systems.
3. The lack –until some years ago- of any concern or measures of emission's control by the energy sector, the transport sector and the industry in general.
4. The inefficient use of energy.

Table 1. 1998-2001 Internal Energy Balances

Energy Supply	**1998**		**1999**		**2000**		**2001**	
	PJ	*%*	*PJ*	*%*	*PJ*	*%*	*PJ*	*%*
Domestic production								
Hydrocarbons	8,561.36	83.04	8,270.30	81.91	8,596.61	82.06	8,700.85	82.74
Biomass (Bagasse and firewood)	343.19	3.33	341.50	3.38	341.91	3.26	348.85	3.32
Hydraulic	252.96	2.45	336.15	3.33	344.22	3.29	291.82	2.78
Coal	199.41	1.93	200.47	1.99	226.70	2.16	239.07	2.27
Geothermal	58.13	0.56	57.78	0.57	61.41	0.59	57.13	0.54
Nuclear	100.47	0.97	108.26	1.07	90.33	0.86	96.70	0.92
Wind	0.05	0.00	0.06	0.00	0.08	0.00	0.07	0.00
Subtotal domestic production	***9,515.57***	***92.29***	***9,314.51***	***92.26***	***9,661.27***	***92.22***	***9,734.49***	***92.57***
Imports	777.69	7.54	731.74	7.25	862.38	8.23	872.37	8.30
Inventory changes	16.88	0.16	50.07	0.50	-47.37	-0.45	-91.60	-0.87
Exports	-3,937.82	-38.19	-3,588.48	-35.54	-3,857.60	-36.82	-3,932.29	-37.40
Others (Spills, flaring,…)	-175.49	-1.70	-190.35	-1.89	-188.79	-1.80	-146.27	-1.39
Maquila	0.00	0.00	-37.01	-0.37	-61.49	-0.59	-35.38	-0.34
Total internal energy supply	**6,196.83**		**6,280.49**		**6,368.41**		**6,401.33**	
Transformation								
Oil and gas sector	45.21	0.82	178.37	3.25	235.89	4.30	289.60	5.28
Electric sector	1,141.50	20.80	1,207.68	22.01	1,303.09	23.75	1,301.35	23.72
Coke	4.74	0.09	4.78	0.09	4.81	0.09	4.44	0.08
Self-consumption	826.89	15.07	811.18	14.78	825.59	15.05	850.70	15.50
Statistical differences	52.92	0.96	112.19	2.04	174.18	3.17	124.92	2.28
Losses (trans., dist., and storage)	129.59	2.36	131.14	2.39	134.63	2.45	138.90	2.53
Subtotal transformation	***2,095.01***	***38.18***	***2,220.96***	***40.48***	***2,329.83***	***42.46***	***2,460.07***	***44.83***
End use sectors								
Industrial[a]	1,600.50	29.17	1,539.12	28.05	1,471.53	26.82	1,388.84	25.31
Transport	1,530.26	27.89	1,557.46	28.38	1,614.23	29.42	1,600.31	29.16
Residential and Commercial	846.11	15.42	833.79	15.20	816.17	14.87	820.22	14.95
Others[b]	124.96	2.28	129.16	2.35	136.66	2.49	131.90	2.40
End use subtotal	***4,101.83***	***74.75***	***4,059.53***	***73.98***	***4,038.58***	***73.60***	***3,941.26***	***71.83***
Total	**6,196.83**		**6280.49**		**6,368.41**		**6,401.33**	

[a] Includes the energy uses and feed stocks

[b] Includes the Agricultural and Public sectors

Table 2 shows an estimation of the overall emissions associated with the internal energy consumption. To this we should added the CO_2 emissions arising from the cement production. The Table also shows an estimation of the CO_2 emissions associated with the fuel wood consumption.

Table 2. Energy related emissions

	1999	2000	2001
CH_4 (thousand tons/year)	179.39	176.61	184.54
CO (thousand tons/year)	11,009.80	11,335.85	11,257.80
CO_2 (million tons/year)	346.10	357.86	354.48
CO_2 biomass (million tons/year)	37.73	37.15	37.55
N_20 (tons/year)	3,425.50	3,488.58	3,473.82
NMVOC (thousand tons/year)	1,752.18	1,811.97	1,796.00
NO_X (thousand tons/year)	1,516.36	1,585.64	1,536.47
PM (thousand tons/year)	323.20	324.31	304.20
SO_2 (thousand tons/year)	2,347.41	2,359.88	2,084.23

2. Modeling approach

The Mexican study was carried out by using the combination of a set of energy models that were provided by the International Atomic Energy Agency and Argonne National Laboratory, and a national model as can be seen in the Figure 1.

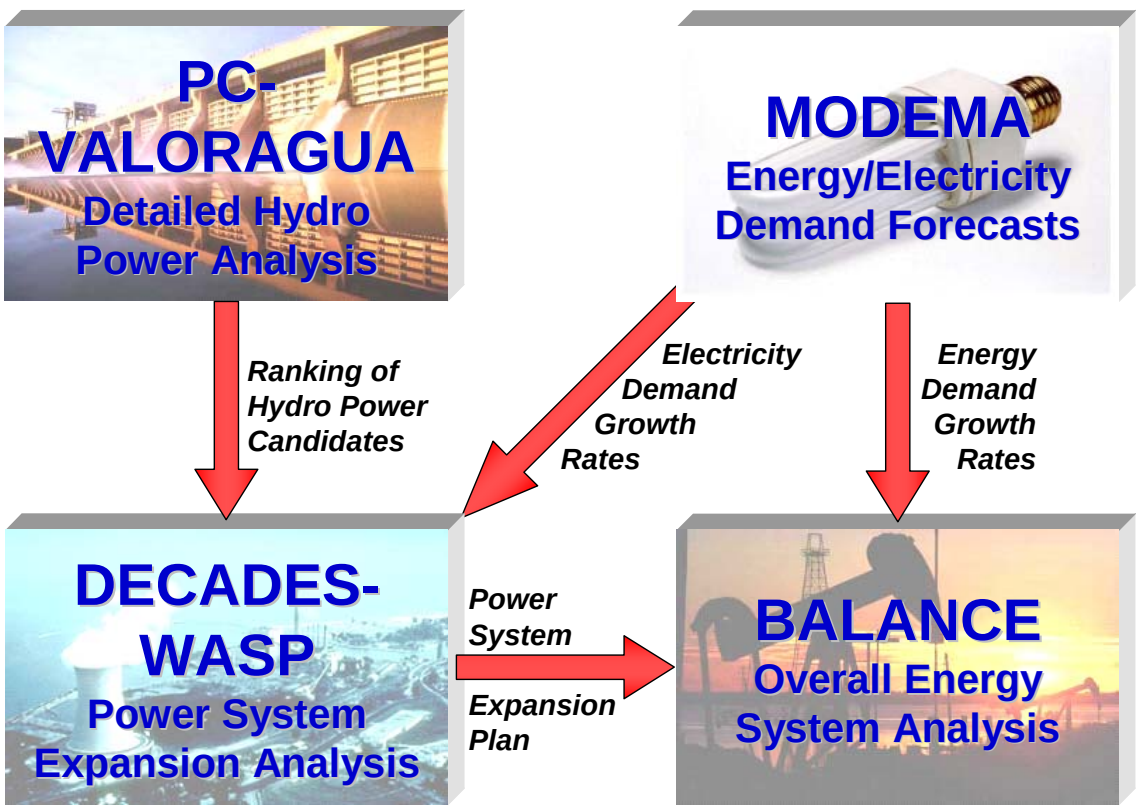

Figure 1. Modeling framework

The ***PC-VALORAGUA*** model was used to determine the optimal strategy of mixed hydrothermal electric power systems by ranking them. The optimal operation strategy is obtained for the system as a whole, with an emphasis on detailed simulation and optimization of the hydro subsystem operation. The model

can simulate the operation of all types of hydropower plants (run-of-river, weekly, monthly, seasonal, or multi-annual regulation), including pumped-storage plants and multipurpose hydro projects.

The ***WASP (/DECADES)*** model (Wien Automatic System Planning Package) was used to determine the power sector expansion and estimate unit generation and fuel consumption levels. The model determines an electric system expansion plan that meets the growing demand for electricity at minimum cost while respecting user-specified constraints, such as desired system reliability, fuel limitations, or environmental constraints. The optimum is evaluated in terms of the minimum present worth of total system expansion and operating costs. WASP uses probabilistic simulation of production costs, energy-not-served costs, and system reliability parameters to compare total costs of alternative expansion policies. Each possible sequence of power units added to the system (expansion plan or policy) that meets the constraints specified by the user is evaluated by a cost function (the objective function). The optimal expansion path is then determined using a dynamic programming algorithm. For the analysis of mixed hydrothermal power systems, WASP is frequently used in combination with the PC-VALORAGUA model. The expansion analysis conducted with the WASP/VALORAGUA methodology provides an enhanced representation of hydro power plants and their operation in the electric power system.

DECADES model was used to carry out the Comparative Assessment of Energy Sources for Electricity Supply until 2025 and the results for this power system expansion analysis were transferred to ***ENPEP*** model.

The ***BALANCE*** module of the ***ENPEP*** model uses a nonlinear, market-based equilibrium approach to determine the energy supply and demand balance for the entire Mexican energy system. The model makes use of a graphical network representation of the energy system that is designed to trace the flow of all energy forms from primary resource level to final or useful energy demand, that is, transportation gasoline, residential hot water, or industrial process steam.

The nonlinear, equilibrium BALANCE module matches the demand for energy with available resources and technologies. Its market-based simulation approach allows BALANCE to determine the response of various segments of the energy system to changes in energy prices and demand levels. The model relies on a decentralized decision-making process in the energy sector and can be calibrated to the different preferences of energy users and suppliers. Basic input parameters include information on the energy system structure; base year energy statistics, including production and consumption levels, and prices; projected energy demand growth; and any technical and policy constraints (Figure 2).

In this process, an energy network is designed to trace the flow of energy from primary resources to useful energy demands in the end-use sectors. The BALANCE networks are constructed using different nodes and links, which represent the components of the modeled energy system. The nodes in the network represent depletable and renewable resources, various conversion processes, refineries, thermal and hydro power stations, cogeneration units, boilers and furnaces, marketplace competition, taxes and subsidies, and energy demands. Links connect the nodes and transfer information among nodes.

The model employs a market share algorithm to estimate the penetration of supply alternatives. The market share of a specific commodity is sensitive to the commodity's price relative to the price of alternative commodities as shown in Figure 3. User-defined constraints (*e.g.,* capacity limits), government policies (taxes, subsidies, priority for domestic resource over imported resource, etc.), consumer preferences, and the ability of markets to respond to price signals over time (*i.e.,* due to lag times in capital stock turnover) also affect the future market share of a commodity.

Using a market share algorithm distinguishes the equilibrium approach from other modeling techniques. The BALANCE approach simulates more accurately the more complex market behavior of multiple

decision makers that optimization techniques may not be able to capture because they assume a single decision maker. Every sector (electric, industrial, residential, etc.) pursues different objectives and may have very different views of what is "optimum." The equilibrium solution develops an energy system configuration that balances the conflicting demands, objectives, and market forces without optimizing across all sectors of the economy.

Figure 2. BALANCE module of ENPEP

BALANCE simultaneously finds the intersection of supply and demand curves for all energy supply forms and all energy uses included in the energy network. Equilibrium is reached when the model finds a set of market clearing prices and quantities that satisfy all relevant equations and inequalities. The model employs the Jacobi iterative technique to find the solution that is within a user-defined convergence tolerance.

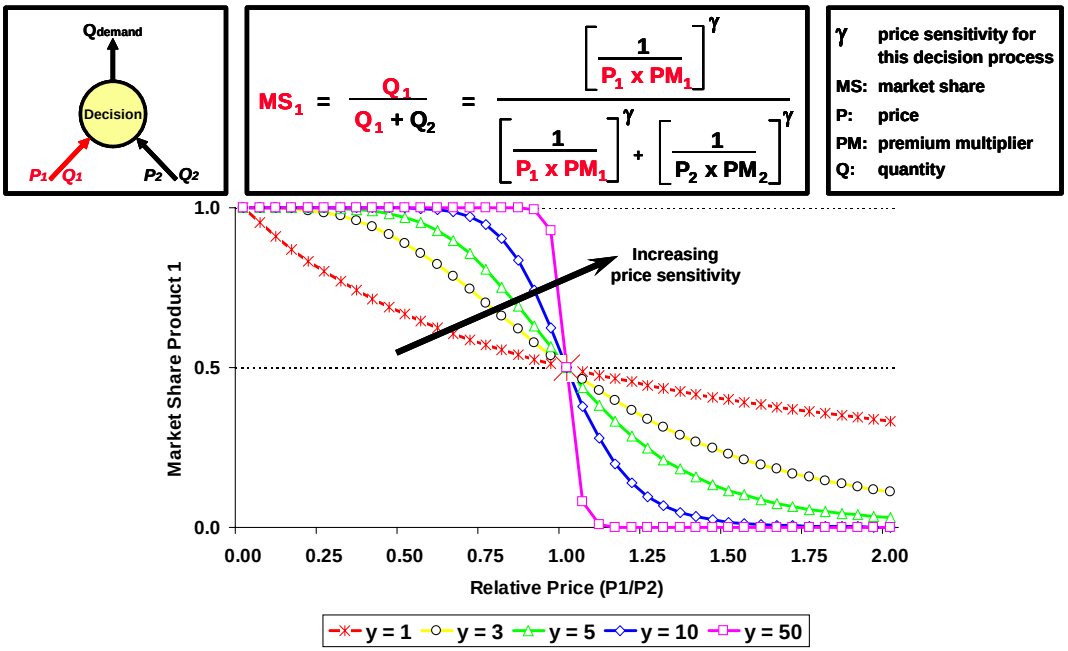

Figure 3. BALANCE market-share algorithm

Concurrently with the energy calculations, the model computes the environmental residuals associated with a given energy system configuration. In addition to greenhouse gases and standard criteria air pollutants, residuals may include waste generation, water pollution, and land use. Greenhouse gas emissions can be reported in a format that is compatible with the Intergovernmental Panel on Climate Change. In this analysis, a total of 8 pollutants were implemented, however, in an effort in progress we will implement the model to include up to 30 pollutants. This includes all major GHG emissions, as well as several particulate matter (PM) species, sulfur dioxide (SO_2), nitrogen oxides (NO_X), air toxics including several species of heavy metals, and solid wastes.

MODEMA is an energy demand model whose projections consider the detailed behavior of the main energy consuming sectors and sub-sectors, as well as their projected consumptions and diversification possibilities. The model was developed by the Dirección General de Servicios de Cómputo Académico (DGSCA) and Programa Universitario de Energía (PUE), both institutions of the Universidad Nacional Autónoma de México (UNAM).

MODEMA is as a top-down simulation model for the primary and final energy demand. As a simulation model, the size and the sectoral structure of the energy demand are determined by the evolution of the determining variables that, as a set, define the behavior of the socioeconomic activity, and their causal relation with the energy demand. The model breaks up the economy into sectors and sub-sectors, as shown in Figure 4, and analyses their participation in the national economy. In this way, the future total energy demand will depend of the economy and energy expectations of each sector and upon their relative weight. As a consequence, it allows for an individual analysis of the main sectors and thus gives a more representative energy demand projection than a general energy-gross domestic product (GDP) relationship. Additionally, it has the option of introducing policy instruments, such as those seeking energy conservation and thus, of analyzing the effects of proposed policies on energy demand. Therefore the model provides the total energy demand projections and also includes the demand by type of energy source for the sectors and sub-sectors.

The sectors of the economy are divided into net productive and net consumer ones. The productive sectors and sub-sectors are characterized by their participation (%) in the GDP and their energy intensity (E/$); the second ones, namely the residential sector, by the population distribution (%) into urban and rural and their consumption per capita (E/capita). The historical and projected evolution of the population and its structure is taken from governmental data. With respect to the GDP growth, historical data is use for the model's calibration and GDP growth scenarios for the projection horizon. To obtain the demand by energy source the matrices of energy source by sector and sub-sector are used and by using the emission matrix, the emissions by source are computed, and finally the emissions associated with each sector can be aggregated.

3. Energy network configuration

For the analysis of the total energy system in Mexico, the entire energy network of the considered sectors was defined and developed in ENPEP's graphical user interface, as presented in Figure 5. In addition to 3 resource supply sectors, the network includes 9 conversion and distribution sectors as well as 21 demand sectors and sub-sectors. Industrial sector is divided into 17 individual industrial branches. Each sector and sub-sector was then defined at a level of detail that matches the available data for the sector, sub-sector and is appropriate for the types of issues to be analyzed.

Table 3 shows an explanation of the supply and demand sectors, sub-sectors, fuels, electricity distribution and the abbreviations in Figure 5. The Residential, Commercial and Public sector as well as the Transport and Agricultural sectors were split into the different demand sub-sectors and uses.

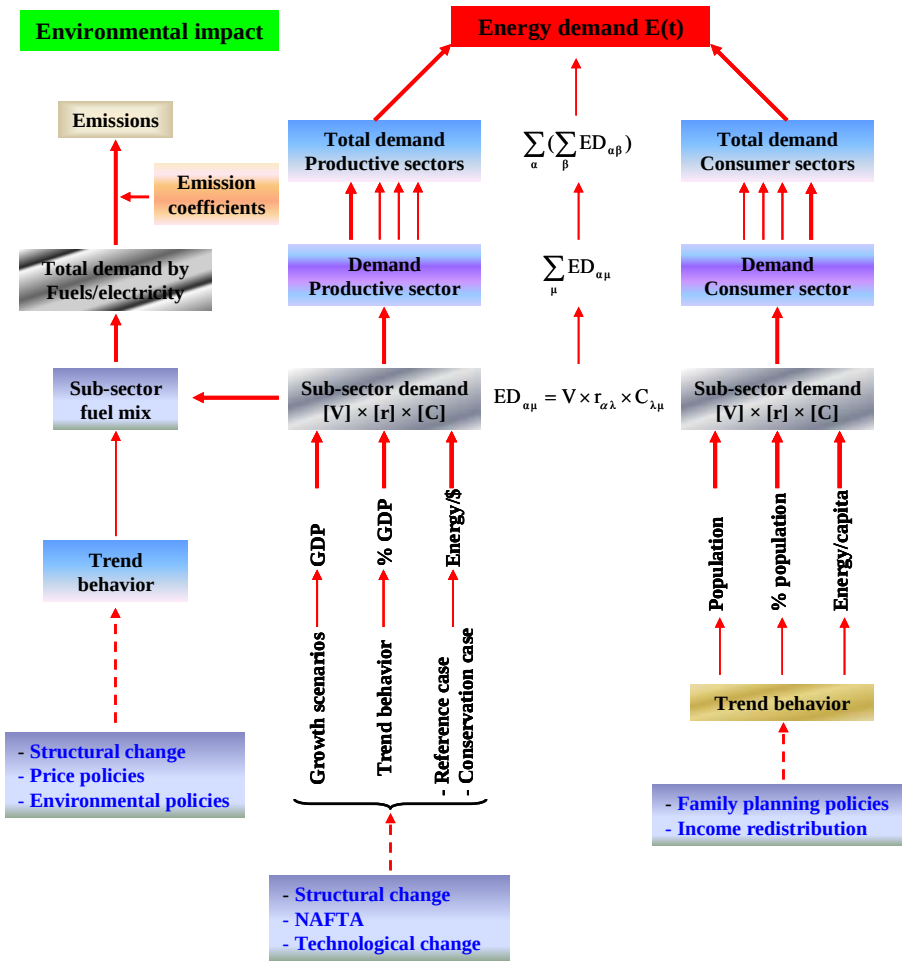

Figure 4. MODEMA: Energy Demand Model

An initial attempt was made to configure the model at the regional level. However, lack of information, in particular demand side data but also oil and gas sector data, prevent to carry out this and require an effort at national-level implementation. Nevertheless, a work on progress will cover part of the initial objective in an updated model configuration.

