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Case studies to assess and compare different energy sources in sustainable energy and electricity supply strategies

Final report of a co-ordinated project 1997–2000

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FOREWORD

The IAEA offers its Member States a comprehensive programme of technical assistance and co-operation, which covers many diverse areas related to peaceful uses of nuclear energy. In the area of comparative assessment, the objective of assistance is to strengthen national capabilities for informed decision making, and for elaborating sustainable choices among alternative options for energy supply and use. In the past, the planning process was designed to meet the future demand for energy at the least engineering cost. However, the pursuit of increasingly sustainable energy options over time has required a broader comparative assessment that addresses economic, social, health and environmental factors.

To support this need, in 1992 the IAEA initiated an inter-agency project on databases and methodologies for comparative assessment of different energy sources for electricity generation (DECADES). Under the project, nine international organizations, European Commission (EC), the Economic and Social Commission for Asia and the Pacific (ESCAP), the International Atomic Energy Agency (IAEA), the International Bank for Reconstruction and Development (IBRD), the International Institute for Applied Systems Analysis (IIASA), the Nuclear Energy Agency of the OECD (OECD/NEA), the Organization of the Petroleum Exporting Countries (OPEC), the United Nations Industrial Development Organization (UNIDO) and the World Meteorological Organization (WMO), agreed to pool their efforts to achieve the common objective of enhancing capabilities for comparative assessment of different energy chains in the process of planning and decision making for the electricity sector. DECADES was initially conceived as a set of generic and national databases detailing the environmental impacts, costs and characteristics of various generating and fuel chain technologies which could be used for comparative assessment by investors and policy makers. These databases were linked to software permitting their easy integration into other energy planning or analysis tools. DECADES was thus organized as a data management system rather than as an overall or long range energy planning tool.

In 1997, the IAEA initiated a co-ordinated research project (CRP) on Case Studies to Assess and Compare Different Sources in Sustainable Energy and Electricity Supply Strategies under the aegis of the DECADES project to conduct a series of national studies using the DECADES package (DECPAC). Under this CRP, experts from more than twenty countries utilized databases and methodologies developed and reviewed under the DECADES project to carry out national comparative assessment studies. At a final Research Co-ordination Meeting (RCM), held from 14 to 16 December 1999, meeting participants agreed on the format of executive summaries to be prepared for each of the national case studies.

This publication summarizes the results obtained and the lessons learned from national case studies carried out under the CRP. The report is intended primarily for managers and senior experts in governmental organizations, research institutes and power utilities who are involved in energy and environmental analysis, interpretation of model results and translation into decision and policy making.

The IAEA wishes to express its gratitude to the chief scientific investigators who were responsible for conducting comparative assessment studies under the CRP and contributing to the preparation of executive summaries contained in this publication. The IAEA also wishes to acknowledge the support of the Government of the United States of America in hosting the second RCM organized under this CRP at the Energy Information Administration of the US Department of Energy, as well as the Government of Switzerland for hosting the third RCM at the Swiss Federal Institute of Technology.

The IAEA officers responsible for this publication were A.I. Jalal and I.F. Vladu.

EDITORIAL NOTE

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Part I
THE DECADES PROJECT

1.1. Background

The IAEA has a long tradition in the analysis and planning of energy systems. In response to requests from its Member States, the IAEA has implemented and disseminated energy system analysis tools that are widely used by national institutions and international organizations. Throughout the 1970s and 80s, the analysis of energy options typically focused on determining the economically optimal manner in which to meet the energy needs of a country. However, heightened interest and awareness in health and the environment has led to a broadening of the analysis that is necessary. In order to assist with comprehensive "comparative assessments" of energy options, the IAEA expanded the scope of its analytical activities to include environmental, health and social impacts together with traditional economic and technical comparisons.

In 1991, a Senior Expert Symposium on Electricity and the Environment was jointly organized by the IAEA and ten other international organizations in Helsinki, Finland. Presentations and discussions at the Helsinki Symposium characterized the general situation in developing countries with respect to energy planning by the following features:

- Rapidly increasing electricity demand with supply system expansion being severely constrained by shortage of investment funds;
- Environmental concerns, particularly of a local and regional nature, gradually receiving increased attention;
- Lack of a systematic effort to compile technical, economic and environmental data pertaining to existing and planned energy facilities and fuels;
- Lack of a proper methodological approach enabling the analysis and incorporation of health and environmental impacts in the planning and decision making process for power system expansion.

The Helsinki Symposium recommended inter alia that programmes of research on comparative assessment of electricity generation options be undertaken and stressed that international organizations having a mandate in this field should co-operate in efforts to provide improved databases and methodologies for comparative assessment.

In response to recommendations of the Helsinki Symposium, an inter-agency project on Databases and Methodologies for Comparative Assessment of different Energy Sources for Electricity Generation (DECADES) was established at the end of 1992. The project aimed at facilitating the development of sustainable strategies which provide energy services required for supporting economic growth and improving the quality of life while minimizing the adverse health and environmental impacts from the supply and use of energy. Three main tasks were specified in the work programme adopted for the DECADES project, including:

- Establishment of databases and information systems to support comparative assessment;

- Development of an integrated software package for comparative assessment of electricity generation options;
- Training and support for Member States in implementing comparative assessment case studies.

DECADES ultimately was designed mainly to support two types analysis: comparative assessment of specific sites and projects, and assessment of the full energy chains associated with these specific choices. Full energy chain analysis is a form of life cycle analysis that allows decision makers to estimate and compare the full technological, economic and environmental implications and requirements of investment in a particular facility, technology or fuel choice. Both capabilities require, among other things, extensive technology and environmental databases.

Phase 1

Development of the DECADES tools started in 1993. These consist of databases and analytical software that can be used to evaluate trade-offs between technical, economic and environmental aspects of different electricity generation technologies, chains and systems. Two types of technology databases were developed to provide comprehensive, credible and up-to-date information on energy chains for electricity generation. The Reference Technology Database (RTDB) contains technical, economic and environmental data on typical facilities covering energy chains that use fossil fuels, nuclear power, and renewable energy sources for electricity generation. Country Specific Databases (CSDBs) store data that are specific to a country or region for the purpose of carrying out case studies with the DECADES analytical software.

This first phase of the DECADES project, establishing the relevant tools and data into a package for training and distribution (DECPACS), was reported at a Symposium on Electricity, Health and the Environment: Comparative Assessment in Support of Decision Making, held 16 to 19 October 1995, at the IAEA in Vienna. The Symposium was organized jointly by international organizations participating in the DECADES project in order to enhance and strengthen information sharing and co-operation between interested and affected parties in the fields of electricity demand analysis and supply planning, aiming at implementing sustainable policies in the power sector.

Phase 2

The second phase of the DECADES project consisted of a CRP on Case Studies to Assess and Compare Different Energy Sources in Sustainable Energy And Electricity Supply Strategies. The purpose of this CRP, which ran from 1997 to 2000, was to enhance the capabilities of Member States, particularly developing countries, to identify optimized energy mixes for electricity generation that meet environmental protection standards and regulations prevailing in different countries at least cost. The main objectives were to:

- Develop country specific databases containing a comprehensive and harmonized set of technical, economic and environmental data for energy chains that use fossil fuels, nuclear power, and renewable energy sources for electricity generation;
- Design and carry out national case studies on comparative assessment of different options and strategies for electricity generation in conformity with the objectives of sustainable development;

- Demonstrate the application of databases and methodologies established within the DECADES project;
- Prepare, publish and disseminate a report on the case studies carried out, highlighting the main conclusions and findings, both technical (about the applicability of DECADES) and substantive (about the role of different electricity generation options in sustainable electricity supply strategies).

Extensive training and long-term capacity building was carried out in some 45 countries throughout the course of the DECADES project. In these countries, experts in the fields of electricity system analysis, economics and environmental impact assessment assembled fourteen CSDBs and conducted more than twenty national case studies to identify electricity generation strategies for reducing atmospheric emissions in a cost-effective manner.

Research conducted under the CRP constituted in one sense a field test of DECADES. As shown in Table 1.1, and in the case studies that follow, a variety of DECADES tools was used to address a broad range of issues.

1.2. Characteristics of the DECADES tool kit

1.2.1. DECADES databases

Under the DECADES project, two types of databases were developed to provide comprehensive, credible and up-to-date information on energy chains for electricity generation.