Figure 6 presents the oil and gas sector implementation. Oil and gas production consist of crude oil, condensates and associated and non-associated gas. After separating out the associated gas, crude oil and condensates are processed in the oil refining step into the different petroleum fuels, such as, gasoline, diesel, fuel oil, LPG, non-energy products, etc. Wet gas and wet associated gas moves through the gas processing plants to produce natural gas and to remove natural gas liquids. Gas liquids and condensates are processed in the fractionating step into oil products, such as LPG, gasoline, diesel, fuel oil and non-energy products, etc. Dry natural gas and gas imports are sent directly to the T&D sectors for distribution to the final consumers. Also included in the sector is the "maquila" process whereby Mexico is sending crude oil to foreign refineries, and receives back petroleum products, primarily gasoline and diesel.

Mexico's power system is generally divided into nine generation regions, six of them are interconnected and three are isolated, that is, Baja California, Baja California Sur, and the Northwest Region. In 1999, the interconnected system accounted for 85% of installed capacity and 88% of generation and was modeled in detail at the unit level.

Table 3. Sectors, sub-sectors, fuels and electricity nodes and abbreviation nodes

Supply sector	Demand sector and sub-sector	Fuels and electricity distribution
COAL: Coal supply	RESID: Residential sector	GASOL: Gasoline distribution
OIL: Oil and natural gas supply	COPUB: Commercial and Public sector	NATG: Natural gas distribution
NUCL: Nuclear supply	AGRIC: Agriculture sector	FOIL: Fuel oil distribution
ELECT: Electricity supply	TRANS: Transport sector	LPG: LPG distribution
	SIDER: Iron and steel sub sector	DIESE: Diesel distribution
	GLASS: Glass sub-sector	KEROS: Kerosene distribution
	SUGAR: Sugar sub-sector	NENER: Non energy products distribution
	CEMEN: Cement sub-sector	ELT&D: Electricity distribution
	PPCHE: PEMEX Petrochemical sub-sector	
	FERTI: Fertilizers sub-sector	
	CHEMI: Chemicals sub-sector	
	MININ: Mining sub-sector	
	PAPER: Paper and cellulose sub-sector	
	BEER: Beer and malt sub-sector	
	AUTO: Automotive sub-sector	
	CONST: Construction sub-sector	
	RUBBE: Rubber sub-sector	
	BWATE; Bottled soft waters sub-sector	
	ALUMI: Aluminum sub-sector	
	TOBAC: Tobacco sub-sector	
	OTHER: Other sub-sectors	

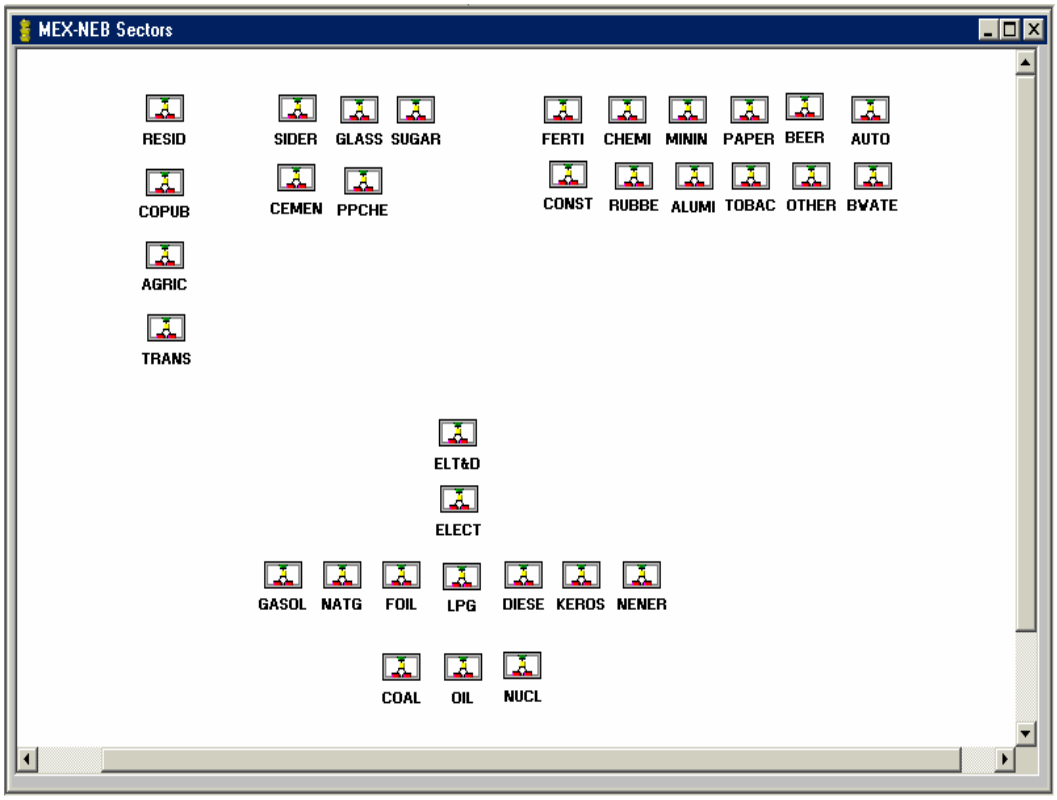

Figure 5. ENPEP network for Mexico

In 1999 total net installed capacity was 35,666 MW, it consisted of 574 power units, its structure was 97 steam units (14,282.5 MW), 6 dual units (2,100 MW), 33 combined cycle units (2,463.42 MW), 90 gas turbine units (2,363.78 MW), 82 internal combustion units (117.66 MW), 28 geothermal units (749.90 MW), 8 coal units (2,600 MWW), 2 nuclear units (1,368 MW), 8 wind units (2.18 MW) and 220 hydro units (9,618.15 MW).

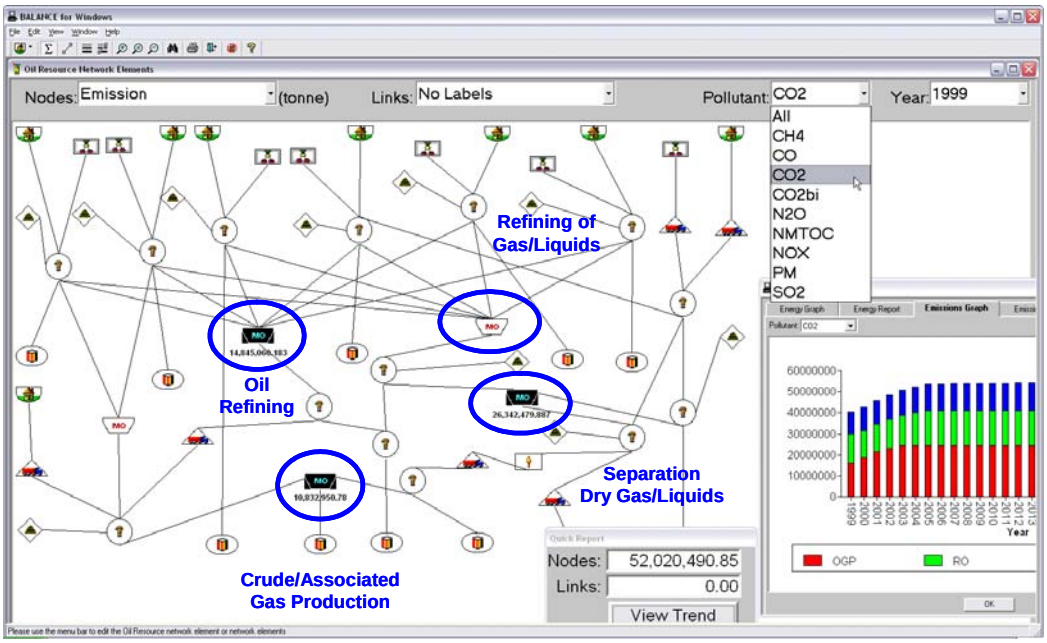

Figure 6: Oil and Gas Sector Representation

Total gross generation was 180,917.4 GWh. Generation structure by technology was steam (85,103.95 GWh), dual (11,233.74 GWh), combined cycle (15,526.36 GWh), gas turbine (2,077 GWh), internal combustion (381.55 GWh), geothermal (5,623.1 GWh), coal (18,250.6 GWh), nuclear (10,001.59 GWh), wind (6.15 GWh) and hydro (32,713.44 GWh).

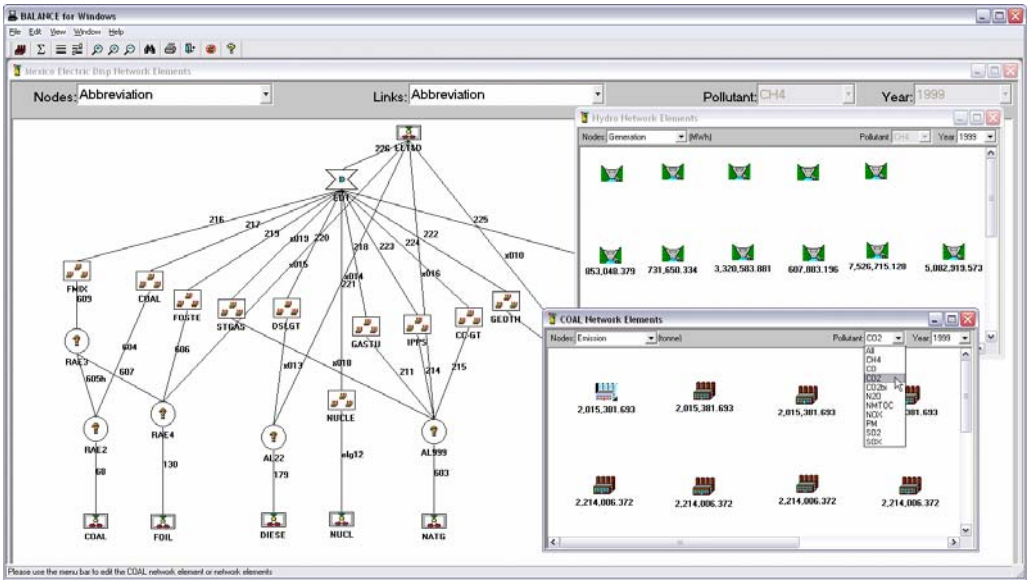

Figure 7. Interconnected power sector representation

For convenience, the user can group the individual units into different fuel groups. It was decided to group them into 9 thermal groups and 1 hydro group. The Figure 7 shows the configuration for the interconnected system with the fuel groups and unit details for two groups (hydro and fuel oil). Less detailed information was available for the isolated grid. Therefore, the isolated system was modeled in a simpler, more aggregated approach. The isolated grid is shown in the Figure 8. Non-dispatchable renewables are also included in this network sector.

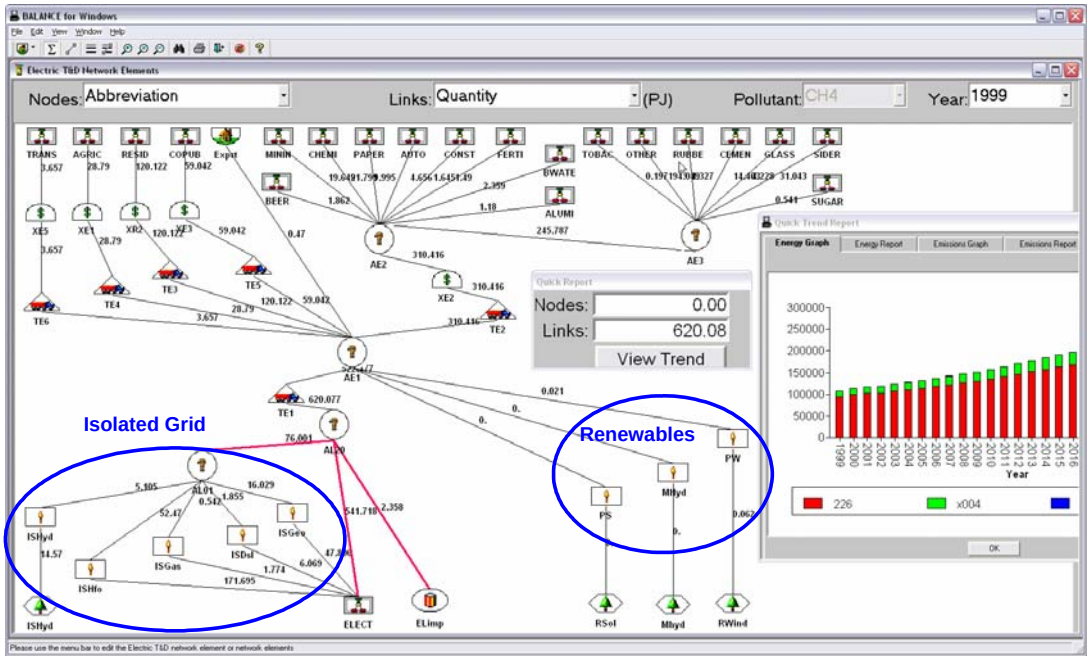

Figure 8. Isolated power sector representation

There are a number of transmission and distribution (T&D) sectors in the network, particularly for the various petroleum products and the power sector. The T&D sectors incorporate distribution costs (if available) and government taxes and subsidies (if applicable).

The model computes the end-use energy prices across the different sectors to send the correct price signals to consumers. Figure 9 shows, as an example, the diesel distribution network and Figure 10 presents the sugar industry as an example of an end-use sector. As can be seen, various furnaces, boilers, and co-generators compete to supply the sugar industry's demand for direct heat and process steam. Cogeneration provides an alternate supply to grid-purchased electricity.

4. Scenarios and main assumptions

The analysis period is 1999 to 2025 with the first 3 years used to calibrate the ENPEP-BALANCE model to the Mexican situation. Economic growth is assumed to be 4.5% (2002-2011) and 3.5% (2012-2025). Assumed population growth rates drop from 1.33% (2000-2010) to 1.02% (2011-2020) and 0.82% for the remainder. Fuel price escalation rates were developed based on Bates (2002) who estimated fuel price indexes using information from the World Bank and USEIA. The discount rate is taken as 10% in all scenarios.

For the power sector, the study examined a total of 14 scenarios, including a base case. The scenarios include variations in the load growth, variations in the assumed natural gas availability, the sensitivity to

changes in the projected prices for the fuels, different system reliability targets, as well as the possibility for additional nuclear capacity. Forecasts until 2025 for the entire Mexican energy system were developed for the following four scenarios:

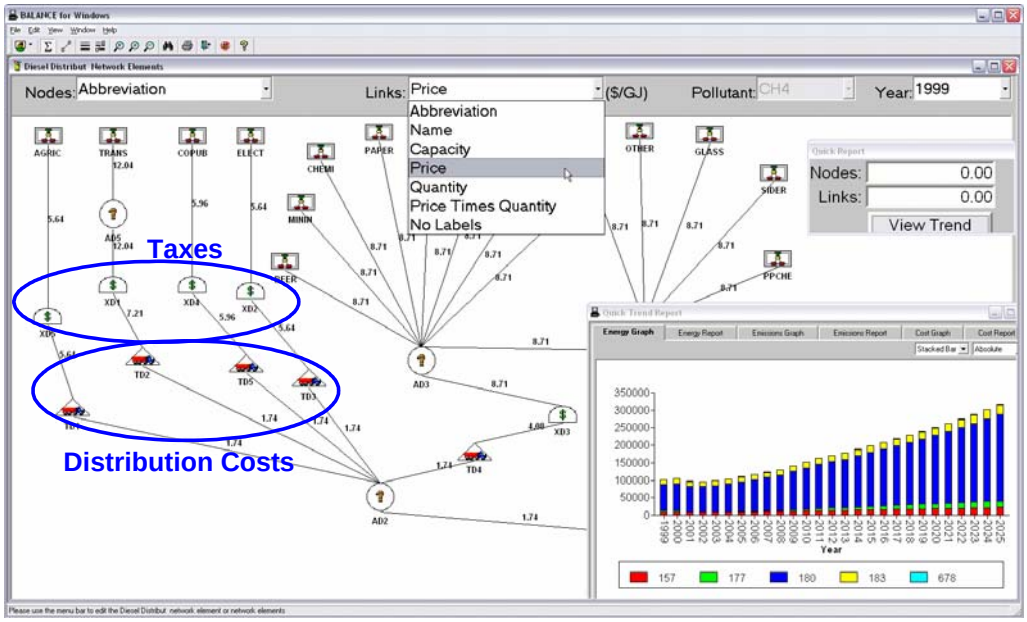

Figure 9. Diesel transportation and distribution network

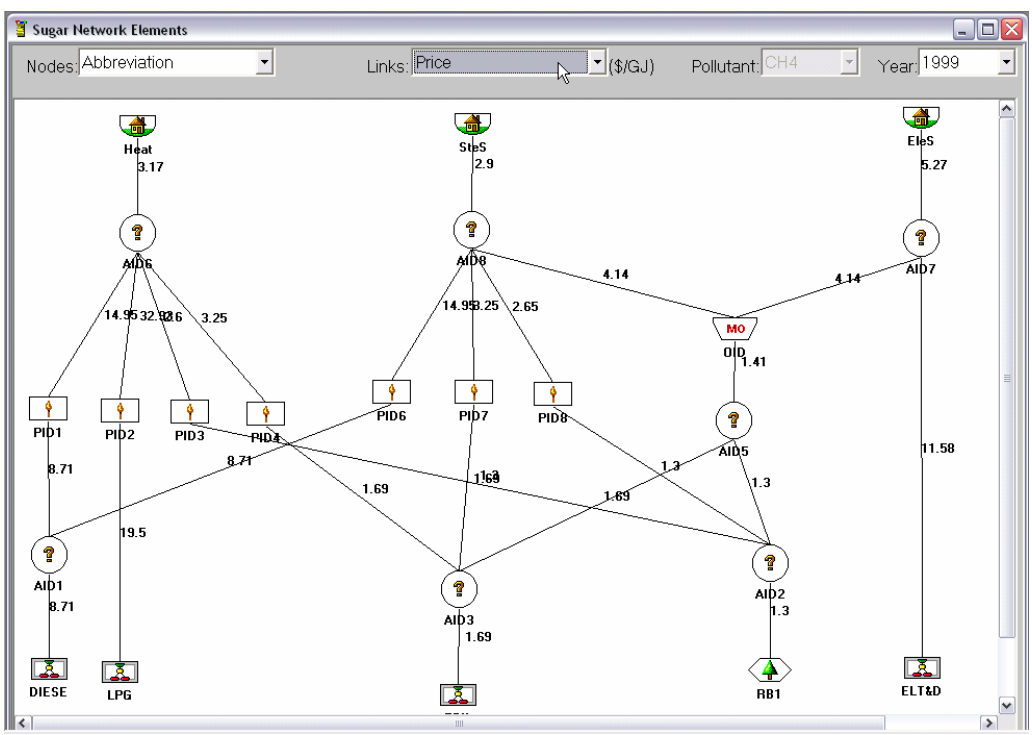

Figure 10. End-use sector representation (sugar industry)

- **Reference case;** assumes that there are no constraints on the supply of natural gas, in other words there is an unlimited supply of natural gas;

- **Limited gas scenario;** assumes limited gas supply for power generation starting in 2009 (maximum addition of 3 combined cycle units per year);

- **Renewables scenario;** investigates impacts of additional renewables for power generation (primarily wind plus some solar-PV);

- **Nuclear scenario;** analyzes the impacts of additional nuclear power generation capacity.

5. Results

A. Reference case results

A1. Primary energy results

Primary energy supply will increase from 9,312.3 PJ to 13,126.5 PJ along the projection period. Crude oil market share decrease from 68.2% in 1999 to 62.7% in 2025, as a consequence of the non-associated gas growth share in 11.9% in 2025 (compared with 4.5% in 1999) meanwhile associated gas decrease from 13.9% in 1999 to 12.8% in 2025 as shown in Figure 11. Non-associated gas growth rate is the highest (5.2%) followed by coal (3.7%), crude oil (1.0%), geothermal (0.8%) and sugar cane (0.2%). For the nuclear contribution it is important to know that first unit of Laguna Verde nuclear power plant will be closed in 2025.

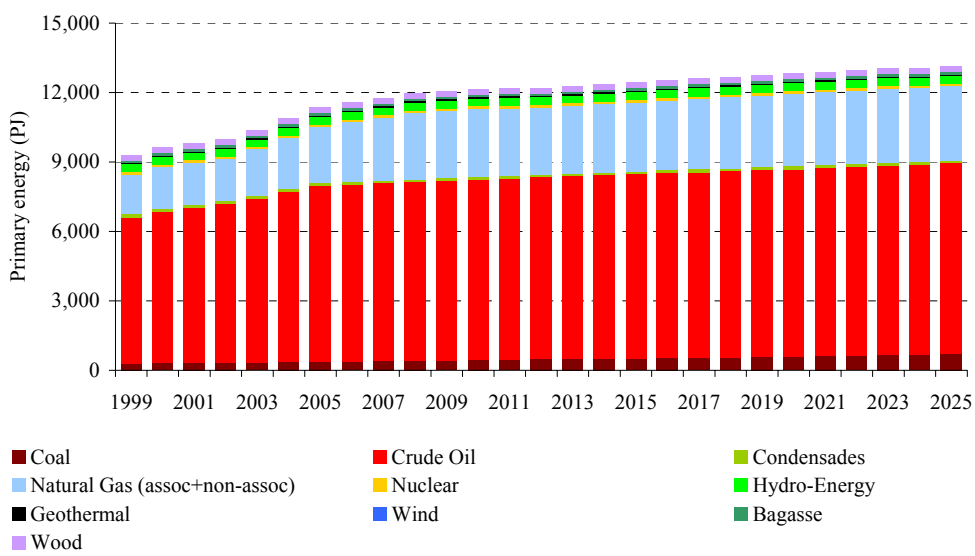

Figure 11. Total primary energy supply (Reference case)

Mexico is a producer and an important exporter of crude oil, however, is an importer of refined oil products. Oil production in 1999 amounted to 6,352 PJ and it is projected that in 2025 will be of 8,232 PJ. That means a growth rate of 1.0%.

The main assumptions under which this oil production are projected were: 1) country's total refining capacity is set to 1.565 million barrels per day and no additions of new capacity along the projection period, 2) the driving oil product is gasoline, 3) the capacity available under the maquila's mechanism is

set to the maximum capacity of the current agreements, 4) excess demand of gasoline, after domestic refining and maquila's contribution, are satisfied through imports and 5) oil exports will increase at a decreasing growth rate, from 6.94% from 1999 to 2000 up to 0.55% from 2024 to 2025.

Figure 12 shows the projected oil production in barrels per day. If the projected increase in the refining capacity (the addition of 160,000 barrels per day by the year 2006) becomes on line this will reduce the amount of crude oil sent to maquila for some time, however, it would not represent a reduction in the oil production. On the other hand, the behavior of the crude oil exports will have a direct impact on the oil production and will depend, directly, on the crude oil exports policy and economic considerations. Also, changes in the economic and population scenarios, considered in the present study, will have, to some extent, an impact on the results for the projected oil production.

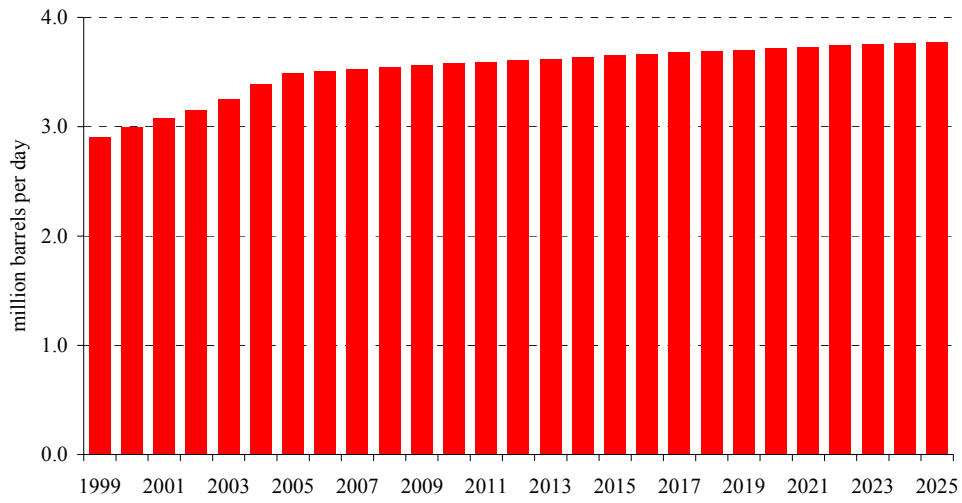

Figure 12. Projected crude oil production (Reference case)

Imports of gasoline and diesel have become an essential component for the domestic market, fact that forces to the refinement industry to become strong in order that in a modern and flexible form be able to face the challenges of a dynamic internal market. In 1999, after self-consumption the gasoline yielding of the National Refining System (NRS) was 25.34%. Under these yielding conditions the existing refining capacity (1.525 million barrels per day of atmospheric distillation) was not enough to satisfy the required gasoline production from the country's refineries.

By year 2006, is expected to have a new refinery with a capacity of 160,000 barrels per day plus the additions from the phases in progress of the reconfiguration program and a gasoline yielding of 32.8%, the total refining capacity will be 1.715 million barrels per day. Under these conditions there will be a deficit of refining capacity of 27,000 barrels per day. This deficit could be covered by a reduction in the gasoline exports; however such action will have impact on the route of the aggregated value for the oil resource.

For year 2008 and the rest of the projection period, after the completion of the reconfiguration program and with a gasoline yielding of 39%, the total refining capacity will have to increase to the following total capacities: 1.943 million barrels per day for 2008; 2.480 million barrels per day for 2015; 3.157 million barrels per day for 2020; 4.070 million barrels per day for 2025. Therefore, the accumulated increase capacity along the projection period will be 2.355 million barrels per day. The elimination of the gasoline exports will have the effect to lower the required capacity, by 2025, to 2.1 million barrels per day. The penetration of other fuels, in substitution of gasoline, will, also, have the effect to reduce the required refining capacity.

The total natural gas supply grows from 1,776.6 PJ to 5,935.1 PJ along the projection period. This means a growth rate of 4.8%, led especially by the imports that arise from 59.9 PJ to 2,689.8 PJ in the same period and its market share will be of 45.3% in 2025 for total gas supply, upper from 3.4% in 1999.

As in the case of oil production, the projections of natural gas production were developed under some assumptions, namely: 1) total capacity of gas plants is fix and equal to 5,034 million cubic feet per day, 2) total capacity of fractionating plants is also fix and equal to 554 million cubic feet per day, 3) natural gas exports are marginal with a decreasing pattern and 4) no capacity additions for gas and fractionating plants along the entire projection period. Additionally, the ratio crude oil to associated gas is kept constant and equal to the average value of the last few years.

The natural gas production in 1999 was of 4,398.37 million cubic feet per day including associated gas and non-associated gas and the projected production for 2025 will be 8,643.09 million cubic feet per day; a participation in oil and gas sector of 28% up from 21% in 1999.

Recently, through the publication Prospectiva del Mercado de Gas Natural 2002-2011, published by the SENER, the investments program of PEMEX Gas y Petroquímica Básica (PGPB) will increase, substantially, the processing capacity of wet sour and sweet gas produced by PEMEX Exploración y Producción (PEP). Additionally, there are important increments in the cryogenic capacity, the addition of an integral gas processing project for gas from the south region of Burgos, increments in the fractionating capacity of the Coatzacoalcos region and increments in the transport capacity. According to mentioned publication, under the scenario of accelerated development of the natural gas potential, the domestic natural gas production for the period 2002-2011 could be, in average, 7,096 million cubic feet per day with a maximum of 9,000 million cubic feet by the end of 2010. Therefore, if this program of investments comes into reality, the entire picture (Figure 13), in terms of the split of domestic production and imports will change, passing from a natural gas importer to an exporter. Nevertheless,

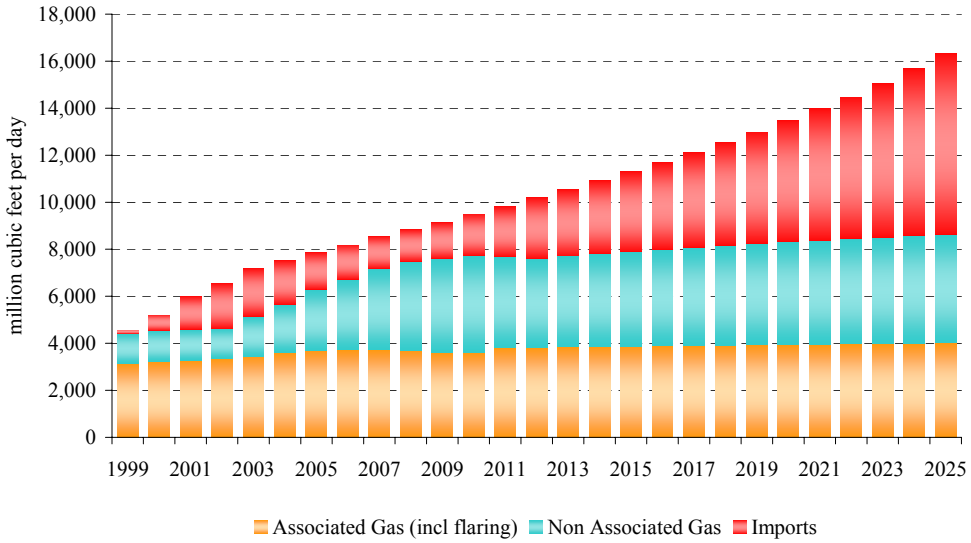

Figure 13. Projected natural gas supply (Reference case)

Coal primary energy supply increases at a 3.7% annual average growth rate, from 272.8 up to 705.4 PJ (Figure 11). Coal data reported in the National Energy Balance spreadsheet account for the coal supply after the washing process of coal (thermal and metallurgical). On the other hand, the coal energy chain and the sector's configuration in the study accounts for the whole energy chain including domestic production

of both types of coal (thermal and metallurgical), transformation losses in the washing process and inventory changes.

For the reference case the power generation by fuel type and total generation for the interconnected system are shown in Figure 14. This case corresponds to the actual natural gas policy in the power sector. For the reference case, that is, no limitation in the natural gas supply the main results for the sector are:

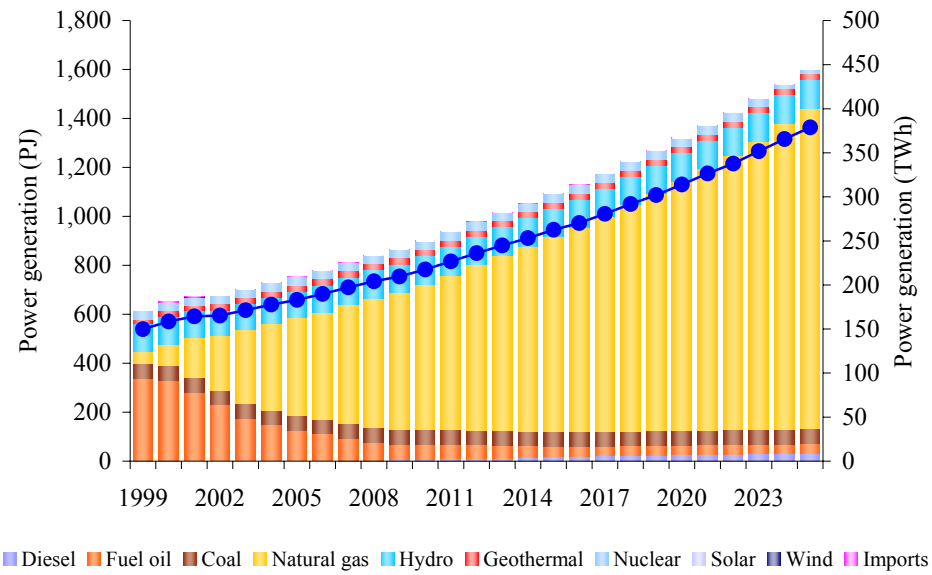

Figure 14. Power generation by fuel type (Reference case)

- Mexico's power sector is expected to undergo significant changes over the forecast period. Model results show a dramatically increasing reliance on natural gas for future system expansion. While Mexico's fuel oil units are either retired or converted to imported coal, natural gas-fired generation increases over 25 times by 2025. The natural gas-fired generation increases from 49.92 PJ (14 TWh) to 1,265.18 PJ (351 TWh) in 2025; natural gas generation share increases from 8.09 to 78.94 percent, meaning an average growth rate of 13.2%.

- Fuel oil fired generation decreases from 332.79 PJ (92 TWh) to 39.39 PJ (11 TWh) in 2025; its share in the total generation decreases from 53.93 to 2.46 percent as a result of the fuel oil reduction policy in the country and the conversion from fuel oil to imported coal of the dual power plants, therefore, coal grows from 60.61 PJ (17 TWh) in 1999 to 105.9 PJ (29 TWh) in 2025 and remains at this level throughout the projection period, however its contribution to the total generation decreases from 9.82 to 6.61 percent.

- Hydro generation increases from 113.77 to 117.24 PJ in 2925, however, its share decreases from 18.43 to 7.32 percent;

- Geothermal generation growths from 19.37 to 24.1 PJ by 2025, its share in the total generation decreases from 3.14 to 1.5 percent;

- Nuclear generation contribution decreases from 34.26 to 17.13 PJ as a result of no nuclear additions and the retirement of unit 1 of Laguna Verde nuclear power plant, its share in the generation decreases from 5.55 to 1.07% by 2025;

- Diesel generation increases from 4.1 to 32.44 PJ with a share in the total generation of 0.66 to 2.02 percent by 2025; and,

- Wind participates in the total generation with a very small amount and a decreasing share of electricity imports from 0.38 to 0.07 percent by 2025.

The Reference Case (Base Case) considers no supply limitation on fuels, no limit on annual inputs of new units, a reserve margin between 10 and 30% and the five hydroelectric projects included in the expansion plan are committed plants, among other assumptions. The power capacity generation expansion shows that the system develops on natural gas; a number of 4 to 7 new combined cycle units are put into operation annually. The optimal solution (Figures 15, 16) shows that the system will require 118 combined cycle unit of 546 MW, 6 gas turbines of 179 MW and 5 hydroelectric projects (2,539 MW). A total of capacity additions of 65.5 GW based on natural gas along the period 2000-2024 (capacity additions for the period 2000-2010 are 26.9 GW, also based on natural gas).

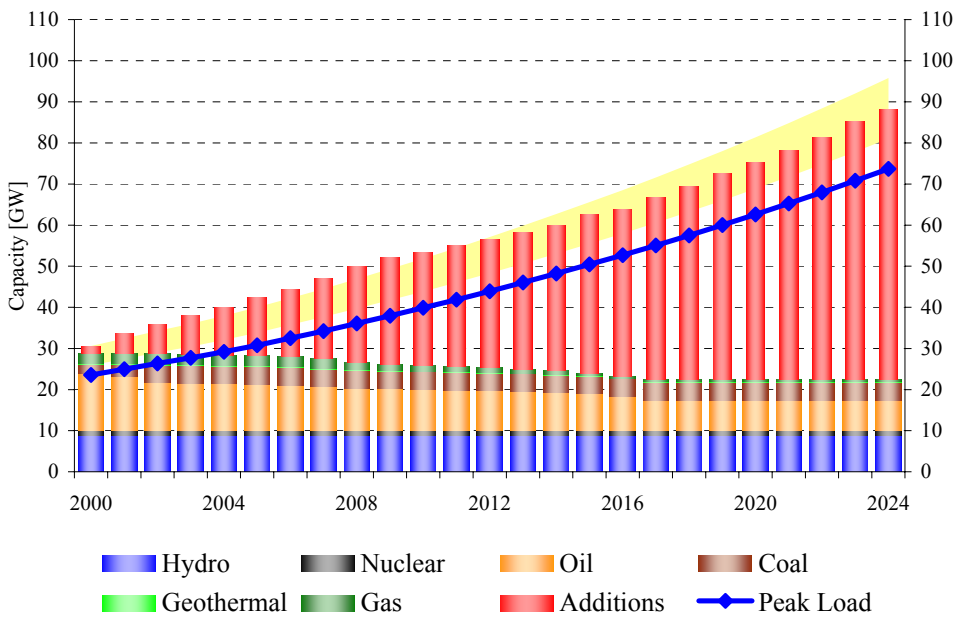

Figure 15. Mexico projected power system development (Reference case)

The heavy dependence on natural gas could be a serious problem in the long term due to: a) in spite of the existing gas reserves in Mexico, there is an uncertainty on the domestic natural gas production in the long term, as well as on the infrastructure required to handle the gas; b) the growing demand of natural gas in the different sectors of the economy; c) the demand growth is bigger than the supply and as a consequence there is a major dependence on gas imports and the uncertainty on gas imports is very high in the long term; d) the variability of international gas prices, and e) the high demand of gas-fired technologies in the international market could be a limitation in the near future, because the new units will be imported.

Since the annual system costs grow proportionally to the increase in the total system capacity, mostly due to the increasing fuel costs, the system would be very vulnerable to the possibility of gas prices increases. During the operation of the system it is assumed a reserve margin between 10 and 30%, the results showed that the system has a reserve margin around 33% in the first 10 years (medium term) and then decreases up to 23% during the next 9 years and reaches 18% in the last years of the period. Finally, the reliability of

the power system in the medium term is very small (0.06 days/year) and reaches a value of 2.72 days/year during the last 6 years of the planning period, which is an acceptable value.