The Reference Technology Database (RTDB) contains generic data on technical, cost, and emissions parameters of energy chains that use fossil fuels, nuclear power, and renewable energy sources for electricity generation. RTDB provides both quantitative and qualitative data for all levels of an energy chain, i.e. from resource extraction to waste disposal. At present, the database contains data for about 300 technologies. This comprehensive database, which pre-dated to a large extent the use of web-based databases and the widespread publication and adaptation of External results, can serve as a default reference where national data are non-existent.

Country Specific Databases (CSDBs) store data on electricity generation technologies for a specific country or region. CSDBs follow the structure and format of the RTDB, but are intended to be used for country or regional case studies. CSDBs are accessed by the DECADES analytical software to perform assessments at the energy facility, energy chain and electricity generation system levels.

1.2.2. DECADES analytical software

The DECADES analytical software (DECPAC) is designed to access information stored in the DECADES databases for analysis and comparison of costs and environmental burdens at the power plant, energy chain and electric system levels.DECPAC is based on IAEA tools such as WASP and ENPEP, adapted specifically to the management and analysis of the DECADES data. Sophisticated graphic display capabilities facilitate data display and results reporting.

Table 1.1. Country case studies and the issues analysed

Issues Addressed	Case Studies																									
	Argentina	Brazil	Bulgaria	Belarus	China	Croatia	Cuba	Egypt	Greece	Hungary	Indonesia	Israel	Macedonia	Moldova	Pakistan	Peru	Philippines	Poland	Romania	Russia	Slovakia	Slovenia	Swiss	Thailand	Turkey	Uzbekistan	USA
Updating CSDBs	X	X			X		X	X					X			X		X		X							
Electricity Generation Facilities	X						X	X	X		X	X	X	X		X	X	X	X			X				X	
Front end and back end facilities	X		X		X	X	X	X	X				X		X		X	X	X	X	X	X			X	X	X
Energy chains (extended)	X			X	X		X	X				X	X						X		X	X			X		X
Site specific information	X	X	X			X	X	X				X		X						X					X		
Enhancements of comparative assessment methodology							X													X							
Assessment of health and environmental impacts of energy chains		X	X		X	X	X	X			X	X				X	X		X	X							
Evaluation of externalities		X		X	X														X								
Least cost optimization with emission restrictions		X		X	X	X	X				X	X	X		X				X	X					X		
Multiple fuel chains (extended representation)				X				X												X	X						
Demand forecast	X				X	X	X	X				X	X	X				X	X	X		X				X	
Energy resources	X						X	X				X	X	X				X		X		X					
Modeling of co-generation (energy conservation-efficiency)				X							X	X	X					X	X	X	X	X					
Inter-connection of regional and national grids														X	X					X							
Assessment of actual costs of fuels	X			X										X					X	X		X					
Integrated Impact Assessment		X	X																			X					
Impact of DSM on fuel mix (energy efficiency)				X								X					X	X	X		X	X					
Cost effectiveness of reducing atmospheric emissions					X															X							
Retrofit of existing fossil fuels power plants		X		X			X					X						X	X						X		X
Optimum use of abatement devices to meet emission targets		X		X				X			X	X	X					X	X						X		X
Cost effectiveness of nuclear option in reducing CO2 emissions		X		X			X				X		X			X		X	X	X							
GHGs mitigation options		X			X			X												X							
Fuel switching	X							X											X						X		
Carbon tax									X											X		X					X
Nuclear power	X			X									X			X			X	X							
Sustainable energy mixes																											
Energy efficiency (conservation, DSM)				X	X			X				X		X		X	X	X	X		X	X					
Availability of energy resources	X						X	X						X					X	X					X		
Potential role of renewable								X	X		X	X	X	X						X		X				X	
Potential role of nuclear	X			X			X				X		X	X		X	X	X	X	X							
Sustainable indicators/analysis			X	X			X				X	X					X	X	X			X					
Decision aiding methodologies		X																		X		X					
Multi-criteria decision analysis (several models)		X	X				X												X	X		X	X				
Trade-off analysis		X		X																			X				

The DECADES tools support three levels of analysis:

1. ***Plant-level analysis*** is used for preliminary screening of different electricity generation options. Emission factors for main air pollutants are estimated based on fuel characteristics and power plant performances. A modular representation of pollution abatement technologies allows for user specification of appropriate abatement technologies for a given power plant. Power plant characteristics are adjusted to account for abatement technology effects on capital cost, fixed and variable operating and maintenance costs, plant capacity, plant efficiency, reagent consumption, and waste generation. Simple cases can be defined to compare power plants in terms of annual electricity generation costs, air pollutant emissions, solid waste generated and land use.

2. ***Chain-level analysis*** provides general data and analysis sufficient to present a broad view of the major tradeoffs between technical, economic, health and environmental aspects of energy chains. It supports comparative assessment of full energy chains for electricity generation, from resource extraction to waste disposal. Chain level results include: mass flow of fuels and waste, levelized cost of electricity generation and quantities of environmental burdens such as air pollution and total greenhouse gas emissions (CO_2 equivalent), water effluents, solid waste generation and land use. Environmental burdens from auxiliary materials such as electricity, fuels and materials for construction and dismantling can also be also calculated. Direct comparisons of different energy chains are possible using a side-by-side display, combined with simple access to emissions, residuals and economic data. Scenarios, in which a fixed demand is met by a given mixture of energy chains, can be established and evaluated in terms of annual air emissions, solid waste generation and land use.

3. ***System-level analysis*** allows users to quickly screen electric generation system expansion strategies and to conduct comprehensive studies to develop mixes of energy chains, which meet electricity demand for a country or region. The system level-planning tool contains three electric system analysis options, ranging from preliminary analysis with screening curves to sophisticate least-cost optimization with dynamic programming. It was derived from the IAEA's WASP model with an enhanced graphical interface, improved computation of environmental residuals (e.g. air pollutant emissions, land use and waste generation) and extensive reporting capabilities. The environmental residuals are estimated taking into account the full energy chains composing the system. The cost effectiveness of different air pollutant abatement strategies is also estimated.

4. ***A decision aiding module (DAM)*** that solves multi-criteria decision analysis problems is included in DECPAC. This permits comparison of the complex of alternatives and the wealth of information on costs and environmental burdens generated by DECADES. It is applicable at the level of power plants, full energy chains, or in the context of alternative expansion plans for generating system as a whole.

1.3. The co-ordinated research project – Case studies

1.3.1. Background

Over the course of the DECADES project, the main focus was on development of databases and methodologies (1993-1996), training and dissemination of tools for comparative assessment (1997-1998) and use of these tools for carrying out comparative assessment studies (1999-2000). By the end of 2000, over 45 Member States had received a copy of the DECADES version 1.0 software together with the user's manual, and the requisite training in use of the package. Feedback provided by these users proved helpful in testing the DECADES Tools (RTDB, CSDBs and DECPAC) and preparing for the release of version 1.0 of the software.

Many of these Member States then participated in the extended CRP on Case Studies to Assess and Compare Different Energy Sources in Sustainable Energy and Electricity Supply Strategies. Their participation varied from year to year, but over-all, some 30 countries did conduct national studies using the DECADES tools, addressing a wide range of issues, including: determining cost-effective strategies for reducing local atmospheric emissions, assessing greenhouse gas mitigation options, incorporating environmental regulations into long-term electricity system expansion planning, and employing multi-criteria decision analysis to identify energy options that are consistent with national objectives and possibilities.

Given the multi-disciplinary aspects of the DECADES package, an important aspect of structuring the project and the CRP, was to involve experts from different countries and with different scientific backgrounds. The exchange of experience and information among disparate teams confronted with similar challenges, such as data collection, technology description, fuel chain definition and comparison, and electricity generation system analysis, resulted in the identification and implementation of common approaches for solving problems.

1.3.2. Results of the CRP

The DECADES project, culminating in this CRP, firmly established the principle, the policy and the feasibility of comparative assessment as a necessary aspect of informed decision-making. This is perhaps its most important contribution. While DECADES is not the only or necessarily the most universal tool for such assessments, it has definitively demonstrated the need, the benefits and the practicality thereof. The CRP case studies highlight the both the efficacity and the limitations of DECADES as a tool for comparative assessment, as discussed below.