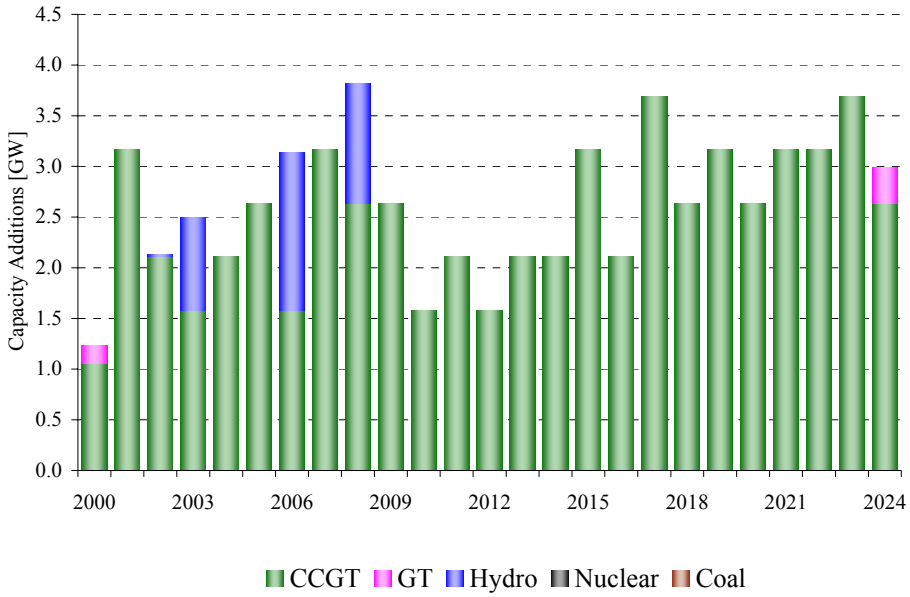

Figure 16. Mexico projected annual capacity additions (Reference case)

A2. Final energy consumption results

Final energy consumption is projected to grow at an average growth rate of 3.8% per year from 4,030 PJ in 1999 to 10,666 PJ by 2025 (Figure 17). All the sectors show a growth in the energy consumption along the period 1999-2025, however with the exception of transport sector, the market share for all sectors shows a drop in terms of its contribution to the total final energy consumption. The main results are as follows:

- The sectors of transport and industry represent, in 2025, more than 90% of the market share of the total final energy consumption. These are the fastest growing sectors;

- Transportation accounts for the highest average annual growth rate (4.9%) from 1,547.1 PJ in 1999 to 5,349.3 PJ in 2025 and its market share rises from 38.4 to 50.2 percent;

- The industrial sector is the second highest energy consumer with a 3.7% average annual growth rate. The industry sector consumed 1,560.7 PJ in 1999 and grows to 3,991.9 PJ in 2025, but its market share drops from 38.7 to 37.4 percent;

- The final energy consumption in agriculture sector increases from 116.9 PJ to 222.1 PJ with 2.5% average annual growth rate, but its market share falls from 2.9 to 2.1 percent;

- The commercial and public sectors consumed 119.4 PJ in 1999 and in 2025 arise to 211.5 PJ with a average annual growth rate of 2.2 percent, but its market share drops from 3.0 to 2.0 percent; and,

- The residential sector shows only a slight growth, an average annual growth rate of 1.01 percent but its market share drops sharply from 17 to 8.4 percent.

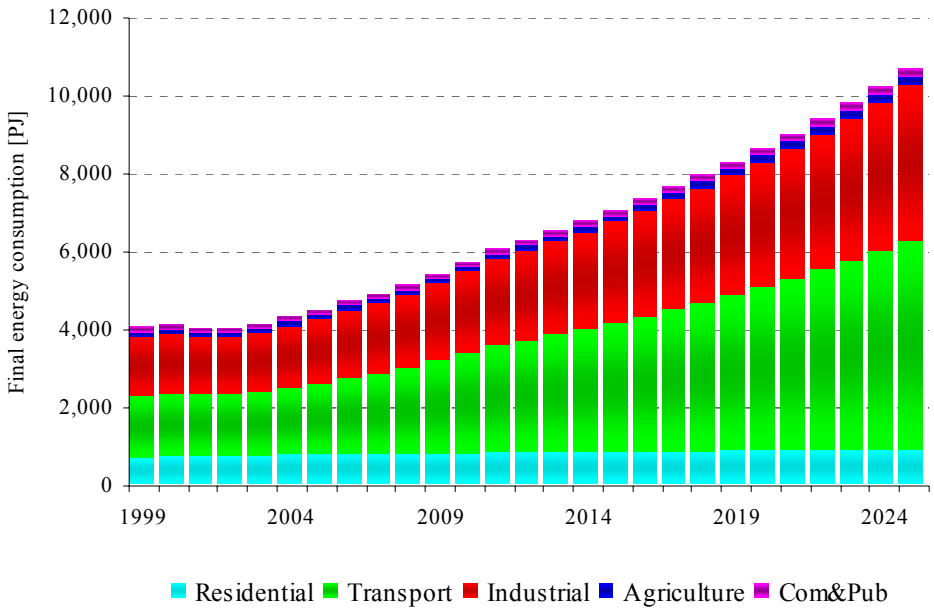

Figure 17. Final energy consumption by sector (Reference case)

As Figure 18 shows, the model projects refined oil products to continue to play a dominant role in Mexico's energy future. The model projects the fuel shares to change as follows over the entire period:

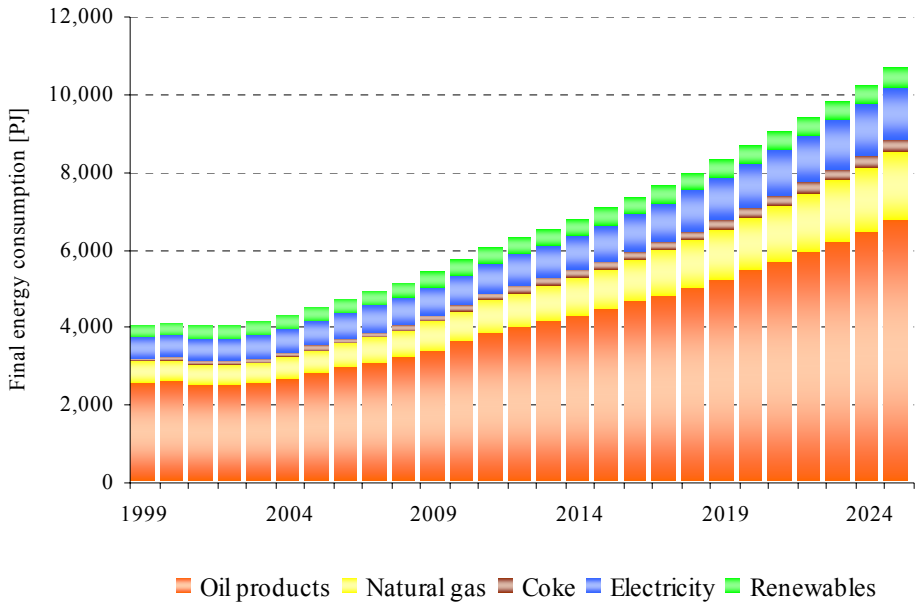

Figure 18. Final energy consumption by fuel (Reference case)

- Coke increase at an average annual growth rate of 4.9 percent from 91.5 to 320.1 PJ (2.3% to 3.0% of market share);

- Oil products grow at an average annual growth rate of 3.9 percent from 2,546 to 6,724.8 PJ and a slightly decrease in market share from 63.18 to 63.05 percent by 2025;

- Natural gas has a high average annual growth rate of 4.8 percent and increases from 526.6 to 1,764 PJ (increase by a factor of 3) and captures 16.5 percent of the market by 2025 (from 13.1% in 1999);

- Electricity growth with an average annual growth rate of 3.7 percent, increasing from 522.0 to 1,353.5 PJ (equal to 145 to 375.6 TWh) while its share rises to 12.7 percent by 2025 (below from 13.0% in 1999). Industrial electricity consumption grows the fastest at 4.6% on average per year while residential electricity consumption is projected to grow at an average of 1.6% between 1999 and 2025; and,

- Renewables grow from 343.88 to 504.0 PJ representing an average annual growth rate of 1.5 percent. Their share falls from 8.5 to 4.7 percent.

According to the actual energy policy, is expected that natural gas will have a substantial penetration in the final end use sectors and in the power sector. Therefore, it results convenient to look, in detail, on the projected increase of this energy fuel along the entire projection period. Total natural gas consumption is projected to increase from 799.4 PJ in 1999 to 4,677.99 PJ by 2025 as shown in Figure 19. The main results are as follows:

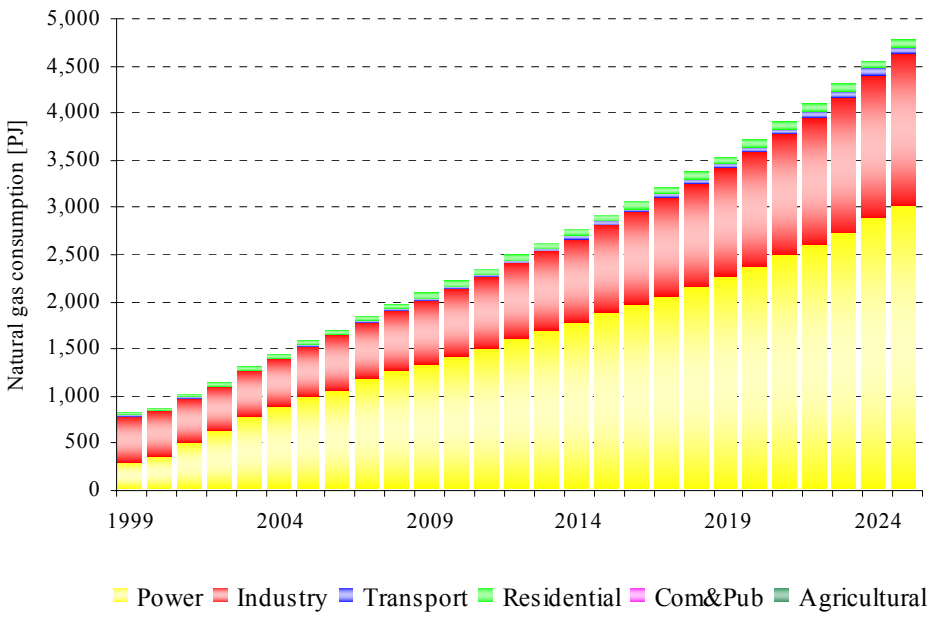

Figure 19. Natural gas consumption by sector (Reference case)

- Industrial sector has a large growth for natural gas accounting for 4.6 percent of total growth. Natural gas consumption increases from 500.4 PJ in 1999 to 1,614.7 PJ in 2025 accounting for 34.5 percent of total gas consumption;

- With 24.3%, transport has the highest average annual growth rate for natural gas consumption of all the sectors during the period 2000–2025;

- Power generation is the second largest contributor to the overall growth in gas demand (34.1%) in 1999 and accounts for 62.3 percent of the total gas consumption in 2025. This represents a 9.54% annual average growth rate along the entire period. Clearly, this is related to the substantial amount of new gas-fired combined-cycle and gas turbine capacity projected to come on-line under the reference case;

The total industrial energy consumption grows at an average annual growth rate of 3.68% from 1,560.70 to 3,991.91 PJ between 1999 and 2025, as shown in Figure 20. Natural gas will continue to be the most important fuel in the industrial sector with almost 40.5% of total energy consumption in 2025. The average growth rate for natural gas is 4.6% per year just below electricity which grows at an average annual growth rate of 4.55% passing from 310.42 to 986.36 PJ in the same period. This represents an increase for electricity in market penetration of almost 5 percent passing from 19.89 percent in 1999 to 24.71 percent in 2025.

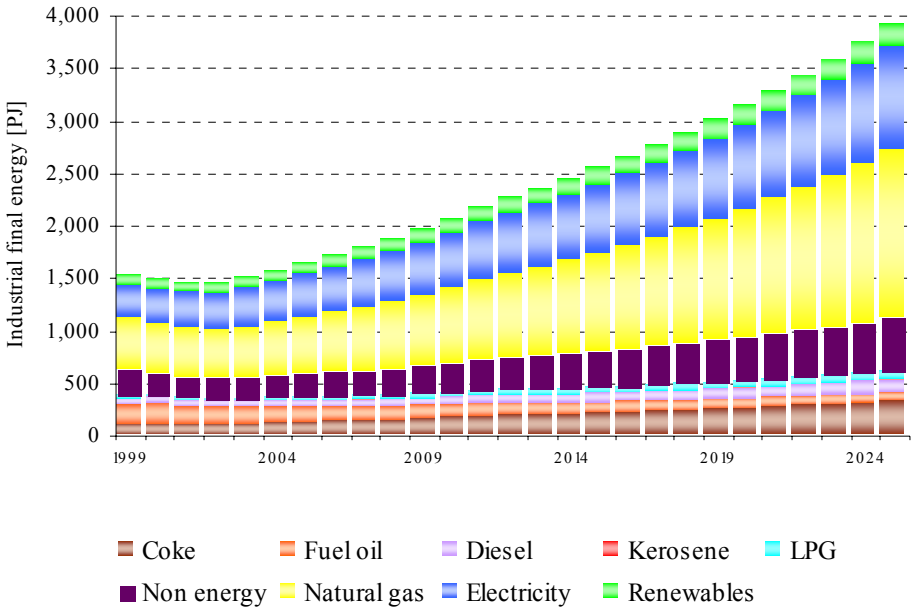

Figure 20. Industrial final energy consumption by fuel (Reference case)

As in the rest of the demand sectors fuel oil will continue its decline in the market from 12.98% in 1999 to 1.98% in 2025 passing in absolute terms from 202.58 to 79.03 PJ. This is in accordance with the current environmental restrictions imposed by the Mexican Government, which impose severe limitations on fuel oil consumption for the industrial and other sectors.

Figure 21 shows the strong growth of the transportation energy demand from 1,547 PJ to 5,349 PJ. Motor gasoline and diesel combined will continue to provide 90% of the total transport energy needs with gasoline accounting for the majority, that is, about 63%. Market shares of transportation fuels are forecast to change very little.

Given the strong growth in transport gasoline demand, Mexico's six refineries are expected to run into their combined capacity constraint around 2005. This drives up the need for gasoline imports from 196 PJ (1999) to 2,276 PJ (2025), a 12-fold increase equivalent to annual growth of 9.9%. By 2025, imports supply 66% of Mexico's gasoline consumption, up from 20% in 1999.

Projected net imports of refined petroleum products are shown in Figure 22. Net imports of refined oil products quickly increase from 215 PJ (1999) to 3,749 PJ (2025). By 2025, net gasoline imports amount to 2,063 PJ or 55% of total net oil product imports. Net diesel imports are forecast to be 1,098 PJ or 29% of total net oil product imports.

Figure 23 shows Mexico's net oil export balance. The graph clearly shows the impact of the projected growth imports of refined product. Crude oil exports are expected to continue their growth at an average

rate of 0.7% per year from 3,396 PJ in 1999 to 4,520 PJ in 2025, net imports of refined products quickly increase and result in a very rapid drop in net oil exports eventually declining to 771 PJ in 2025, down from a peak of 3,848 PJ in 2005.

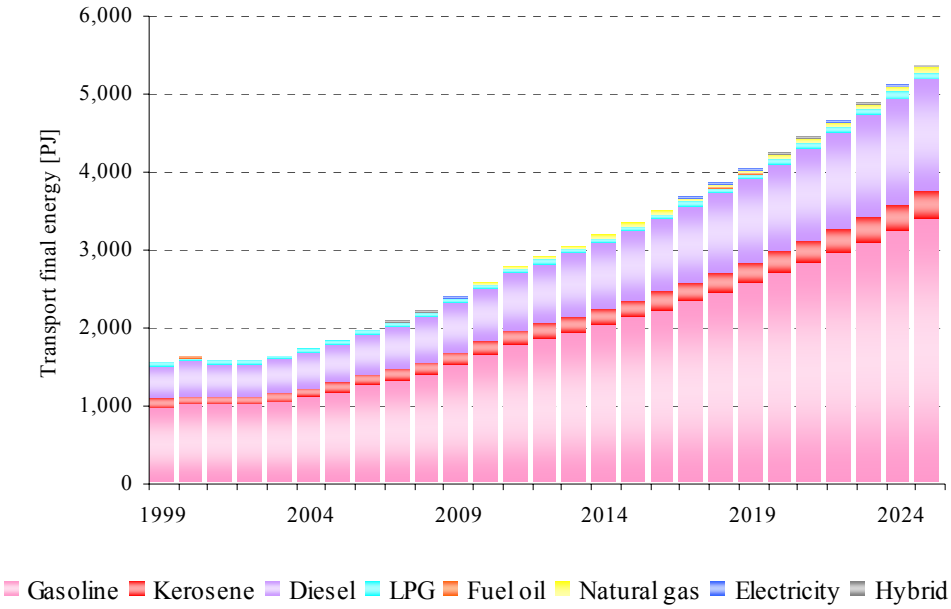

Figure 21. Transport final energy consumption (Reference case)

In addition, the study did not attempt to investigate different sources of import gas or whether it will be in the form of liquefied natural gas (LNG) and where these LNG terminals will likely be located. Undoubtedly though, if Mexico will not be able to close the projected gap between supply and demand either in form of additional domestic supplies or new imports, it might be exposed to price volatility similar to what has been observed in the U.S. recently (Greenspan, 2003) or risk disruptions in its gas markets.

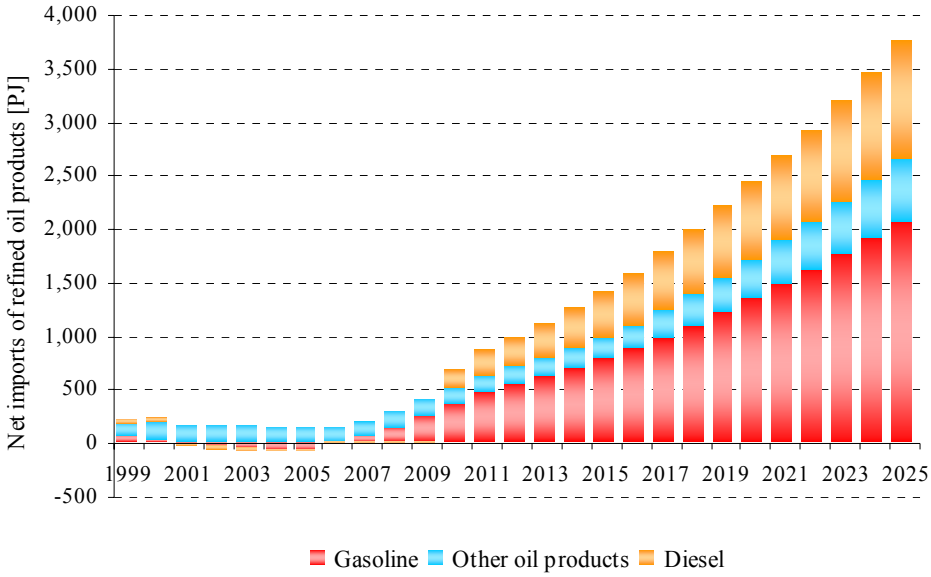

Figure 22. Net imports of refined oil products (Reference case)

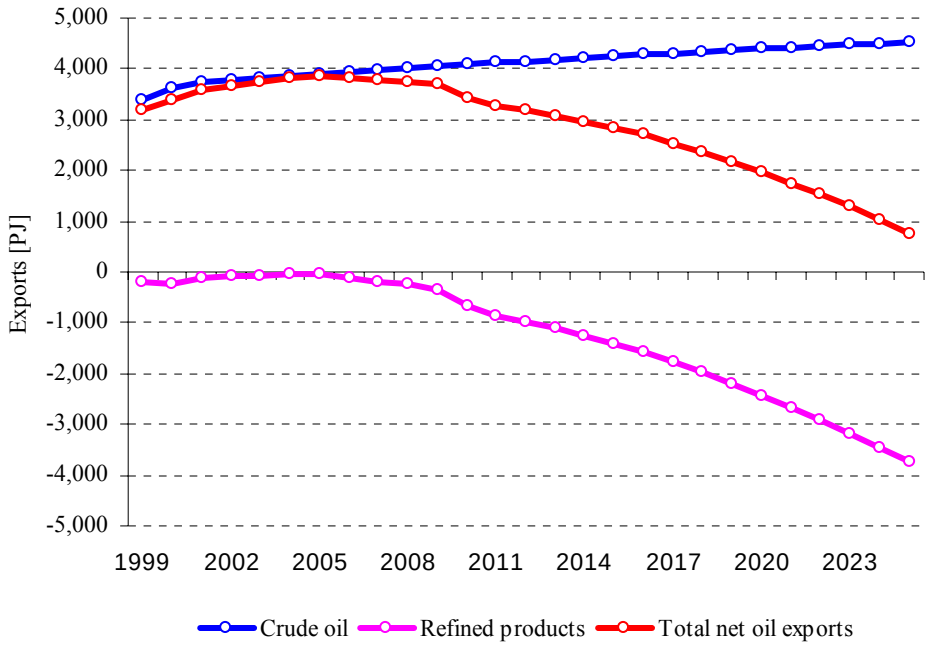

Figure 23. Net oil export balance (Reference case)

A3. CO_2 emissions

Total CO_2 emissions (Figure 24) increase at an average annual growth rate of 3.41% from 346.1 million ton in 1999 to 828.41 million ton per year by 2025. The most noticeable change in sectoral contribution comes from the transport sector whose emissions grow by 4.87% per year and account for 44.73% of the total CO_2 emissions in 2025 (370.56 million ton), up from 31.8% in 1999 (107.57 million ton). This is driven by the high growth in transport final energy from gasoline and diesel fuels. These fuels account for 90.12% of transport final energy consumption by 2025, despite the increased penetration of natural gas and LPG.