1.3.3. Country specific databases

Under the CRP, thirteen new CSDBs were created following the concept of full energy chains. These databases contain inventories of energy-related technologies and fuels, and associated auxiliary materials. The CSDBs also contain specific information on the respective country's existing power system, candidate technologies for future expansion, load profile and forecasted electricity demand. Although progress was made in filling gaps in information needed for carrying out comprehensive comparative assessment studies, in many cases data are still missing for mining, transportation, fuel preparation and waste disposal facilities. This highlights one major shortcoming of the DECADES assessment package, namely that proper maintenance and updating of the RTDB and the CSDBs entails consumption of significant resources. In this respect, the value of these databases has largely been superseded by the use of web-based databases not available at the time that DECADES was conceived.

1.3.4. Comparative assessment of energy options

Results from the major country case studies are summarized in the following chapters. These case studies cover an analytical period ranging from 1996-2000, and may include entries superseded by subsequent developments. This in no way diminishes the value of these summaries in highlighting the relevance of comparative assessment for decision makers, as they illustrate in a number of ways the differentiated impacts of specific policies on alternative energy technologies. The CRP case study summaries demonstrate particularly the different implications that enforcement of environmental regulations would have for alternative power system expansion options in terms of investment requirements, operating costs, environmental burdens and external costs of electricity generation. These comparative analyses show that the magnitude of these impacts is very much dependent on the strategies adopted to comply with the regulations. Some national case studies found nuclear power to be part of an optimal strategy for future expansion of the electricity sector in a sustainable manner.

Part II
COUNTRY CASE STUDIES

1. ARGENTINA

ANALYSIS OF NUCLEAR POWER COMPETITIVENESS IN ARGENTINA AND ITS INCIDENCE ON GHG EMISSIONS USING DECADES PROGRAMMES

1.1. Summary

In Argentina, power demand is expected to grow significantly over the next 20 years. Based on current projections of demand growth, up to 32 000 MW of new electricity generation capacity will need to be constructed before the year 2020.

Within the present [2000] economic and regulatory context — low natural gas prices and a lack of restrictions on greenhouse effect gas (GHG) emissions — a great part of these 32 000 MW will be covered by equipment burning natural gas. However, this situation will provoke an important growth of GHG emissions generated by the power sector of the country. In fact, during the period 1995–2020, these emissions would be quintupled.

Although at present power sector emissions in Argentina represent a low percentage of the total emissions for the country and the total emissions in the country represent a low GHG per inhabitant (3.7 Ton/in h. –year), as compared with industrialized countries, this situation could be reversed if appropriate decisions are not taken.

Considering that, for today, nuclear power is the only economically feasible and environmentally benign alternative for GHG mitigation in the area of base load electricity generation, the purpose of this research contract is to analyse variables that affect nuclear power's competitiveness in Argentina's electricity market. Specifically, the study analysed how nuclear power could compete with other generation options under alternative assumptions regarding energy prices, taxation on carbon-equivalent emissions, and interest rate and capital cost for new nuclear power plants. The various scenarios were compared based on the resulting technology mix and CO_2 emissions.

1.2. Price of Fossil Fuels

For the base scenario, the price of natural gas was assumed to be \$65/1000 m^3 (\$1.95 /MBTU) in the region of Greater Buenos Aires. This was the purchase price of natural gas for one of the largest generators in the region, but is 23% lower than the regulated reference price (\$83.95/1000 m^3) set for the same region by the National Gas Regulator Authority (ENERGAS).

The price of natural gas in Argentina does not have a direct relationship with the international price of oil, because of the large domestic reserves of this resource and the important infrastructure (including pipelines) required for its export. Nevertheless, this study estimated that in the long term the domestic price of natural gas in Argentina would follow, although with great delay, an increase in the price of oil.

Analyses conducted with the DECADES analytical software, DECPAC, indicated that if the price of natural gas rose to \$143/1000 m^3 (\$4.30 /MBTU), nuclear power would be the economically optimal generation technology for meeting future growth in electricity demand and would also produce an important reduction in GHG emissions.

1.3. Carbon Tax

Under the same premise as defined in the base scenario, DECPAC was used to determine the level of tax on CO_2 emissions that would produce a decrease of approximately 50% in growth of GHG emissions from the power sector. It was determined that under existing conditions in Argentina, the value of en emissions tax that would produce this change is \$39.30/ ton CO_2.

1.4. Nuclear Investment Cost and the Clean Development Mechanism

The Clean Development Mechanism (CDM) is one of the "flexible mechanisms" for GHG emission reductions adopted under the Kyoto Protocol, and is the only co-operative mechanism in the frame of the protocol that involves non-Annex-I countries. The CDM aims at helping these countries contribute to global GHG emission reductions while promoting their own sustainable development.

Under this mechanism, an Annex-I Party would invest in a clean technology project in a non-Annex-I country, which it might not be able to afford on its own, but which produces fewer GHG emissions than the affordable technology that would have been used instead. In the case of Argentina, nuclear plants would qualify as candidate technologies given their higher capital costs and their negligible emissions.[1]

For the current study, the DECADES tools were used to identify the level of investment in nuclear power, under the CDM, that would result in a 50% decrease in the CO_2 emission growth with respect to the base scenario. It was found that in order achieve such a reduction in GHG emissions; the assumed investment cost of a nuclear power plant would need to be reduced by 65%.

Since nuclear power generation is capital intensive, the interest rate of the investment has a strong effect on amortization and therefore on levelized generation cost. The interest rate at which nuclear power generation becomes competitive was analysed.

In Argentina, interest rates for investments are much higher than in industrialized countries. Although the rates used in this section of the study may seem utopian for a Latin American country, they are considered here in a context of promoting non- GHG-emitting sources.

Furthermore, we considered in this CDM analysis an additional scenario where a very low GHG emission tax is applied, \$10 / ton of CO_2. For combined cycle plants, this tax implies that a natural gas cost of \$4/MW·h.

1.5. Results

The mixed scenario analyzed is the simultaneous use of GHG emission taxes and investment promotion (through the CDM) of sources that do not emit GHG. It was assumed that funds obtained through taxes on GHG emissions would be applied to reducing the investment cost of nuclear generation.

[1] Editor's note: Although at CoP 6 bis, nuclear power was disqualified for use in clean development mechanisms for Annex 1 countries for the first compliance period, it would still be applicable for CDM projects between non-Annex 1 countries, a potential advantage for developing countries that are developing their own reactors for export

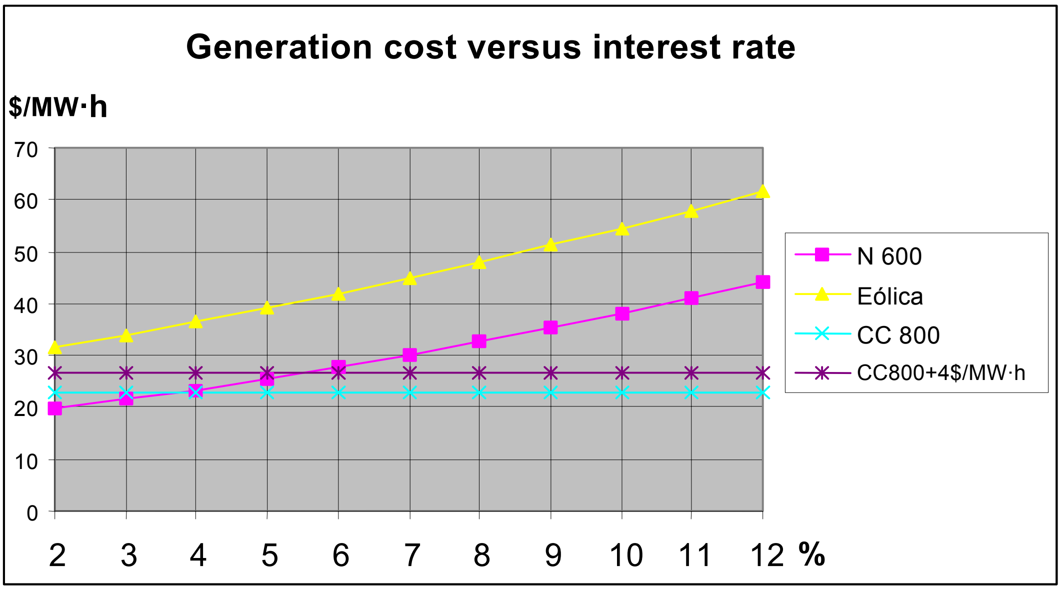


Figure 1.1. Interest rates that turn nuclear generation competitive to produce an effective reduction of GHG emissions.