Electric sector CO_2 emissions grow at a below average rate of 2.63% per year, mostly due to the increasing reliance on natural gas. Also, there is a contribution from imported coal for the dual plants substituting fuel oil. The annual power sector CO_2 emissions increase from 98.19 million ton in 1999 to 193.07 million ton by 2025. The power sector contribution slowly declines from 1999 to a low point of 93.15 in 2005, and then increases again up to the 2025 value.

On the other hand CO_2 emissions for some of the sectors grow at average annual growth rates below average annual growth rate for the entire energy system, specifically:

- *Industrial sector,* from a 16.85% share (58.31 million ton) in 1999 to a share of 17.8% (147.48 million ton) in 2025; an average annual growth rate of 3.63%; this sector shows a slight declination in its share from 1999 to a low point of 53.81 million ton in 2002, and then increases again up to the value in 2025;

- *Supply sector,* 15.06% share (52.13 million ton) in 1999 to 8.71% (72.14 million ton) in 2005; an average annual growth rate of 1.26%; even that the sector shows an increasing emissions pattern its share to the total emissions decreases systematically after 2003;

- *Residential sector,* 5.67% share (19.62 million ton) in 1999 to 3.3% (27.37 million ton) in 2025 and an average annual growth rate of 1.29%. This sector also shows, in absolute terms, an increasing emissions pattern but its share to the total emission decreases systematically after 2003; this behavior could be explained in terms of two aspects, one related to energy mix and the other to the lower growth rate of the population.

- *Agriculture sector,* 1.86 percent (6.43 million ton) in 1999 to 1.52 percent (12.56 million ton) in 2025 and an average annual growth rate of 2.61 percent; and,

- *Commercial and Public sector,* 1.11% share (3.84 million ton) in 1999 to 0.63% (5.22 million ton) in 2005 and an average annual growth rate of 1.19%.

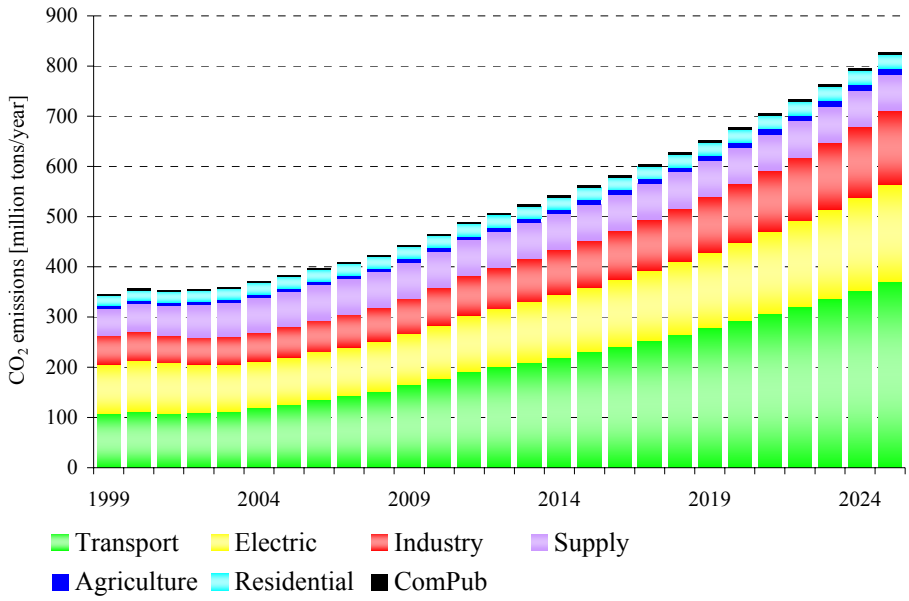

Figure 24. CO_2 emissions by sector (Reference case)

As a general result for all the sectors, the decreasing pattern of energy consumption and associated emissions in the years 1999-2003 is a result of the low economic growth of the whole economy.

A4. NO_X emissions

As shown in Figure 25, national NO_X emissions are expected to grow at an average rate of 4.37% per year from 1.52 to 4.61 million ton over the period 1999 to 2025. The transport sector is the largest contributor, 66.84% in 1999 (1,013.59 thousand ton) and 73.62% in 2025 (3,392.1 thousand ton) of total NO_X emissions, which implies a 234.66% increase for the projection period.

The power sector NO_X emissions are expected to grow at 4.28% average annual growth rate passing from 281.85 thousand ton in 1999 to 837.41 thousand ton by 2025, this means an increase of 197.11% along the period.

The industrial sector also shows an important increase, 137.96% along the period, with an average annual growth rate of 3.39% and absolute values of 82.79 thousand ton in 1999 and 197.01 thousand ton by 2025.

The agricultural sector emissions grow at an average annual growth rate of 2.61% passing from 5.99 thousand ton in 1999 to 11.69 thousand ton by 2025, which means an increase of 95.17%.

The supply sector emissions of this pollutant also increase from 82.89 thousand ton in 1999 to 110.85 thousand ton by 2025 with an average annual growth rate of 1.12%.

The commercial and public sector emissions increase at an average growth rate of 1.19%, from 4.26 thousand ton in 1999 to 5.79 thousand ton by 2025, a 35.9% increase in 2025 with respect to 1999. The residential sector increase its emissions at an average annual growth rate of 0.61%, 44.99 thousand ton in 1999 and 52.71 thousand ton by 2025, a 17.16% increase.

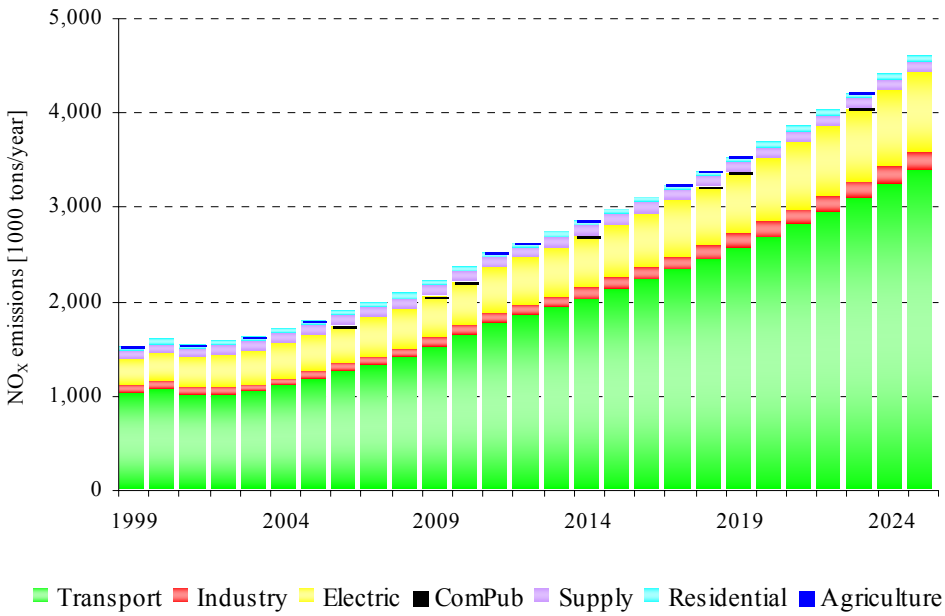

Figure 25. NO_X emissions by sector (Reference case)

A5. SO_2 emissions

Figure 26 shows the projected SO_2 emissions that exhibit a marked reduction of about 24% from 1999 to 2025. Emissions are forecast to initially decline from 2.35 million ton (1999) to a low of 1.21 million ton (2008) and then gradually increase again to 1.78 million ton (2025). The most noticeable change is the substantial drop in power sector emissions from 1.71 million ton (73% of the total) in 1999 to 0.38 million ton (22% of the total) in 2025. This behavior is linked to the retirement of several of fuel oil units burning high-sulfur fuel oil, the conversion of some of the fuel oil units to low-sulfur imported coal plants, as well as the projected dramatic switch to natural gas for power generation with essentially zero SO_2 emissions.

The gradual increase in national SO_2 emissions after 2008 is related to the rise in industrial SO_2 emissions that grow on average at about 3.4% from 0.44 million ton in 1999 to 1.07 million ton in 2025 as the sector continues to burn high-sulfur fuel oil. This causes the manufacturing sector to become the largest source of SO_2 by the end of the analysis period, that is, 60% as compared to 19% in 1999.

A6. PM emissions

The projected emissions of particulate matter (PM) are shown in Figure 27. It can be said that the behavior is somewhat comparable with the previous discussion in that emissions initially decline from 323 thousand ton (1999) to 280 thousand ton (2003) and then increase to 484 thousand ton by year 2025. However, the drop in power sector PM emissions is not nearly enough to offset the continued emissions growth in the other sectors, therefore leading to an overall increase in the PM emissions. While power

sector PM emissions decline from 92 thousand ton (29% of total, largest PM source) in 1999 to 4% of the total that is 19 thousand ton in 2025. The emissions of the transportation and industrial sectors continue to grow. By 2025, transportation is the largest PM source with 208 thousand ton or 43% of the total (up from 60 thousand ton or 18% of the total in 1999).

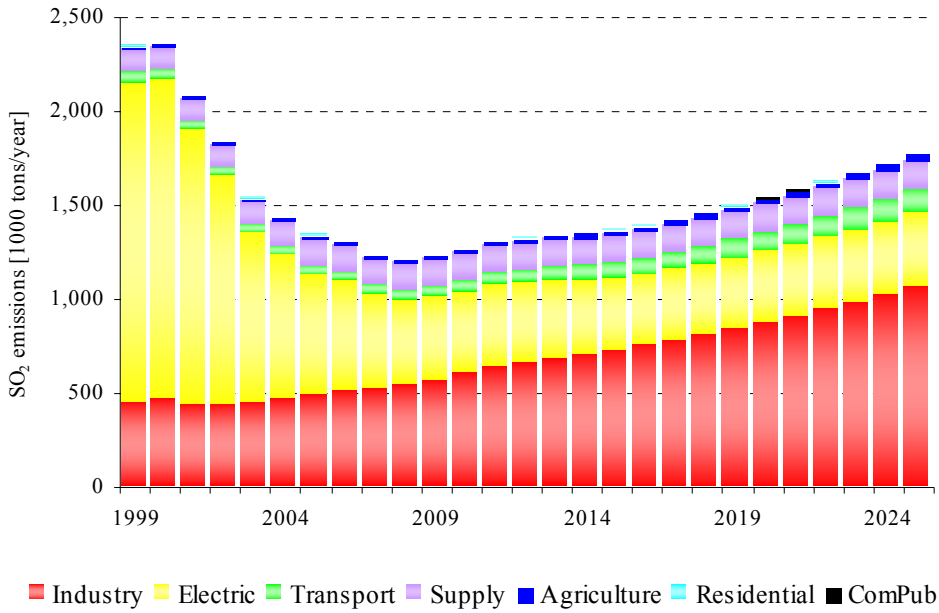

Figure 26. SO_2 emissions by sector (Reference case)

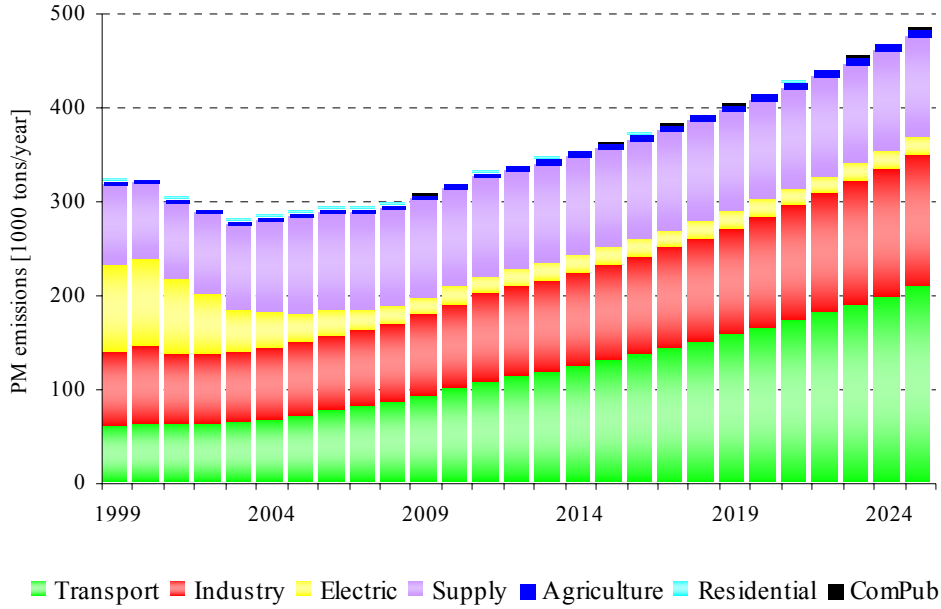

Figure 27. PM emissions by sector (Reference case)

B. Limited natural gas supply scenario results

B1. Energy results

As a result of the limitation in gas supply, the expansion of the power sector changes substantially. Starting in 2009, the expansion model (Figure 28) selects the maximum of 3 combined cycle units each year instead of 3 to 7 units per year under the reference case. The cumulative number of combined cycle units under the limited gas scenario totals 85 (44.8 GW) as compared to 118 units (62.2 GW) under the reference case. From 2009 up to 2013, even that there are 4 combined cycle units less than in the reference case, the new coal units are not needed until 2014. Starting in 2014, the model projects between 4 and 6 coal-fired units to come on-line each year, with a total of 57 coal units or 17.7 GW.

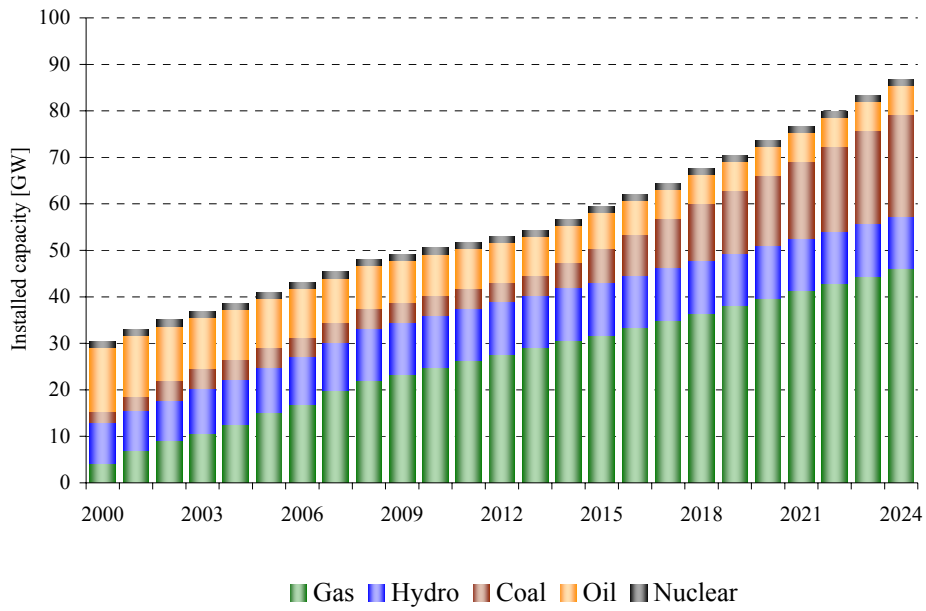

Figure 28. Projected installed capacity
(Limited natural gas scenario)

The effect on generation by fuel type can be seen in Figure 29. It is noteworthy that while the gas limitation becomes effective in 2009, the generation results don't show a significant difference until 2014. This is the year when the WASP/DECADES software projects the first coal-fired units to come on-line.

Correspondingly, coal generation starts to increase quickly from 106 PJ (29 TWh) in 2013 to 572 PJ (159 TWh) by 2025 and account for 36% of total power generation. The increased coal generation essentially replaces up to 470 PJ of gas-fired generation by 2025 (Figure 30). The share of natural gas generation, therefore, reaches only about 50% as compared to 79% under the reference case.

The lower gas generation noticeably slows the growth in total gas consumption. Gas consumption is expected to grow to 3,710 PJ, down from 4,769 PJ in the reference case. This reduction of 968 PJ or 21% is essentially because of reduced power sector gas demand as shown in Figure 31. While under the reference case, the power sector accounts for about 68% of total natural gas demand, under the limited gas scenario, this is down to 53%. In response to the reduction in gas demand for power generation, the need for natural gas imports declines. While approximately 2,690 PJ of gas has to be added or imported in the reference case by 2025, imports are down to 1,781 PJ in this scenario.

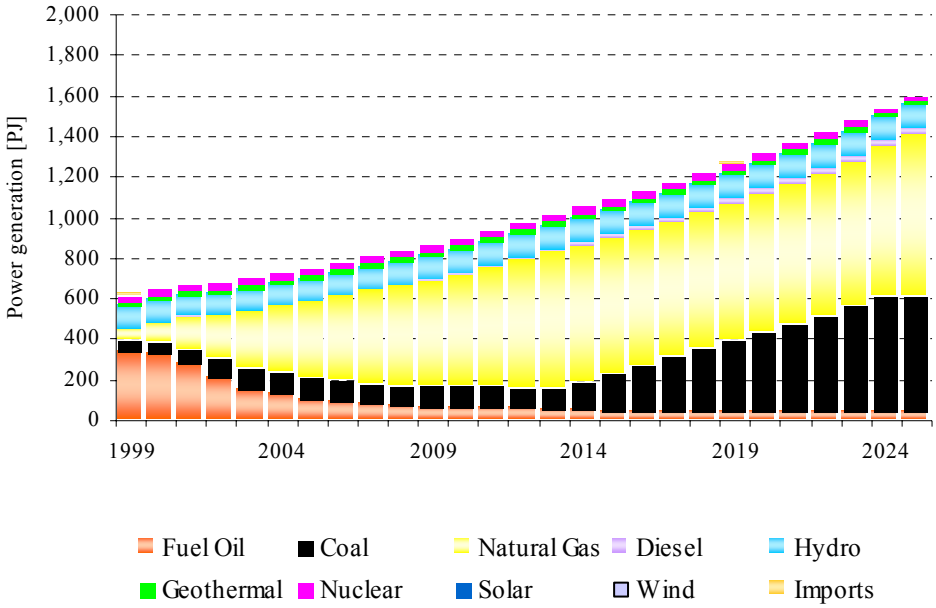

Figure 29. Generation by fuel type
(Limited natural gas scenario)

The additional coal-fired generation cannot address (Figures 32 and 33) the near to intermediate-term natural gas needs. Additions/imports are substantially reduced only starting in 2014. The decrease of 909 PJ by 2025 is equivalent to a 34% reduction of natural gas imports.

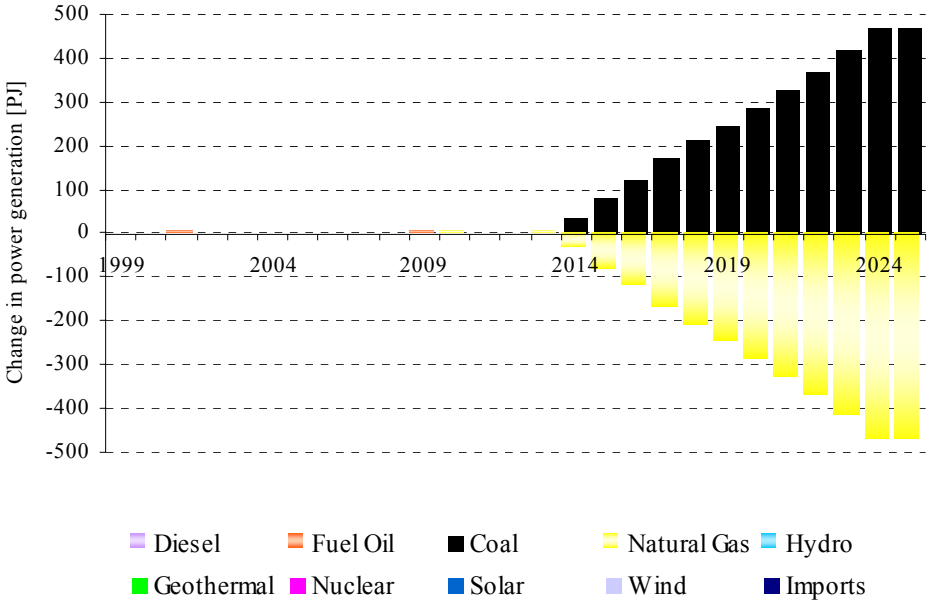

Figure 30. Change in generation by fuel type
(Limited natural gas scenario – Reference case)

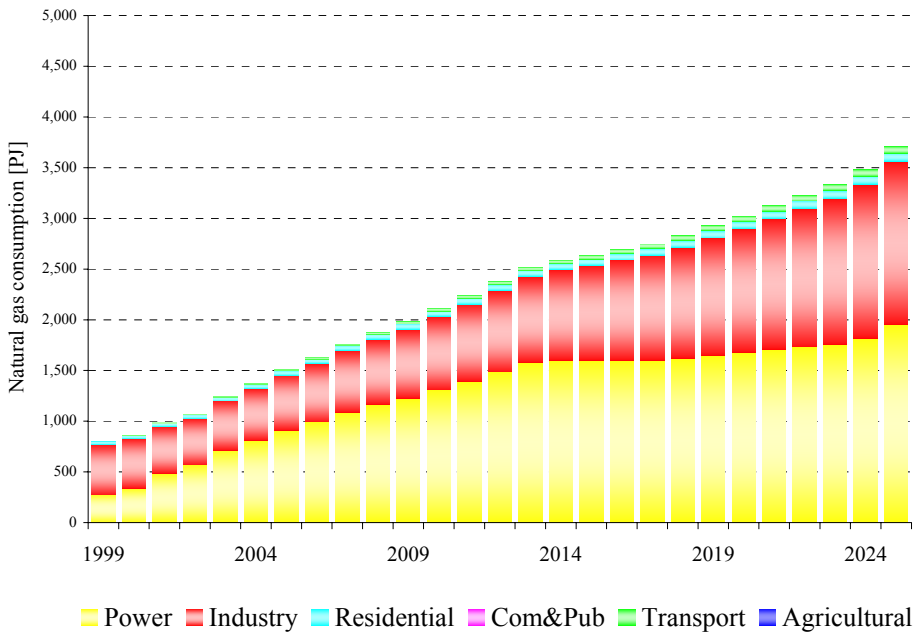

Figure 31. Natural gas consumption by sector
(Limited natural gas scenario)

At US$709.58 billion in net present value, total economic system cost is higher than under the reference case, that is, the limitation on natural gas supply comes at an economic cost, in this case estimated to be an incremental cost of US$2.17 billion.

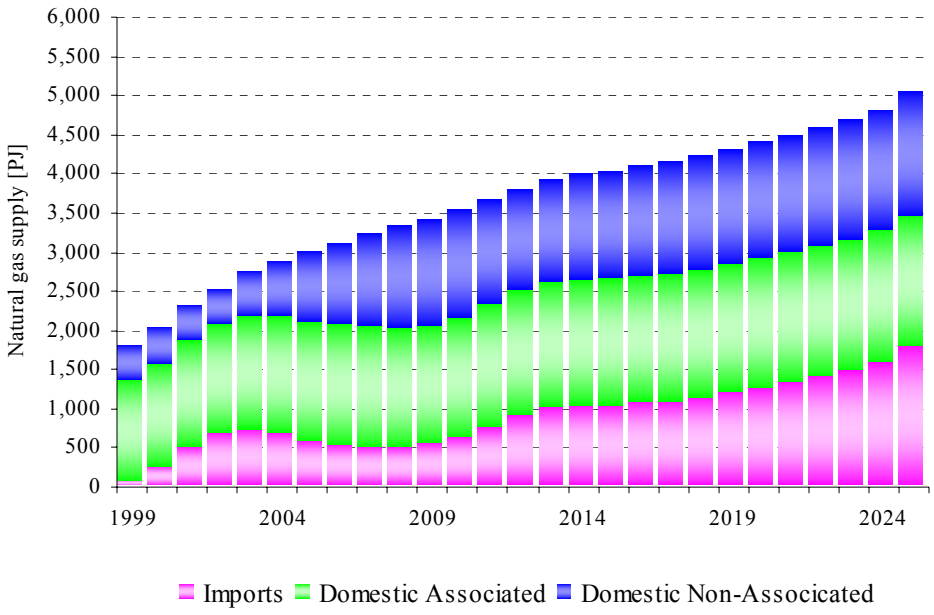

Figure 32. Natural gas supply
(Limited natural gas scenario)

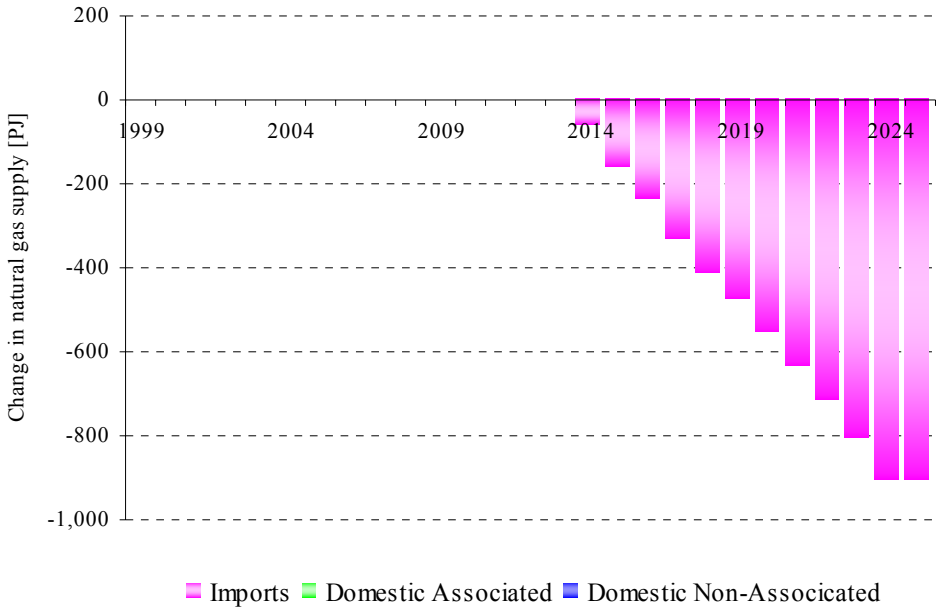

Figure 33. Change in natural gas supply
(Limited natural gas scenario – Reference case)

B2. Emissions results

Not surprisingly, the shift from gas to coal comes at an environmental cost. Atmospheric emissions are projected to increase under the limited gas scenario. Figure 34 shows, for example, the changes in CO_2 emissions compared to the reference case. Under the limited natural gas scenario, the power sector emissions grow to 238.69 million ton of CO_2 emissions while total national emissions reach 874.26 million ton. This is an increase of about 45.62 million ton over the reference case, equivalent to a 23.63% increase in power sector emissions or the 5.22% of national CO_2 emissions.

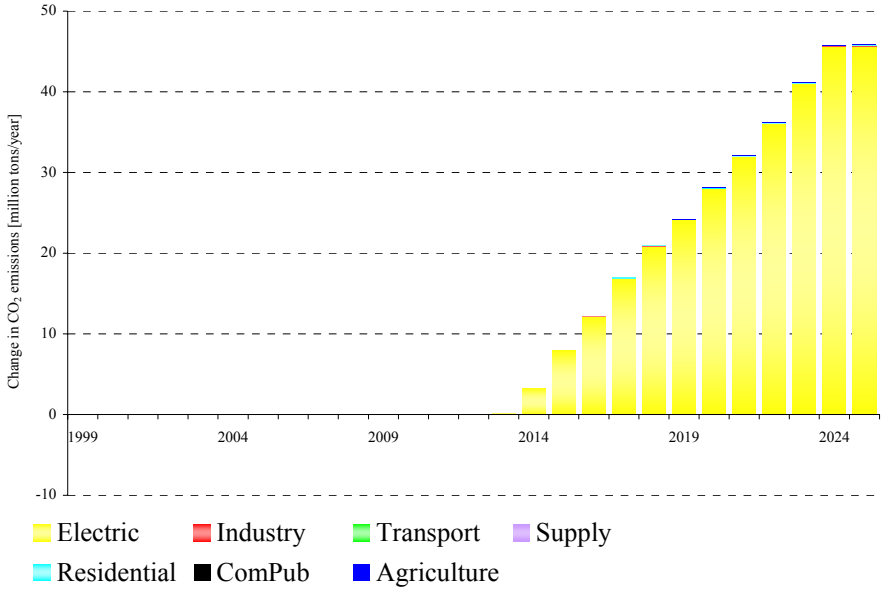

Figure 34. Change in CO_2 emissions
(Limited natural gas scenario – Reference case)

Emissions of NO_X exhibit a similar behavior in that power sector emissions (Figure 35) are forecast to reach about 989,590 ton by 2025, which is about 152,180 ton or 18.17% higher than under the reference case in 2025. For details on the results for the emissions of SO_2 and PM see Quintanilla et al. (1999, 2003).

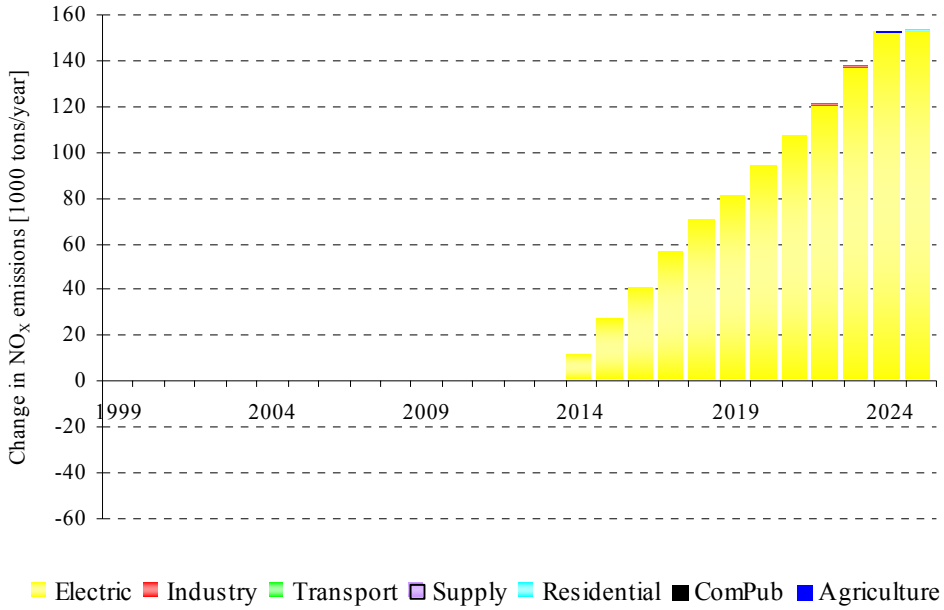

Figure 35. Change in NO_X emissions
(Limited natural gas scenario – Reference case)

Under the limited natural gas scenario, the rest of the considered economic sectors do not present changes in their contribution to the NO_X emissions when compared with the reference case.

B3. Natural gas price sensitivity analysis

In view of the present energy policy of high penetration of natural gas in all energy and economic activities, it was considered useful to analyze alternative plans for the expansion of the power sector by taking different future projections of the natural gas prices with the purpose of evaluating their impacts on the electricity generation system.

Considering just the power sector, the following three alternative expansion plans were analyzed, looking at their investment and fuel costs, capacity expansion and environmental impacts:

- **Alternative NG_1:** Case of slightly higher fossil fuel prices
- **Alternative NG_2:** Case of a medium term increase in the gas price
- **Alternative NG_3:** Case of notably higher gas prices

For the alternative NG_1, the initial fuel prices in this case are the same as those in the reference case, except for the natural gas price which is 2.96 US$/tcf instead of 2.88 US$/tcf. This case considers the same assumptions on the supply side as those for the reference case except for the difference in the scenario of fuel prices. In this alternative the additional capacity is almost the same as that in the reference

case. This case assumes the construction of one additional combined cycle unit and two gas turbines less by 2024 than in the reference case. The share of electricity generation is practically the same as in the reference case.

Alternative NG_2, assumes that the natural gas price is 4.02 US$/tcf in the base year instead of 2.88 US$/tcf as in the reference case. Practically, the natural gas price remains around 4 US$/tcf over the planning period. The remaining assumptions are the same as in the reference case. It may be noted that the gas fired capacity is about 65,430 MW (110 combined-cycle units and 30 gas turbine units) which is essentially identical, in terms of total capacity, as that in the reference case. The unique differences in this alternative expansion plan are eight combined cycle 546 MW units less and 24 GT-179 MW units more than in the reference case. The share of natural gas fired capacity and the other capacities are the same as those in the reference case.

Alternative NG_3 assumes that the natural gas price is increased from 2.88 US$/tcf in 1998 up to a peak of 12 US$/tcf in 2010 and then it declines to 4 US$/tcf in 2024. Figure 36 shows the escalation of the natural gas price for this alternative plan. Due to this higher price scenario for natural gas it may be noted that the additional coal fired capacity is incremented to 55,650 MW as compared to non-coal capacity in the reference case, whereas the additional natural gas fired capacity is only 14,912 MW as compared to about 65,500 MW in the reference case. This alternative assumes that 159 dual units of 350 MW based on coal, 26 combined cycle units of 546 MW and four gas turbines units of 179 MW will be constructed, whereas hydroelectric capacity remains the same as in the reference case.

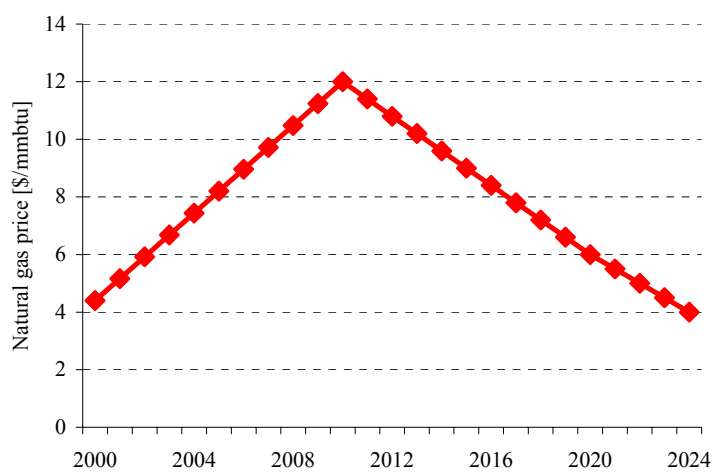

Figure 36. Natural gas price scenario

The capacity additions and the projected installed capacity for this case are shown in Figures 37 and 38. The impact of the natural gas price and its future projection is high because the share of natural gas fired capacity has significantly decreased from 73% in the reference case to 17%, while the share of coal fired capacity grew from 0% in the Base Case to 61% in this alternative. Due to the efficiency of dual plants about 5 060 MW of additional capacity is required in the optimal solution compared with that in the reference case.

The comparison in present value of the investment requirements for power generation of the reference case and Alternatives NG_1, NG_2 and NG_3 shows the following results. Compared to the reference case the total cost for Alternative NG_1 is 8% higher than the total cost for the reference case. In the case of Alternative C_2 the cumulative investment cost decrease a little bit due to the lower capital costs for gas

turbines compared to those for combined cycle units. The cumulative investment cost in this alternative is 7% lower than in the reference case. It may be noted that compared to the reference case the cumulative operation cost is 21% higher. This represents an increment of 16% in the total cost with respect to the reference case mainly because of the fuel costs.

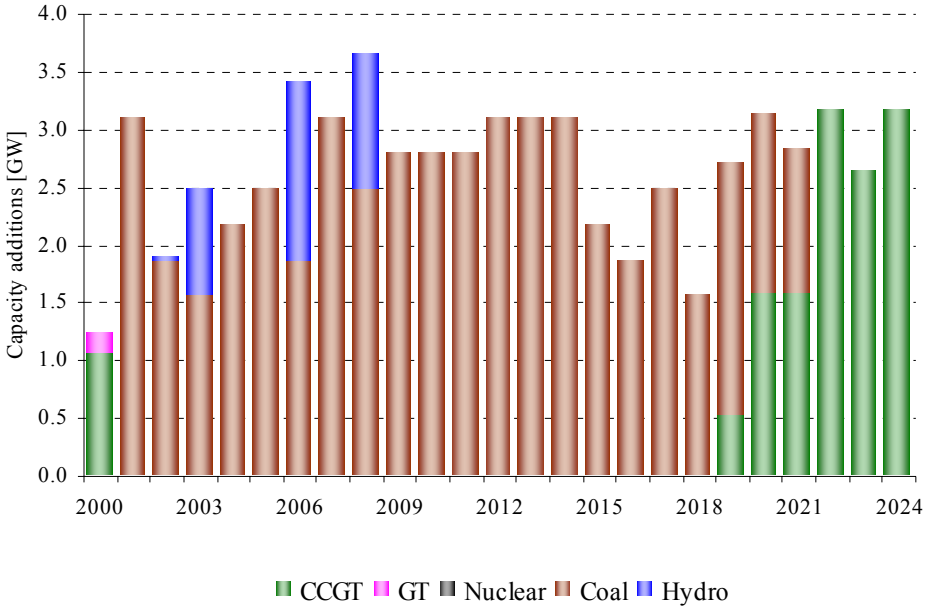

Figure 37. Projected annual capacity additions
(High natural gas price scenario (Alternative NG_3))

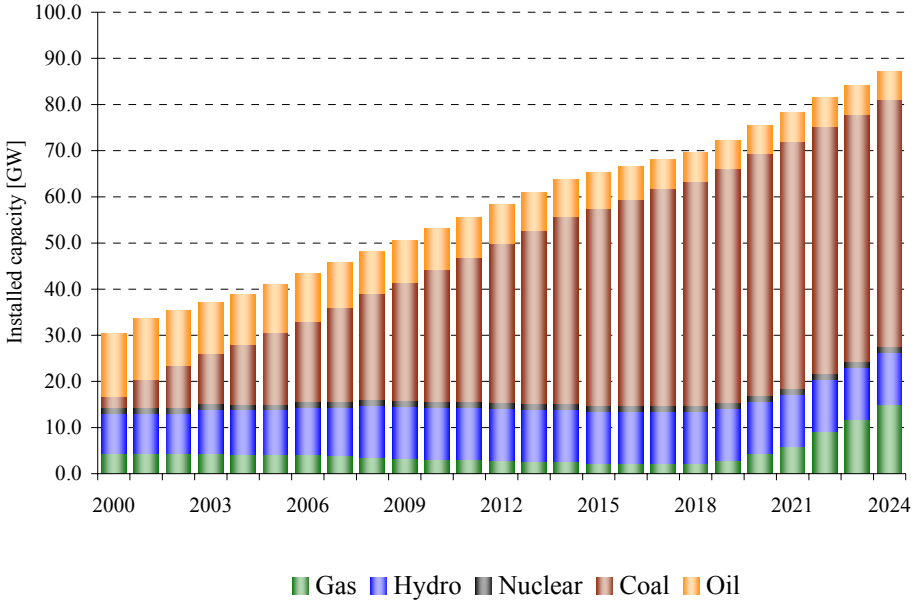

Figure 38. Projected installed capacity
(High natural gas price scenario (Alternative NG_3))

In this sensitivity analysis Alternative NG_3 assumes a higher scenario for natural gas prices and for this reason the optimal solution is totally different with respect to new capacities and investment requirements. Compared to the reference case the total cost for this case is 46% higher.