The objective in this case is to find the lowest tax that, applied to the GHG emissions, will generate sufficient funds to subsidise the investment in non-GHG-emitting sources, producing an effective reduction on GHG emissions with respect to the base scenario.

In this mixed scenario, it was found through use of the DECADES tools, that with a carbon tax of \$20/ ton CO_2, \$10 billion could be collected during the relevant period, sufficient to reduce by 31% the investment required to build 18 nuclear power plants of 600·MW each. This produces the desired effect on reduction of GHG emissions, at an increased energy cost in the wholesale electricity market of about \$7·/ MW·h.

2. BELARUS

ANALYSIS OF ELECTRICITY CHAIN FACILITIES AND LEAST COST EXPANSION PLAN FOR BELARUS ELECTRICITY GENERATION SYSTEM

2.1. Summary

Under the IAEA's co-ordinated research project on Case Studies to Assess and Compare Different Energy Sources in Sustainable Energy and Electricity Supply Strategies, the DECADES Computer Tools and BALANCE model were used to develop a least cost expansion plan for the electricity generation system in Belarus and quantify the resulting environmental burdens.

In the past, several studies were conducted to forecast electricity consumption and peak load demand in Belarus; in particular forecasts were developed by the World Bank, London Economics Ltd., and the Belarus Thermal and Power Institute (BTPI). Peak load forecasts from past studies are presented in Table 2.1, along with the assumed values for the current study.

Table 2.1. Peak Load Demand Forecast, MW

Year	World Bank		London Economics		BTPI	This study
	Max.	Min.	Max.	Min.		
2000	6960.0	6260.0	6110.0	5551.0	6430.6	6645.5
2005	8463.0	7785.0	7167.0	5810.0	8242.0	7529.2
2010	10394.0	9696.0	8298.0	6605.0	9475.3	8530.8
2015	11759.9	10970.1	9360.5	7450.7	10720.4	9666.0
2020	13305.2	12411.7	10559.1	8404.8	12129.2	10952.7

The DECPAC analysis considered three scenarios of electricity system expansion, which differ only by the amount of heat expected to be generated by co-generation units. The list of candidates for each scenario includes:

PT35 – Co-generation unit
CCLE – Combine cycle unit
K300 – Steam turbine unit
NUCL – Nuclear unit

Technical parameters for these expansion candidates are summarized in the Table 2.2.

Taking into account the high level of uncertainty associated with the construction cost of nuclear power in Belarus, this study used an average value based on the cost of constructing nuclear power plants in different countries. This average cost reflects the total investment cost including costs associated with decommissioning and interest during construction. Economical parameters for the expansion candidates are summarized in the Table 2.3.

Table 2.2. Technical parameters of the candidates

Plant name	Capacity Single unit MW	Fuel type	Heatrate kcal/kW·h Base	Heatrate kcal/kW·h INCR	FOR %	Days schl Days	O&M Fix, $/kWm	O&M Var, $/MW·h
PT35	45	Wood	2441	2254	7.2	58	1.15	8.27
CCLE	450	Gas	2145.74	1560.79	8.8	71	0.494	3.56
K300	450	Gas	2450.61	1653.12	8.3	69	0.567	4.08
NUCL	500	Nuclear	2570	2570	11	50	5.0	1.0

Table 2.3. Economic parameters for expansion candidates

Plant name	Capital cost Inclusive IDC (Depreciable) part $/kW	IDC %	Construction time Years	Plant Life Years
PT35	968.8	10.02	2.5	25
CCLE	680.7	11.92	3	25
K300	847.6	13.79	3.5	25
NUCL	1880	29.22	8	30

Since about 60% of the installed capacity in the Belarus electricity generation system is from co-generation units that also provide heat for industrial and residential needs, it is important for system level analysis to accurately represent the combined heat and power system in the country. To overcome difficulties with representing co-generation units in the DECADES Computer Tools, this study also used the BALANCE module of ENPEP to capture the effects of the combined heat and power system.

Results of the least-cost power system expansion plan developed with DECPAC were transferred to the BALANCE module to determine the share of total heat demand that would be met by co-generation units and conventional boilers. Representative heat rates were specified for co-generation units to reflect the amount of steam to be extracted from the turbine for heat supply. The model runs then determined the potential for selling heat generated by co-generation units on the energy market of Belarus.

Based on the results of BALANCE runs, the additional income from heat sales was included in the calculation of present value and internal rate of return for the expansion candidates. Integrated results of the combined DECPAC-BALANCE case studies are summarized in the Table 2.4.

Further analysis was conducted to consider a greater number of expansion candidates in developing the optimal solution and to compute the resulting environmental burdens. The extended list of candidates for electricity generation system expansion includes the following units:

CC90 – Combine cycle units for electricity generation. Technical and economical parameters conform to units to be produced by Company ALSTOM.

GTR1 – Gas turbine is a typical unit that is produced in Ukraine and Russian Federation.

PT60 – Co-generation steam turbine with steam extraction for industrial needs and heating.

Table 2.4. Integrated results of the DECPAC and BALANCE runs

Parameter	Unit	CCLE	NUCL	K300	PT35		
					Case 1	Case 2	Case 3
Electricity price	\$/kW·h	0.055	0.055	0.055	0.055	0.055	0.055
Heat price	\$/Gcal				25	25	30
Discount rate	Fraction	0.05	0.05	0.05	0.05	0.05	0.05
Levelized O&M cost	K\$	111 955	302 345	98 449	42 562	42 107	30 592
Levelized capital cost	K\$	234 519	985 272	242 146	134 240	134 240	134 240
Levelized fuel cost	K\$	706 409	267 760	281 225	184 871	293 132	146 580
NPV	K\$	370 847	1122 300	58 315	65 638	43 722	12 883
IRR	%	21.14%	11%	7.02%	9.80%	8.37%	5.90%

K300 – Steam turbine for electricity generation only.
T115 – Co-generation unit with steam extraction for buildings heating.
NUC1 – Nuclear power unit NGWWR-640.
NUC2 – Nuclear power unit NPP-92.

Comparative analysis of different scenarios of electricity generation system expansion shows that the optimal expansion solution contains a mix of technologies as displayed in Figure 2.1, with nuclear power accounting for about 24% of total installed capacity by the end of the study period.

The expected emission of hazardous substances from the power system is presented in Table 2.5. These data have been used for calculating payment for environmental damage from emissions of SO_x, NO_x, CO, CH_4 and NMVOC. The cost of this environmental damage, calculated in accordance with the accepted methodology in Belarus, accounts for approximately 0.015–0.02% of total generation cost.

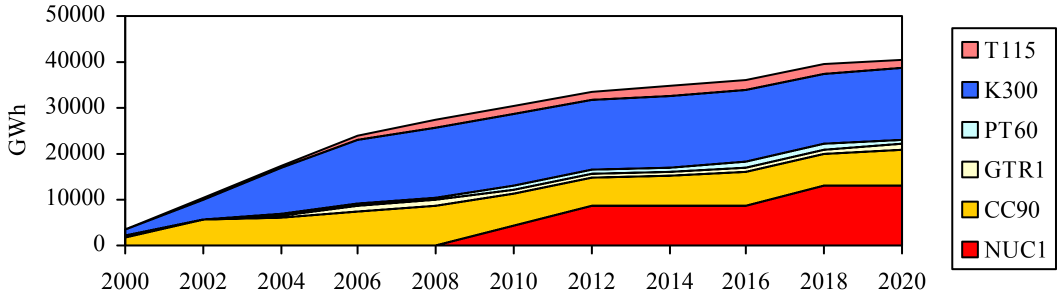


Figure 2.1. Expected electricity generation by technology type.

Table 2.5. Expected emission of hazardous substances (Thousand tons)

Year	CO_2	SO_x	NO_x	CO	CH_4	NMVOC
2000	20175.76	8.97	38.94	7.27	1.38	0.18
2004	22001.87	7.99	42.85	7.99	1.51	0.16
2008	23457.05	4.88	46.47	8.67	1.64	0.10
2012	20742.92	5.01	40.94	7.64	1.44	0.10
2016	22191.61	5.14	43.85	8.18	1.55	0.10
2020	20790.31	3.39	41.38	7.72	1.46	0.07

2.2. Conclusions and Recommendations

For Belarus economic and political independence require energy supply independence. As a main result of these studies, the main trends for sustainable development of the electricity generation system are the following:

- Incorporate the IAEA's methodologies and tools for comparative assessment into the decision making process for the electricity system expansion in Belarus;
- Use domestic energy resources for electricity and heat generation;
- Rehabilitate existing electricity generation capacities and meet needs for new installed capacity by combine cycle units and nuclear power plants;
- Implement energy saving technologies on a wide scale.

The results of this study contributed to development and updating of the document on "Main Issues of Energy Policy of Republic of Belarus for Period 2001–2005 and up to 2015" that was approved by the Government of Belarus in October 2000.

It is considered highly improbable that any single variable analysed under this study will have a near-term impact of sufficient magnitude to substantially modify the economic competitiveness of nuclear power or produce the desired reduction in GHG emission projections.

In turn, we consider the mixed scenario to be highly possible. For instance, an increase of fossil fuel prices would not by itself produce an important change in either nuclear generation competitiveness or GHG emissions. But such a price increase could produce a substantial change in the short or medium term (10 years) if coupled with emission restrictions or taxes and with lower interest rates on investment in generation sources that do not produce GHGs.

3. BULGARIA

COMPARATIVE ANALYSIS OF SCENARIOS FOR SUSTAINABLE DEVELOPMENT OF THE ELECTRICITY SECTOR IN BULGARIA

Since the political transformations in 1989, Bulgaria is still in transition to a market economy. This period has seen great instability in all economic sectors. As a result, a Currency Board was established in Bulgaria to stabilize the economy and carry out a program of privatization. This process requires restructuring of all sectors of the economy. For this reason, in 1998, the Bulgarian Parliament accepted a national strategy for development of the energy sector till 2010. The minimum and maximum versions considered in the energy strategy are based on the macro economic prognoses for the country's development. An essential part of the strategy is devoted to the power sector development, which began the process of restructuring in 2000. The restructuring of the power sector is based on the sustainable development of this sector.

The aim of the present investigation is to develop and analyse, from a sustainable development point of view, different scenarios for Bulgarian electricity sector expansion till 2020. For these purposes the DECADES tools, especially the model DECPAC, were applied to the data stored in the Bulgarian country specific database to analyse the costs and environmental damages associated with alternative scenarios for closure of four units at the Kozloduy nuclear power plant. The year 1998 is considered as a base year for the study.

The following four scenarios for development of the Bulgarian electricity sector are implemented for the period 1998-2020:

Scenarios 1 – under high growth forecast of electricity demand, shut down nuclear units 1 and 2 in 2003, 3 in 2010 and 4 in 2012.

Scenarios 2 – under high growth forecast of electricity demand, shut down of nuclear units 1 and 2 in 2003 and 3 and 4 in 2007.

Scenarios 3 – under low growth forecast of electricity demand, shut down of nuclear units 1 and 2 in 2003 and 3 and 4 in 2007.

Scenarios 4 – under low growth forecast of electricity demand, shut down of nuclear units 1 and 2 in 2003, 3 in 2010 and 4 in 2012.

After using DECPAC to define the economically optimal expansion plan for each of the four scenarios considered, the RAINS model was applied to calculate SO_2 and NO_x emissions and depositions associated with this expansion plan, and to assess their impact on critical ecosystems. The resulting economic costs from DECPAC and environmental damages from RAINS were then compared using the Decision Aiding Module.

The choice of projects for a least cost expansion plan is based on different analyses and comparative assessments at the power plant and energy chain levels. The most probable candidates for future power expansion are as follows:

Lignite coal - 4 units of 300 MW each;

Imported bituminous coal - 2 units of 300 MW each;

Natural gas - 2 units of 150 MW each and 1 unit of 450 MW combined cycle;

Nuclear units - 1 unit of 1000 and 1 of 600 MW each (in scenarios 1 and 2) and 2 units of 600 MW each (in scenarios 3 and 4);

Hydro projects - 2 projects of about 300 MW total.

The four scenarios were analyzed in accordance with the annual peak loads presented in Table 3.1 for the respective scenarios and selected years. The major technical and economic results are summarized in Tables 3.2 and 3.3.

Table 3.1. Annual peak load [MW]

Year	2000	2005	2010	2015	2020
Scenario 1 and 2	8,020	8,640	9,430	10,250	11,060
Scenario 3 and 4	7,280	8,000	8,800	9,500	9,970

Table 3.2. Total generating capacity [MW] and total electricity generated [GW·h]

Technical results \ Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario4
Generating capacity	231,200	230,016	225,915	227,176
Electricity generated	1,127,449	1,127,355	1,053,778	1,053,946

Table 3.3. Total expected cost of operation and capital cash flow, million $

Economic results \ Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario4
Expected cost of operation	34801.1	35085.1	32693.7	32650.8
Capital cash flow	4922.4	4980.0	4099.0	3924.3

The atmospheric emissions of SO_2, NOx, CO_2 and particulates were computed for three emission scenarios: no control (wc); SO_2 and particulate abatement control (WFGD and EPS) applied only to the new thermal power plants (TPP) (nc); and all TPP controlled (ac). In the latter case not only new plants but also existing ones are expected to be equipped with air pollution control equipment.

The Decision Aiding Module (DAM) was applied to the results obtained in order to choose the best scenario. For that purpose 12 alternatives in 3 blocks are considered - for each scenario and for the above described cases wc, nc and ac. Twelve rating criteria were also selected, separated in 3 blocks. They include cost (investment + production + abatement), and SO_2 and particulate emissions for the total period as well as for the years 2000, 2005, 2010 and 2010. The results are obtained by means of "what-if" analysis. For the scenarios with two criteria - cost and SO_2 emissions - the unit damage costs for the periods considered range from \$74-\$163 /ton SO_2 removed, and the best choices are scenarios Sc4-ac, Sc3-ac, Sc1-ac and

Sc3-ac, respectively. The use of three criteria would be better if the trade-offs between SO_2 and particulate emissions were known, which was not the case for this study.

The assessment of sustainability requires not only information about the emissions, but also assessment of the pollutants' influence on the environment. Since DECADES can calculate emissions but not dispersion, the RAINS model, a product of IIASA, was applied to the Bulgarian electricity sector in order to assess the SO_2 and NOx emissions and abatement costs, corresponding deposition fields and their influence on critical ecosystems. The deposition fields were obtained considering only Bulgarian emission sources but including the impact on neighbouring countries. RAINS permitted the construction of “emission vectors" to assess depositions on the basis of the DECPAC generated emissions. It was established that the sulphur and nitrogen deposition over Bulgaria from the TPPs in the scenarios does not exceed the critical levels for all considered cases.

The emissions and respective depositions obtained from DECPAC and RAINS were compared for years 2000, 2005 and 2010 and for all scenarios. Table 3.4 presents the SO_2 emissions for the cases without control (wc), new TPP controlled (nc) and all TPP controlled (ac). Table 3.5 – compares the respective deposition values.

The absolute relative error varies between 1.8 and 18.4% for emissions and between 4.5 and 16.5% for deposition, which is a good agreement between the RAINS and DECPAC results.

On the basis of the results obtained the, following strategy for the Bulgarian electricity sector development till 2015 could be outlined:

- For the period 2000–2005 (or more precisely 2000–2003) scenario 3-ac (all controlled) is most reasonable. This is practically an extension of the present situation. The period could be characterized with a slow growth of the coal sector to offset the forthcoming shut down of the nuclear units 1 and 2 in 2003.
- For the period 2005–2010 (or more precisely 2003–2007) the application of scenario 1-ac (all controlled), is preferable. The growth of the gas and especially the coal sectors for electricity generation is the main characteristic of this period. Investment in two nuclear units of 600 MW each should be made. Nuclear units 3 and 4 should remain in operation through 2007.
- For the period 2010-2015 (or more precisely 2007-2015) scenario 3-ac (all controlled) is the best choice. This scenario includes also growth of the coal and especially in this case the gas sectors. The shut down of nuclear units 3 and 4 would be expected in 2007. A delay of this shut down depends on the possibilities for extended use of gas for electricity generation and the extent of CO_2 emissions growth. If the latter exceed the Kyoto norms, the nuclear option is preferable. It would then be required to put two small nuclear units of 600 MW each into operation between 2010 and 2015.