For the reference case and the Alternatives NG_1, NG_2 and NG_3, the annual environmental emissions from power generation for selected years (2010 and 2024 with respect to the year 1998 emissions) show the following results. It may be noted that the annual emissions of CO_2 and NO_X in reference case will increase by 138% and 53%, respectively, over the study period, while the emissions of SO_X and particulate will decrease by 78% and 83%, respectively, over the same period.

For Alternative C_1, the annual emissions of CO_2 and NO_X will increase by 138% and 52%, respectively, over the study period, while the emissions of SO_X and particulate will decrease by 78% and 84%, respectively, over the same period.

For Alternative C_2, the annual emissions of CO_2 and NO_X will increase by 143% and 68%, respectively, over the study period, while the emissions of SO_X and particulate will decrease by 51% and 55%, respectively, over the same period. Finally, for Alternative C_3, the annual emissions of CO_2 and NO_X will increase by 293.6% and 81.44%, respectively, over the study period, while the emissions of SO_X and particulate will decrease by 59.04% and 37.94%, respectively, over the same period.

C. Nuclear scenario results

C1. Energy results

In this case we consider two scenarios, a forced nuclear introduction and a low nuclear cost.

In the first nuclear scenario, forced nuclear introduction, we forced the introduction of a nuclear power plant of 1,356 MW in the expansion of the power system in order to see the possible non-economical advantages of this additional nuclear power plant. Specifically, we were interested in the advantages of lower emissions or a more diversified power system, and its impact on the system cost.

In the second nuclear scenario, low nuclear cost, the investment cost of a new nuclear power plant is assumed to be 48% lower than in the reference case, allowing new nuclear power plants to appear in the WASP's optimal solution.

For the forced nuclear scenario, because of the large capacity of the nuclear unit, the expansion schedule is slightly affected starting in 2001 even though the unit is not coming on-line until 2012. This leads to some minor changes in generation and fuel consumption in the power sector between 2001 and 2011 as presented in Figure 39. Specifically, from 2001 up to 2011 there is an additional participation of fuel oil generation, which decreases along the years and ends by 2011; hydro also participates with an additional generation, but its participation is just during the year 2001; also there is a declining reduction in the participation of natural gas in the generation along those years.

During the years 2009 to 2011 the fuel type mix in the power generation keeps the reference case structure. When the nuclear unit does come on-line, it is base-loaded into the system and generates a constant level of 34 PJ of electricity per year equivalent to 1.5% of total generation in 2025 as compared to 1.1% under the reference case. The system-level analysis shows that nuclear replaces effectively base-loaded gas combined-cycle capacity and between 33-37 PJ of gas-fired generation.

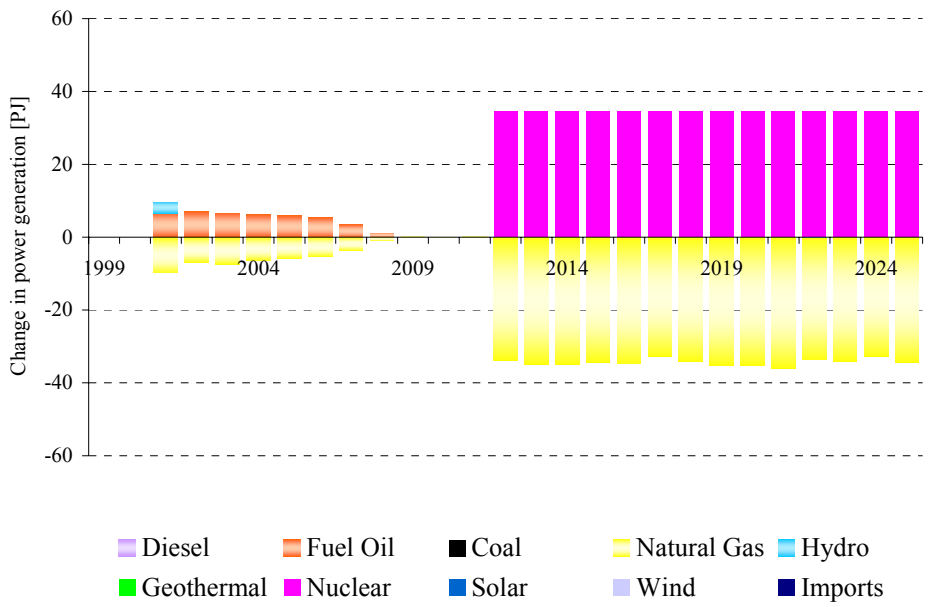

Figure 39. Change in power generation by fuel type
(Forced nuclear introduction scenario- Reference case)

The impact on the supply side is presented in Figure 40. As with the previous scenarios, the shift away from gas-fired generation leads directly to a reduction in natural gas imports. In this case, gas imports are cut by 63-71 PJ or 2.3 percent by 2025.

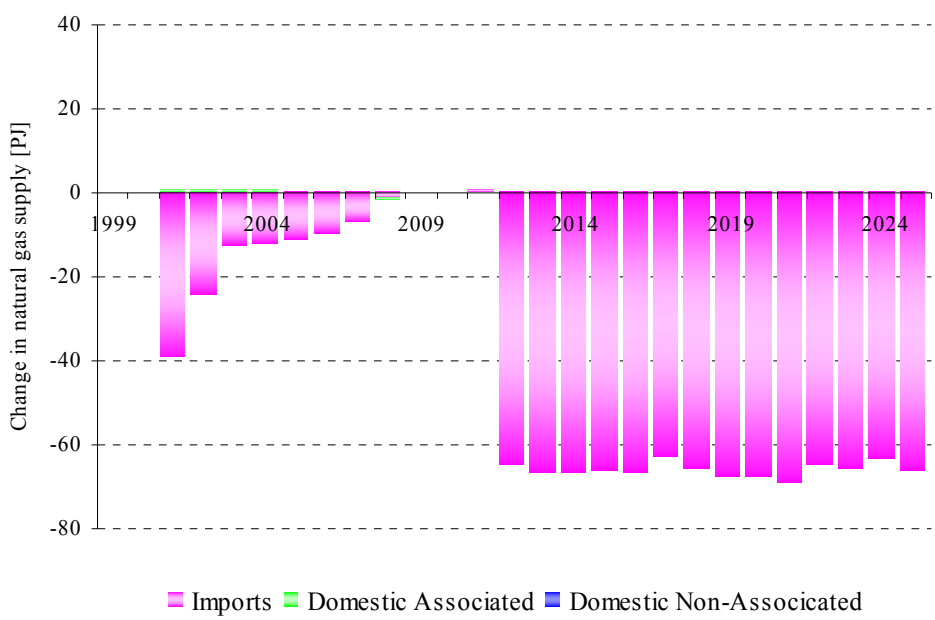

Figure 40. Change in natural gas supply
(Forced nuclear introduction scenario – Reference case)

At US$707.69 billion in net present value, total economic system cost is higher than under the reference scenario, that is, an incremental cost of US$273.4 million.

For the low nuclear costs scenario, it has been assumed that the investment cost of a new nuclear power plant is 48% lower than in the reference case. In this condition new nuclear power plants are competitive with the rest of the candidate technologies for expansion.

It may be noted that in this case five new nuclear power plants of 1,356 MW appeared, with 13 combined cycle plants less than in the reference case and three additional gas turbine plants than in the reference case. The coal, hydroelectric and geothermal capacities are the same as those in the reference case.

With the new nuclear capacity of 6,780 MW the share of nuclear power capacity it will be increased from 1.5% in the reference case to 9% while the share of gas based capacity will decrease from 73% in the reference case to 66% in this alternative case. The capacity additions due to the reduction in nuclear capital costs to the point where nuclear enters the market are shown in Figure 41 and the projected installed capacity for the low nuclear costs scenario is shown in Figure 42.

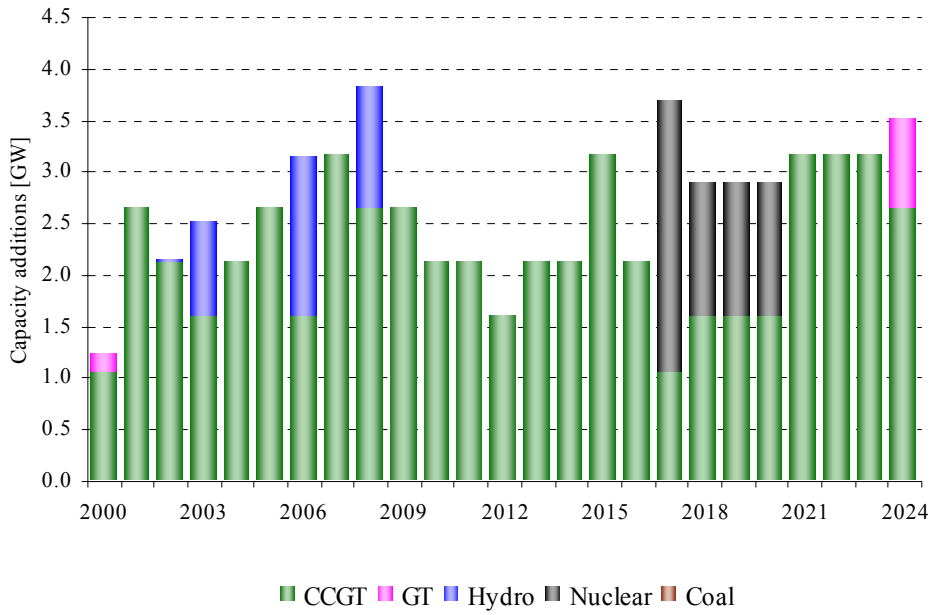

Figure 41. Low nuclear costs scenario (capacity additions due to the reduction in nuclear capital costs to the point where nuclear enters the market)

On the other hand, the comparison of costs in present value for the reference case and the low nuclear costs scenario shows that, because the investment cost for new nuclear power plants is 48% lower than in the reference case, the total cumulative costs are very similar.

C2. Emissions results

The minor changes in dispatch in the early years lead to small emissions increases of up to 1.2 million tons per year in 2003. But emissions are noticeable reduced starting in 2012 when the nuclear unit eventually comes on-line. For example, CO_2 emissions reductions are shown in Figure 43 and vary between 3.6 and 4.0 million ton per year, equivalent to a 1.9% reduction in power sector emissions and a 0.4% reduction in national emissions. Total cumulative emissions reductions are 47.5 million ton of CO_2. The cost-effectiveness of nuclear technology as a GHG mitigation technology is therefore US$5.8/ton CO_2.

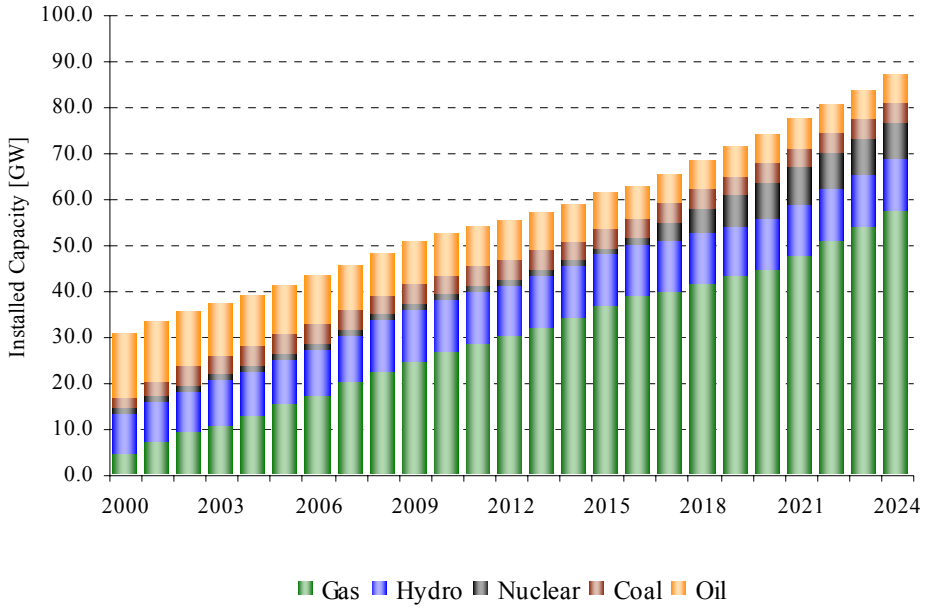

Figure 42. Projected installed capacity
(Nuclear cost reduction scenario)

A similar behavior is exhibited by NO_X emission as shown in Figure 44. Annual reductions vary between 15,000 ton and 17,000 ton of NO_X. In 2025, this represents a 1.9% decrease in power sector NO_X emissions and a 0.3% decrease of total national NO_X emissions. This corresponds to a cumulative emissions reduction of 228 thousand ton. The emissions of the rest of the economic sectors do not present changes as compared to the reference case.

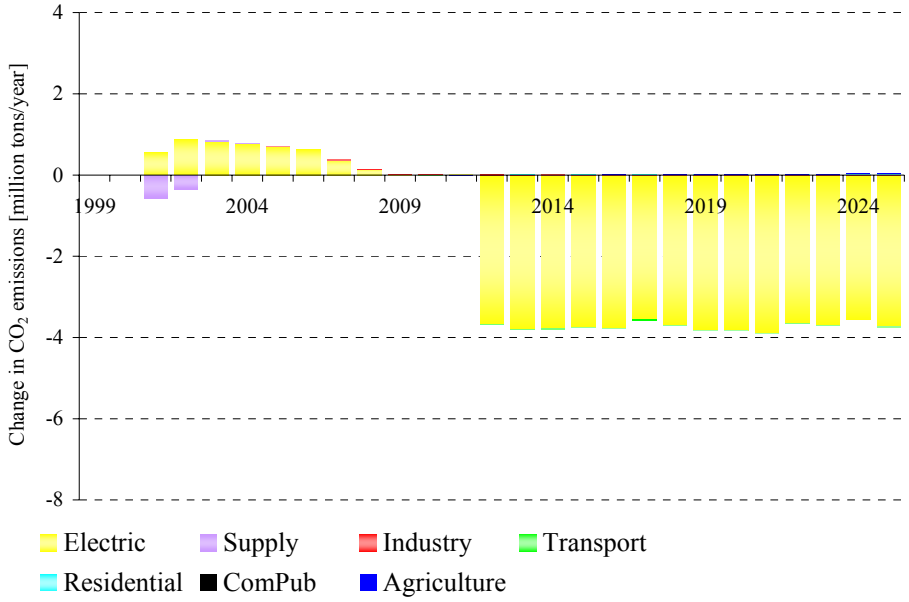

Figure 43. Change in CO_2 emissions by sector
(Forced nuclear introduction scenario – Reference case)

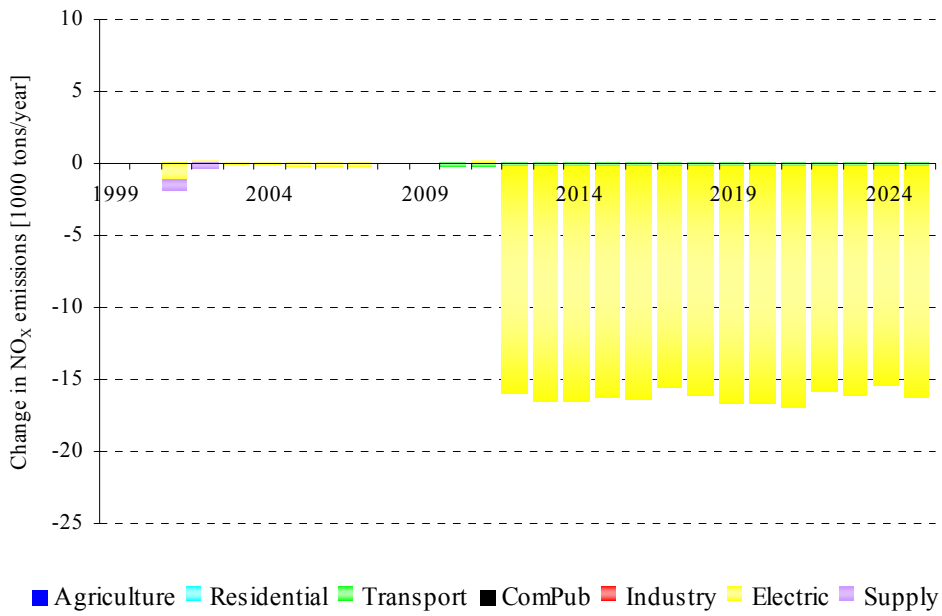

Figure 44. Change in NO_X emissions by sector
(Forced nuclear introduction scenario – Reference case)

Figure 45 shows a summary of the economic comparison of the discussed scenarios. It becomes clear the impact of natural gas prices on the cost at net present value of the alternatives for the expansion of the power sector. The power system becomes very vulnerable to natural gas prices or natural gas shocks and therefore becomes convenient to think and analyze the degree of diversity (fuels and technologies) of the power system and its expansion.

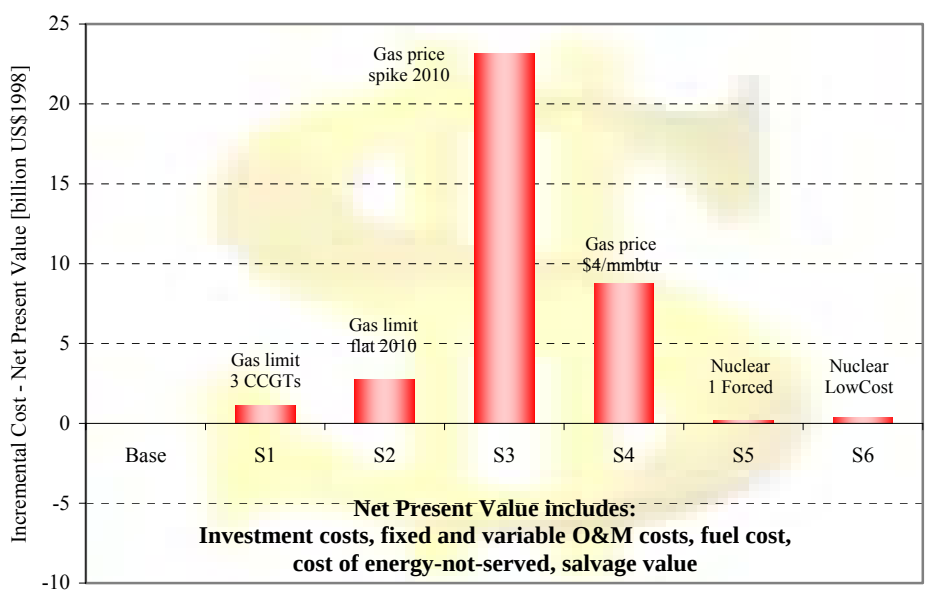

Figure 45. Summary economic comparison of various scenarios

D. Renewables scenario results

The renewables scenario focused on the introduction of additional wind and solar PV for power generation. Other renewables, *e.g.,* mini-hydro and the application of renewables in the end-use sectors should be analyzed in future model runs. The model was configured such that solar and wind technologies compete with grid electricity on a national level, including the isolated system. Cost information was obtained from NREL and DOE-EIA and for the projection of these costs we consider the concept of experience factors. The technology assumptions are given in the following table:

	Wind Farm	**Solar**
Capacity	50 MW	5 MW
Average capacity factor	26.2%	20%
Efficiency	65%	15%
Fixed O&M cost	26.94 $/kW-year	10.2 $/kW-year
Initial capital cost	1,154 $/kW	4,781 $/kW
Experience factor	0.88	0.82

The experience factors for solar and wind essentially represents the cost reduction with each doubling of installed capacity. The resulting cost reductions for solar (from 4,781 to 1,773 $/kW) and wind (from 1,154 to 536 $/kW) over time are shown in Figures 46 and 47.