Table 3.4. Comparison of RAINS and DECPAC emissions of SO_2 [kt]

Year\Scenario	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
Model	AINS	DECPAC	RAINS	DECPAC	RAINS	DECPAC	RAINS	DECPAC
2000 - wc	1093	1220	1093	1235	982	1188	1050	1188
2005 - wc	1421	1444	1383	1561	1177	1329	1178	1330
2010 - wc	1280	1344	1424	1605	1450	1514	1329	1503
2000 - nc	1093	1235	1094	1255	982	1188	1050	1188
2005 - nc	1355	1261	1317	1261	1171	1246	1172	1247
2010 - nc	1223	1165	1354	1277	1429	1335	1300	1327
2000 - ac	875	1001	875	1001	786	963	840	965
2005 - ac	1084	1022	1055	1022	973	1010	939	1011
2010 - ac	979	944	1074	965	1144	1083	1042	1089

Table 3.5. Comparison of RAINS and DECPAC generated mean SO_2 deposition ($mg/m^2 \cdot a$)

Year\Scenario	Scenario 1		Scenario 2		Scenario 3		Scenario 4	
Model	RAINS	DECPAC	RAINS	DECPAC	RAINS	DECPAC	RAINS	DECPAC
2000 - wc	656.0	732.3	656.0	741.3	589.4	713.0	630.2	713.0
2005 - wc	852.9	866.7	830.1	936.9	706.4	797.7	707.1	798.3
2010 - wc	768.3	806.7	854.7	963.4	870.3	908.7	797.7	902.1
2000 - nc	656.0	741.3	656.6	741.3	589.4	713.0	630.2	713.1
2005 - nc	813.3	756.8	790.5	756.8	702.8	747.8	703.4	748.5
2010 - nc	734.1	699.3	812.7	766.5	857.7	801.2	780.3	796.5
2000 - ac	525.2	600.8	525.2	600.8	471.8	578.0	504.2	579.2
2005 - ac	650.6	613.4	633.2	613.4	562.4	606.2	563.6	606.8
2010 - ac	587.6	566.6	644.6	579.2	686.6	650.0	625.4	653.6

4. CHINA

CHINA CASE STUDY OF DECPAC PACKAGE APPLICATION

4.1. Introduction

Since 1993 the International Atomic Energy Agency has organized many activities on comparative assessment of different power generation technologies for its Member States. These activities help the IAEA's Member States, especially developing countries, to enhance their capabilities for making comparative assessments of their electricity systems and rational planning of system expansion with not only economic but also environmental and health factors being taken into account. In order to master the relevant methodologies and tools, in 1997, a national team was established in China to carry out case studies using the IAEA's DECPAC and WASP-IV models under an IAEA Research Contract No.9525/RBF. The team was mainly composed of experts from the China Institute of Nuclear Industry Economics and the Institute of Energy Research, State Development & Planning Commission.

As China is a big country, its economic development and primary energy resources differ from one region to another. So it is difficult to conduct a comprehensive assessment of different generation technologies and make a power system expansion study for the whole country. In this case, our team conducted power system expansion studies for selected provinces in China, including the Guangdong and Shandong Provinces. This Executive Summary highlights results of the case study for Guangdong that was supported by the China Guangdong Nuclear Power Holding Corporation and the Planning Division of Electric Power Bureau of Guangdong Province. During the studies local experts from the provinces gave great support to the team in terms of basic information and data collection. The objectives of this study were as follows:

1) To master the IAEA's methodologies and tools for comparative assessment of different generation technologies;
2) To seek best options in the expansion of these provinces' power systems from the viewpoint of sustainable development; and
3) To investigate the role of nuclear power and assess the competitiveness of this technology against other generation technologies in these provinces.

4.2. Background

The Guangdong Province is located in the south of China and has a land area of 177,900 km^2. In 1997, the population in Guangdong was 70.14 Million, of which rural population accounts for 69%. The average population growth rate in the province during 1991~1997 was 1.7% which is higher than the national average.

The economy in Guangdong has developed at a very high rate since the policy of reform and opening to the outside world was adopted in China. Its GDP grew from 24.9 Billion YUAN (RMB), in 1980, to 156 Billion YUAN, in 1990, with an annual average growth rate of 12.3%. Guangdong's economy developed even faster in the 1990s'. Its GDP reached 731 billion YUAN in 1997 and the annual average growth rate was 16.7% from 1990 to 1997. Now Guangdong's economy takes the first position among all the provinces, municipalities and autonomous regions in China's mainland

Although there are rich mineral resources in the province, its coal resources are limited. According to statistical information, the proven coal reserves for the province are 668 Mt, only 0.1% of the nationwide total. Total energy production and primary energy consumption in the province during 1990~1997 are shown in Table 4.1 Given that provincial energy production cannot meet local demand, about 30 ~ 40 Mt of coal and crude oil must be imported each year from other provinces and the international market.

The environmental situation in the Guangdong Province has become increasingly worrisome, even as great progress has been made in social and economical development. There has been very serious air pollution, acid rain and solid waste pollution in recent years and the ecological environment has deteriorated generally. Therefore, great attention must be paid to environmental protection in planning future social and economical development, especially power system expansion, in the province.

Since the 1980 s the power industry in Guangdong has developed rapidly. Installed capacity grew from 2.81 GW in 1980 to 28.13 GW in 1997 with an annual growth rate of 14.5%; on average 1.49 GW of installed capacity was added each year. The historical data on installed capacity and electricity generation in Guangdong are shown in Table 4.2, while Table 4.3 shows the changing capacity mix in the province.

Table 4.1. Historical data of energy production and consumption

	1990		1993		1995		1997	
	Produ.	Consum.	Produ.	Consum.	Produ.	Consum.	Produ.	Consum.
Total (Mtce)	10.06	40.64	16.14	49.84	26.23	61.48	40.79	79.53
Coal (%)	63.1	56.5	42.1	58.3	29.1	56.4	14.7	54.2
Oil (%)	7.0	35.3	31.1	33.0	35.5	28.5	49.7	30.1
Gas (%)					0.5	0.2	10.9	0.4
Hydro (%)	29.9	8.2	26.8	8.7	34.9	14.9	24.7	15.3
Total (%)	100	100	100	100	100	100	100	100

Table 4.2. Historical data of installed capacity and electricity in Guangdong

Year	Capacity (MW)	Electricity (TW·h)
1980	2811	10.92
1985	3789	16.73
1990	8281	34.40
1995	22718	82.11
1997	28126	98.12

Table 4.3. Shares of different units in total installed capacity (%)

Year	Hydropower	Coal+Oil+Gas units	Nuclear	Total
1980	59.9	40.1		100
1985	58.7	41.3		100
1990	32.4	67.6		100
1995	20.5	71.6	7.9	100
1997	17.8	75.8	6.4	100

4.3. Solutions of the Guangdong Electric System Expansion

This study analysed five options for Guangdong electricity system expansion. Among them 4 options were consistent with the High Scenario of economic growth (i.e. 9% per year) and one with the Low Scenario (7% per year). The fixed configuration of the electricity system during the study period is the same for all options. Table 4.4 shows the installed capacities of the fixed system in Guangdong's power system expansion including existing units and committed additions and retirements.

Table 4.4. Installed capacities in fixed system of expansion planning (MW)

Year	Hydro	Coal	Oil	Nucl.	Total
1999	5159	12101	8780	1800	27840
2000	5238	13111	8780	1800	28929
2005	5872	13681	7501	3800	30854
2010	9580	13341	4070	3800	30791
2015	10840	10641	3262	3800	28543

Table 4.5 shows the cumulative new added capacities of the variable system and Figure 4.1 shows the optimum electricity generation mix for the province under the reference case assumptions. From the solution one can see that total installed capacity and total generated electricity for the Guangdong power system will reach 47550 MW and 232 TW·h respectively in 2010, and 67640 MW and 325 TW·h respectively in 2015. The solution of Option 1 illustrates that a new nuclear unit can be accepted in the optimizing process in 2006.

Under Option 4, a revised optimum solution, called the Realistic Option, was developed with two changes in assumed constraints compared with the reference case. Specifically:

1. The first two nuclear units were assumed to be built in 2008 and 2009, the second two nuclear units in 2011 and 2012 and the third in 2014 and 2015, respectively. This option was designed to be consistent with the resources and capability of Guangdong Nuclear Power Holding Corporation and the possible time schedule required for project approval by state authorities; and

Table 4.5. Cumulative capacity of variable system by year in Option 1 (MW)

Year	VG31	Zhuhai	VG62	VG63	Coal total	LNG	GAS	Gas total	VGN1	Total
2005	300	1200	1200		2700					2700
2006	300	1800	1800		3900				1000	4900
2007	900	2400	1800		5100				2000	7100
2008	900	2400	3000		6300	330		330	3000	9630
2009	900	2400	5400		8700	330		330	4000	13030
2010	900	2400	7800		11100	330	330	660	5000	16760
2011	900	2400	9000		12300	660	990	1650	6000	19950
2012	900	2400	12000		15300	660	1650	2310	7000	24610
2013	900	2400	13200	1800	18300	1320	1980	3300	8000	29600
2014	900	2400	14400	4800	22500	1320	1980	3300	9000	34800
2015	900	2400	14400	4800	22500	4620	1980	6600	10000	39100

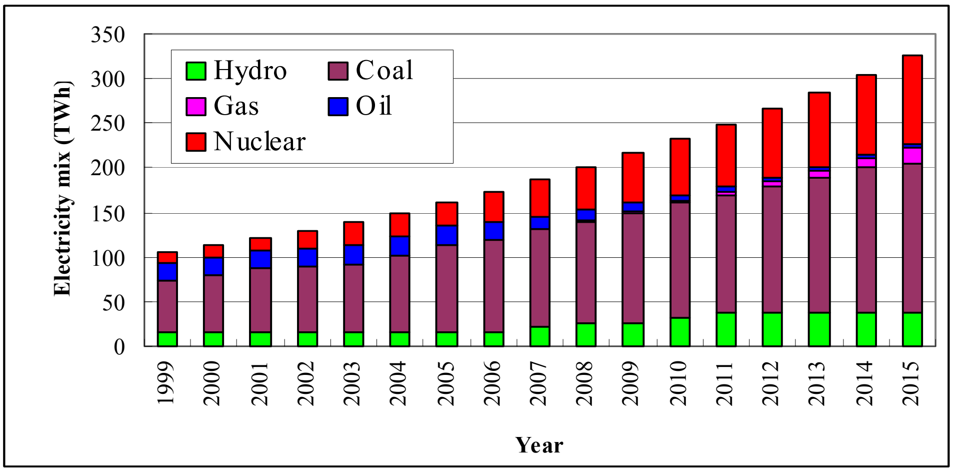


Figure 4.1. Electricity mix generated in Guangdong in Option 1.

1. In this option the domestic coal supply would reach 59 Mt in 2010 and 77Mt in 2015, instead of original values of 49 and 55Mt, respectively. In addition, the construction period of coal units VG62 and VG63 were shortened from 6 to 5 years and the expenditure schedules during construction period was revized.

In Tables 4.6 through 4.8, the Realistic Option is compared with an optimum solution prepared under the assumption that no new nuclear power units could be built in the province.

Table 4.6. Comparison of capacity mix in variable system expansion between Options 2 & 4 (MW)

	Fuel type	2005	2010	2015
Option 2 (No New- NPP Option)	Coal	2700	15900	33480
	Gas	-	990	6600
	Nuclear	-	-	-
	Total	2700	16890	40080
Option 4 (Realistic Option)	Coal	2700	13500	28500
	Gas	-	1320	4950
	Nuclear	-	2000	6000
	Total	2700	16820	39450

Some interesting conclusions can be drawn from these comparisons. For example, the province would cumulatively need 765 Mtce of coal from 1999 to 2015 to produce electricity in the High Scenario, if Guangdong does not further develop nuclear power after the Lingao NPP is completed in 2003. Since the province could only supply less than 100 Mtce of local coal during that period, about 87% of electricity sector coal requirements would have to be purchased from other provinces or abroad. However, if Guangdong expanded its power system according to the optimized solution of the realistic option (Option 4), total coal consumption of the system would be only 70 Mtce and no imported coal would be needed during the planning period (up to 2015). This is a significant energy substitution for Guangdong Province, which is about 2000 km away from main coalfields of China.

Further developing nuclear power would bring great environmental benefits to Guangdong Province. With fewer coal units installed in the province in Option 4, the discharged pollutants from Guangdong's power system would be reduced. Compared with Option 2 (No-NPP Option), the system would reduce its airborne emissions from 1999–2015 by 50 Mt C-equivalent of CO_2, 92 kt of SO_2, 467 kt of NO_x and 76 kt of particulates in Option 4 (Realistic Option). The reduction of SO_2 and particullates in both options is caused by the retirement of small and inefficient coal units and the assumption that new coal units be equipped with desulphurization devices. If no desulphurization measures are taken and no new nuclear units built in the planning period, SO_2 emission from Guangdong power sector would steeply rise from 405 kt in1999 to 1540 kt in 2015.

Table 4.7. Comparison of electricity mix between Option 2 & Option 4 (TW·h)

	Fuel type	2005	2010	2015	1999-2015 cumulative
Option 2 (No New- NPP Option)	Hydro	16.6	31.5	36.9	416.3
	Coal	97.1	164.7	237.6	2242.4
	Oil	20.8	6.5	5.0	233.9
	Gas	-	2.7	19.0	58.8
	Nuclear	27.0	27.0	27.0	409.3
	Total	161.6	232.3	325.5	3360.2
Option 4 (Realistic Option)	Hydro	16.6	31.5	36.9	416.3
	Coal	97.1	149.7	201.7	2059.7
	Oil	20.8	6.4	4.2	231.4
	Gas	-	3.5	13.1	52.0
	Nuclear	27.0	41.2	69.6	601.0
	Total	161.6	232.3	325.5	3360.1

The study showed that a nuclear unit would be economically competitive against coal-fired power in Guangdong if its overnight capital cost were about 1100 US$/kW. However, it is almost impossible to introduce nuclear units with this cost level. So the key point to developing nuclear power further in China must be cost reduction, for example by realizing the localization and standardization in nuclear unit construction.

Apart from the above conclusions, the study also indicated that the CCGT units would be accepted in the optimizing process by the Guangdong electricity system, and mainly dispatched as middle-load units.

4.4. Conclusions

Final results of the Guangdong Study gave strong support for a new nuclear power program in Guangdong. The province has submitted a feasibility study report on its new nuclear project to the central government and the project is awaiting approval.

Table 4.8. Comparison of discharged pollutants between Options 2 & 4

	Pollutant	2005	2010	2015	1999-2015 Cumulative
Option 2 (No New- NPP Option)	CO_2 (Mt.C-equ.)	32.7	48.7	69.4	701
	SO_2 (kt)	527	531	458	8504
	NO_x (kt)	354	472	657	7070
	Dust (kt)	192	209	195	3315
	Solid waste (Mt)	8.4	12.61	16.9	176
Option 4 (Realistic Option)	CO_2 (Mt.C-equ.)	32.7	44.6	59.5	651
	SO_2 (kt)	527	530	460	8412
	NO_x (kt)	354	434	566	6603
	Dust (kt)	192	202	183	3247
	Solid waste (Mt)	8.4	13.1	19.5	185

It should be noted that the IAEA's activities on comparative assessment of electricity generation technologies, and the dissemination of IAEA methodologies and tools are very helpful to Member States. Electricity system analysts in many Member States have been trained to conduct case studies using these tools. These case studies have practical functions in the relevant decision-making processes.

Most of the IAEA's member states are developing countries, with rapid rates of social and economic development and quickly growing power demands. How to develop their power systems consonant with rational use of energy resources, economic development and environmental protection is a major concern in those countries. On the other hand, GHG emission and the climate change are a serious challenge not only to the region but also to the whole world. The IAEA could continuously play an important role in providing Member with relevant tools for devising appropriate development strategies in the power sector.