D1. Effects on power sector

Because of the relative costs of wind and solar (of their technology characteristics), the role of solar PV will be very limited. By 2025, solar will generate only about 1.2 PJ of electricity or 0.1 percent of total generation. This is equivalent to 195 MW of installed PV capacity.

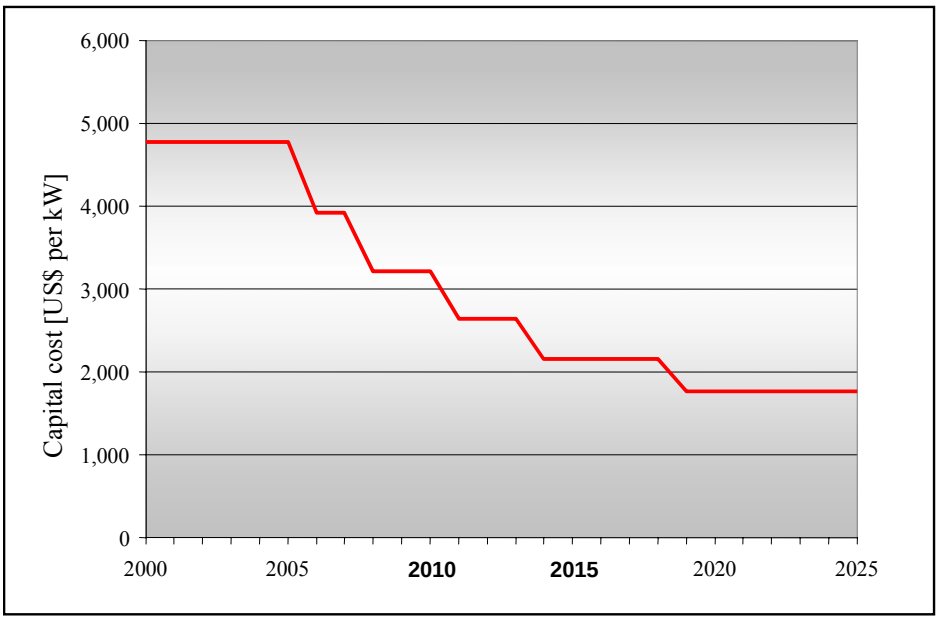

Figure 46. Solar photovoltaic capital cost curve (experience factor = 0.82)

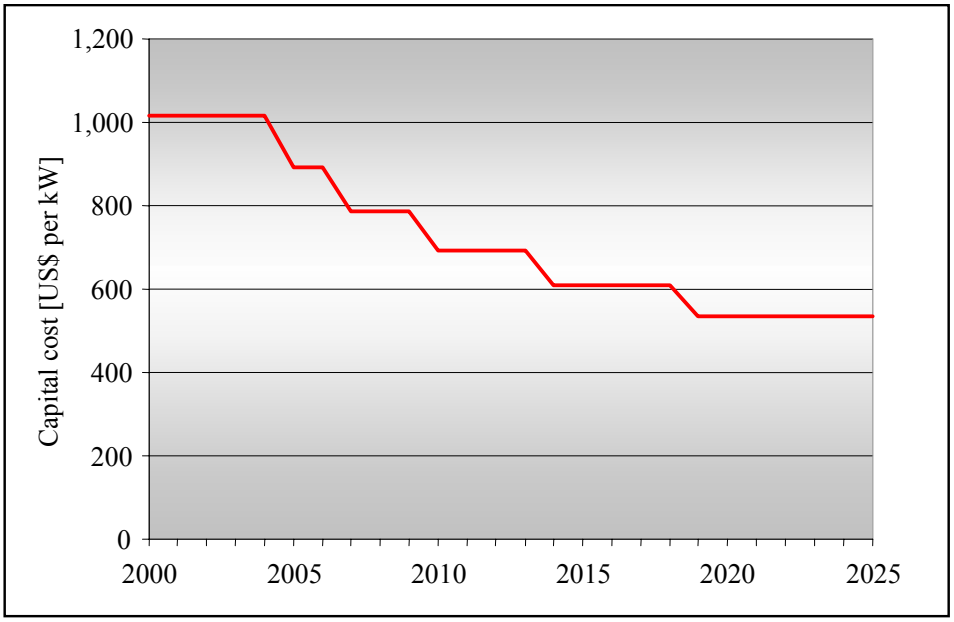

Figure 47. Wind capital cost curve (experience factor = 0.88)

Wind, on the other side, is forecast to penetrate the market relatively rapidly and as given in Figure 48. This energy source is forecasted that will account for approximately 4.9 percent of total generation, that is, 78.3 PJ by 2025. At the assumed average capacity factor of 26.2 percent, about 9,500 MW of wind capacity will be needed to generate this power.

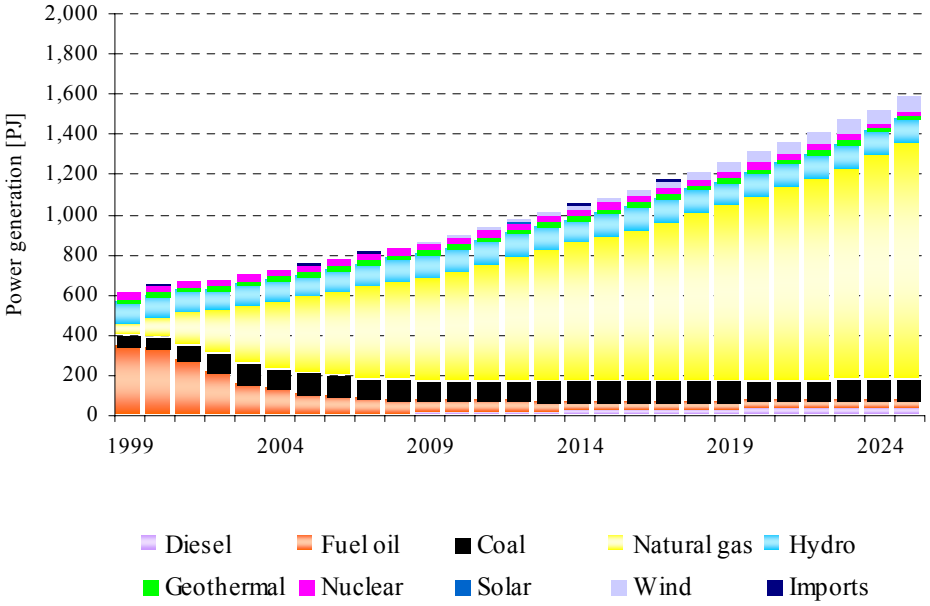

Figure 48. National power generation by fuel type
(Renewables scenario – Reference case)

Figure 49 shows that wind will essentially replace marginal gas-fired generation by up to 93.3 PJ (2025), that is, about 19 percent more than wind electricity. The main reason for this difference is the underlying model implementation which assumes that wind generation will be more dispersed, closer to actual loads, and therefore not subject to the transmission and distribution losses in the electric grid.

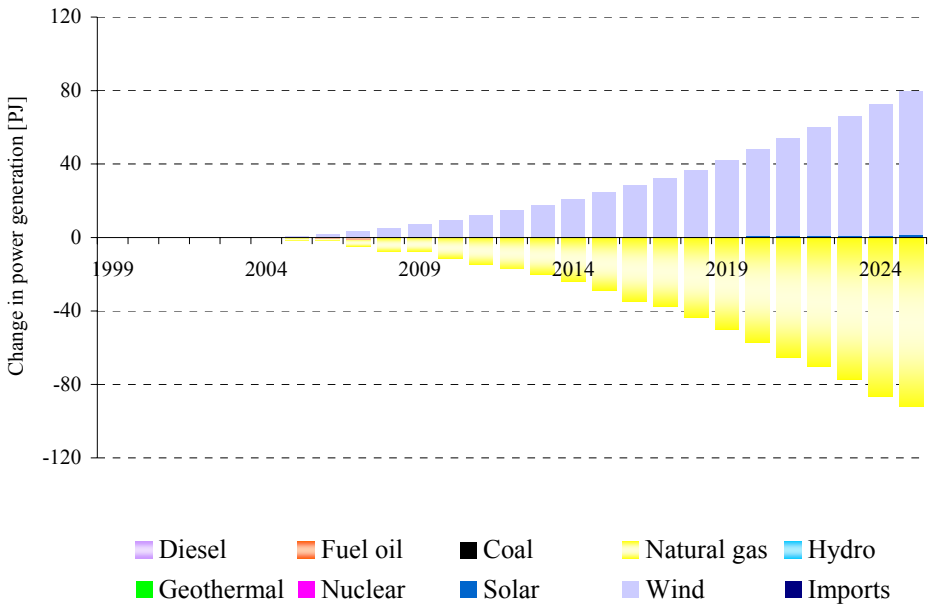

Figure 49. Change in power generation by fuel type
(Renewables scenario – Reference case)

Because of the change in generation mix originated by the incorporation of wind energy, the power sector will require less natural gas. This translates directly into less natural gas imports as shown in Figure 50. The reduction in natural gas imports grows as wind generation increases and reaches approximately 180 PJ by 2025.

At US$707.87 billion in net present value, total economic system cost is higher than under the reference scenario, that is, an incremental cost of US$455.64 million.

D2. Emissions results

The fact that solar and wind replace electricity that is generated mostly by gas-fired combined cycle units has the effect to limit the emission reduction potential of the renewable technologies. NO_X emissions, for example, are 44,000 ton per year (2025) below projected reference case levels (Figure 51). This is equivalent to a 5.5% drop in the power sector emissions and a 1.0% decrease of the total national NO_X emissions. Cumulative NO_X reductions over 2005-2025 total about 351,000 ton.
The combined effect of technologies, solar PV and wind, for example, on CO_2 emissions is shown in Figure 52. As can be seen, the accelerated penetration of renewable power generation results in CO_2 emissions that are up 10 million ton per year (2025) below the reference case levels. This represents a 5.4 percent decrease in power sector CO_2 emissions and a 1.2 percent decrease of total national CO_2 emissions. The total cumulative emissions reductions in the period from 2005 to 2025 are equal 81.96 million ton.

The cost-effectiveness of solar and wind as a GHG mitigation technology is therefore US$5.6/ton CO_2. This value is likely to be lower if we ignore the more expensive solar technologies and include only wind in the model. This should be an area of future investigations.

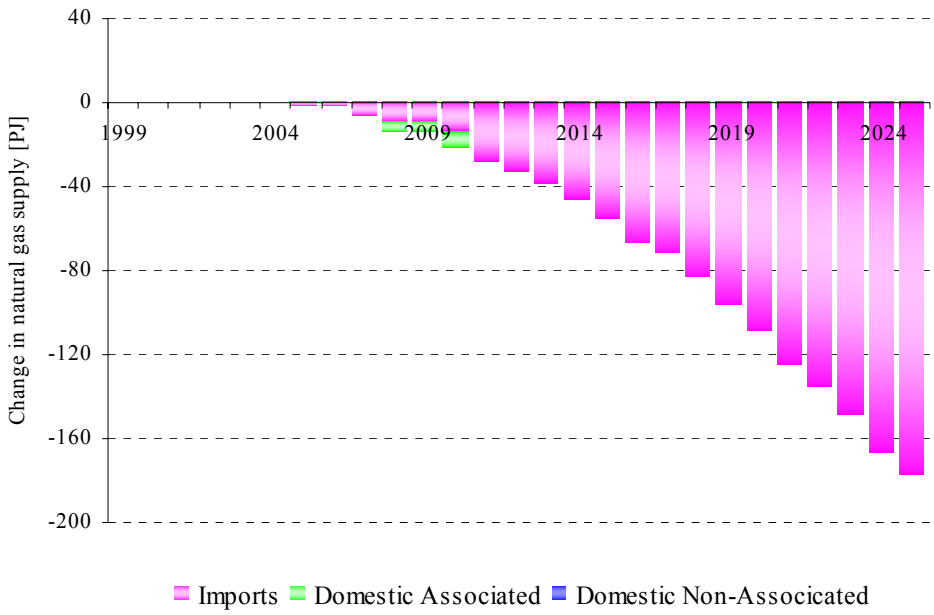

Figure 50. Change in natural gas supply
(Renewables scenario – Reference case)

6. Conclusions and recommendations

For all the analyzed scenarios the general conclusion indicates that Mexico will continue to rely heavily on fossil fuel for its energy trade and final energy consumption. Crude oil production will have to increase from 2.91 million barrels per day in 1999 to 3.78 million barrels per day by 2025.

To keep the proper balance between production and proven reserves of crude oil and gas important investments in oil and gas exploration and production will have to be allocated. In order to reduce the dependency of imported oil products and natural gas the refining and gas processing capacities will have to be increased. Refining capacity will have to be increased from 1.54 million barrels per day in 1999 to 4.07 million barrels per day by 2025. To keep the proper balance between supply and consumption of natural gas with an important participation of domestic production, starting 2010, it will be necessary to incorporate more non-associated gas fields to production. In order to handle the primary gas production and the imports, natural gas infrastructure (production wells, gas pipelines, processing centers and distribution) will have to grow at an accelerated level.

Natural gas will be the primary choice for power system expansion and generation leading to a near-term and long-term need for additional gas imports (or accelerated expansion of natural gas domestic production). Under restricted conditions of financial sources natural gas and environmental policies should be review and fuel oil generation incorporated and analyzed their benefits in the short and medium term.

In the case of the nuclear option specific studies will have to carry out. Special attention has to be paid to the total cost of the expansion scenarios including the internalization of the environmental externalities of the whole energy chain and looking for the total cost at which the nuclear option becomes competitive.

An additional conclusion derived from the study is the need for SENER, CFE and UNAM to analyze with much more detail the issue of economic, environmental, social and political impact of the diversification of the mix of technologies for the long term expansion of the electric system in Mexico as well as for the entire Mexican energy system. This conclusion arises from the vulnerability that exists in case of limitations in the supply of natural gas or in the increase of their prices.

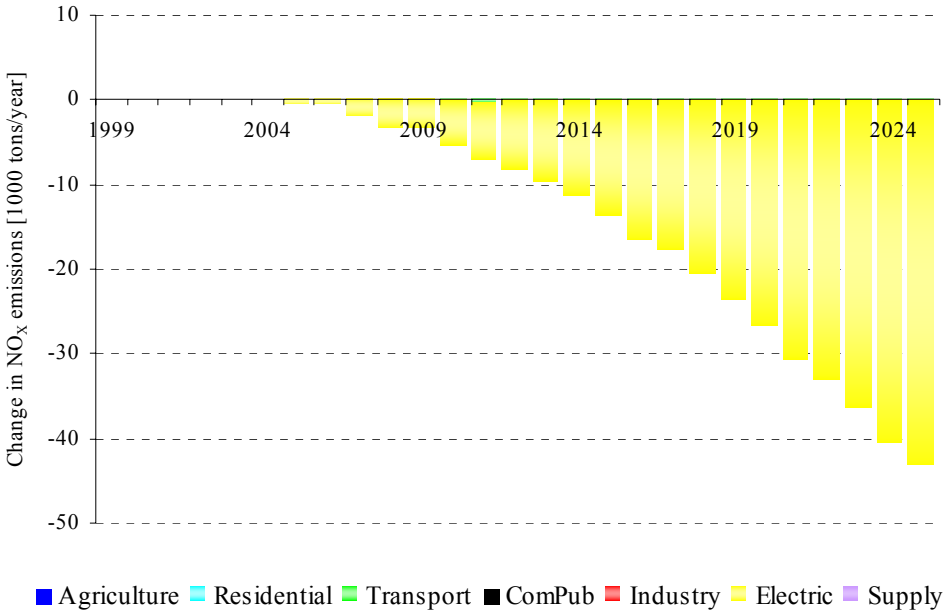

Figure 51 Change in NO_X emissions by sector
(Renewables case minus Reference case)

In the context of diversification it can be recommended that SENER, CFE and UNAM study the possible economic and environmental benefits of incorporating more wind, solar and geothermal units as candidate technologies for the expansion of the electric system and alternative technologies in the other sectors of the Mexican energy system. The results of these studies could indicate the need to incorporate wind and solar technologies in the COPAR document of CFE as well as in the outlook of the electric sector published by SENER (Prospectiva del Sector Eléctrico). On the other hand, at the level of the integrated Mexican energy system the need for the study of the possible economic and environmental costs and benefits of incorporating new technologies for transportation, industrial process and final end uses in the different sector of the energy system.

From the point of view of the model's structure and it use, there is also a need to increase energy data availability and quality in the all the sectors. This is strictly necessary in order to improve the results of the model and the benefits of its use. Significant efforts are to be done in the characterization of the different conversion processes used in the industrial and other sectors. It is urgent to improve availability and reliability of the information related to energy efficiency, costs, final end uses, input/output ratios for different processes and final end uses, etc. This could be achieved by providing information, sources of information, accessibility to the information and a compromise of confidential and correct use of the provided information.

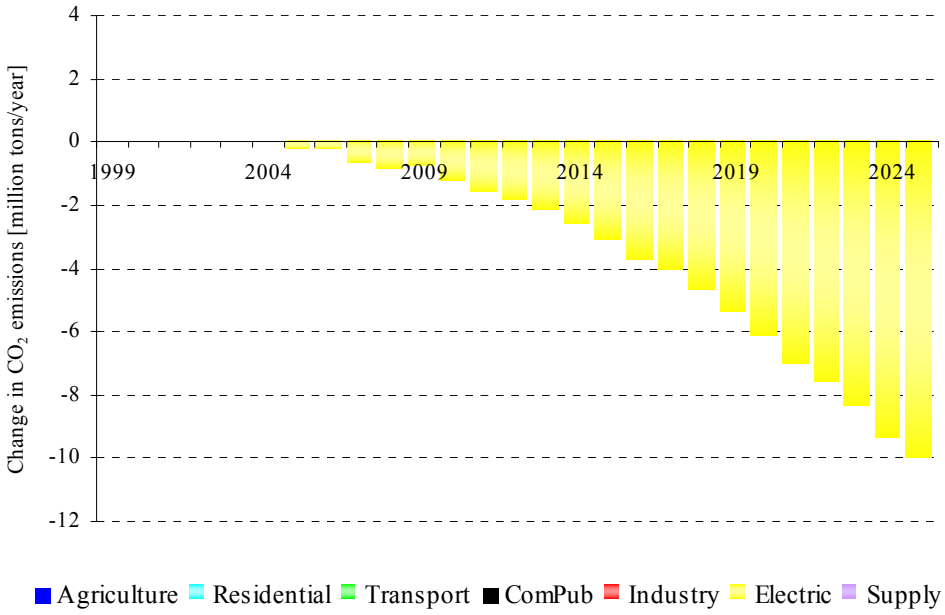

Figure 52. Change in CO_2 emissions by sector
(Renewables scenario – Reference case)

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