5. CROATIA

CASE STUDY FOR “CROATIAN ELECTRICAL ENERGY SYSTEM ON COMPARING SUSTAINABLE ENERGY MIXES FOR ELECTRICITY GENERATION"

5.1. Introduction

This Executive Summary describes the results obtained under the Research Contract titled “Case Study for Croatian Electrical Energy System on Comparing Sustainable Energy Mixes for Electricity Generation” that was conducted as part of the IAEA’s Co-ordinate Research Programme (CRP) on Case Studies on Comparing Sustainable Energy Mixes for Electricity Generation.

The purpose of the project was to provide an objective analysis of possible power system development options and compute the corresponding air pollutant emissions. The main incentive for joining the interregional DECADES project coordinated by the Agency was to learn the methods for comparative assessment of environmental impacts of various power producing plants and their fuel cycles, as well as of power system expansion strategies.

The goal of the project was to determine the most appropriate strategies for development of the Croatian energy and electricity system, i.e., strategies that would be cost efficient, provide safe energy supply and comply with national requirements for environmental protection. The DECADES Tools were used to meet the goal of project. The DECADES study for Croatia was conducted by the faculty of electrical engineering and computing, in the Department of Power Systems, at the University of Zagreb.

5.2. Work Done on the Project

In the first year of Croatia’s CRP participation (1998), improvements were made to bring the DECADES country specific database (CSDB Croatia) up to a satisfactory level, so that these ultimately contained reliable data associated with different energy chains and high quality data specified for the electricity generation system. .

Much attention was given to plant- and system-level analyses. A large number of scenarios were defined to analyse many constraints in the process of optimization. For each scenario, the optimal capacity and generation mixes were identified and the resulting atmospheric emissions were calculated. Various emission abatement technologies were analysed and their impact on power plant performance observed.

In the second year of the project, research work focused on deriving external costs of electricity generation using generally available methodologies. The most comprehensive methodology for estimating external costs of energy chains, the impact pathway methodology developed within the ExternE project, was chosen for studying external costs in Croatia. External impacts associated with candidate power generating technologies in Croatia-specific conditions were estimated using the impact pathway methodology.

A detailed damage cost estimation was made for impacts from existing power plants in Croatia, based on values established by literature review both for exposure-response functions and monetary costs, the costs being adjusted for Croatia based on a ratio of purchasing power parity GDP. The costs attached to public health damages caused by the operation of thermal power plants in Croatia were calculated, with the average cost per kW·h produced equal to 1,85 eurocents/kW·h, and the highest costs, 7,45 eurocents/kW·h, associated with the coal fired TPP at Plomin. These external costs calculated for Croatia were lower than the average calculated EU values because the number of people exposed was lower and because the costs assigned to the different health impacts were lower.

Approaches were also reviewed for internalizing the estimated external costs of various electricity generating technologies, i.e. including externalities in the total objective cost function. The DECADES study for Croatia then analysed how internalization of external costs would affect the optimal mix of energy sources and the optimal long-term capacity expansion plan for the Croatian power system.

In the third year of the project, a more detailed damage cost estimation was made for the health impacts of power generation from existing and future power plant locations in Croatia. Rather than relying on default values available in the literature, as in the previous year, this effort sought to model and to calculate the local dispersion of pollutants, linking incremental concentrations of various air pollutants to corresponding population distribution density, and assigning a monetary value to the resulting impacts. A GIS (Geographic Information System) software was used, coupled with a relational database and attached to the map of Croatia, in order to accommodate the more comprehensive and highly site specific nature of this analysis. Location specific meteorological data were only partially available, so local impacts could be estimated only for Zagreb, but regional dispersion analysis provided a range of damage costs for Croatia for a hypothetical plant.

Damages linked to coal power plants were much larger than those linked to gas fired facilities, since the latter are responsible only for NO_x emission and nitrates. The largest share of damages is due to mortality. At the local level the highest damages are attributable to particulate matter, while sulphates and nitrates produce the greatest damages at the regional level. The range of damage costs for the whole of Croatia (population 5 million people) varies from 0,7 to 3,6 eurocents/kW·h for the candidate coal power plant and from 0,1 to -0,6 eurocents/kW·h for the candidate gas power plant. Damage costs for SO_2 equals 829 E/t, for NO_x via nitrates 727 E/t, and for particulates 3.168 E/t.

With location specific data for pollution dispersion, it was possible to estimate the health and other impacts associated with existing power plants in Croatia, and aggregate these values to determine the overall impacts for the whole Croatian power system. It was also possible to calculate the total costs associated with each power plant analysed, the plants' operating costs/kWh, total public health costs by county, and the contribution of each plant to total external costs in a county. Moreover, cost-benefit analyses were carried out for various emission abatement techniques and for optimal site selection for new power plants.

5.3. Case Study Findings

Calculated external costs can be applied in a variety of environmental policy case studies. One of case study conducted here considered the effects of including external costs in power system expansion planning. Internalization of external costs was made for the reference scenario of electricity consumption till 2030. Two marginal cases were observed, one with no constraint in natural gas supply (RS_05, or *max. gas*) and the other one with very limited natural gas availability (RS_08, or *min. gas*). External costs were added to the variable costs of candidate power plants in each of those two cases.

Specific findings drawn from these expansion scenarios include:

1) Gas-dominated options have the lowest CO_2 emissions, due to high conversion efficiencies of gas combined cycle plants (up to 50%), as well as low SO_x and particulates emissions. Emission levels crucially depend on the share of coal in the electricity generation mix. Presence of nuclear plants in the optimal solution reduces CO_2 emissions most successfully.
2) Power system expansion that includes nuclear power is the most environmentally friendly. Among the analyzed cases, there is no solution that could reduce CO_2 emissions till the year 2012 by 5% relative to the 1990 value. In the reference electricity consumption scenario, only the case with three nuclear units (3x600 MW) could substantially reduce CO_2 emissions and keep them below a certain value in the long run. In other words, there is no possibility to achieve the Kyoto requirement in such a short time. In the long run, however, nuclear power seems to be the only solution to reduce and "freeze" CO_2 emissions.
3) Renewable energy sources can also reduce the level of CO_2 emissions, but cannot reduce the required installed capacity of thermal units. Estimated potential of renewable sources for electricity generation vary between 3500 GW·h/year in a moderate projection to 6000 GW·h in the most optimistic, where they would account for 16-20% of total generation forecast for 2030. With maximal deployment of renewable, reference scenario emissions in 2030 could be 30% lower; with cumulative emissions from 2001 to 2030 perhaps 15% lower.

This exercise showed that external costs due to airborne emissions (particulate matter, SO_2 via sulphates and NO_x via nitrates) could influence both the optimal capacity mix and operation of the power system. If the higher estimate of calculated damage cost for the candidate coal and gas power plants were added to their already internalised production costs and if the appropriate external cost for nuclear power plants is added too, optimal capacity mix shifts to nuclear power plants.

However, results indicate that adding external costs only to candidate power plants does not guarantee better environmental performance of the system, since it might happen that the existing, typically less efficient and more polluting facilities, are more frequently dispatched because they gain priority in the economic loading order. Therefore, the next step in our research should be to examine impact of external costs on power plant dispatch in the system, and consequently on power system emissions.

However, despite these findings, Croatian mid-term electricity supply seems likely to be based on natural gas and coal. The future electricity supply mix will depend on the availability of both energy sources and locations for new power plants. Since primary energy reserves in Croatia are scarce, the future energy mix for electricity production will largely be determined by the international market.

The scientific results of the presented research are two-master's theses at the Faculty of Electrical Engineering and Computing - Department of Power Systems completed in the year 2000. The titles are: "Environmental Damage Costs Caused by Electricity Generation" and

“External Costs as Criteria in Selection of Thermal Power Plant Location and Technology”. Research based on this CRP resulted also in great number of scientific and professional papers published in Journals and International Conferences.

6. CUBA

IMPLEMENTATION OF COUNTRY SPECIFIC DATABASE (CSDB) AND COMPARATIVE ASSESSMENT OF OPTIONS AND STRATEGIES FOR ELECTRICITY GENERATION

Cuba is an island surrounded by around 4,195 smaller keys and islets, totalling a surface of 110,992 km^2. The climate is subtropical moderate with two well-defined seasons: Dry and Rainy. The average annual precipitation is 1375 mm and the average temperature is 25 °C (76 °F). The population is 11,287,365 inhabitants. Currency is the Cuban Peso with an exchange rate of One U.S. Dollar equal to one Cuban Peso. The GDP in 1999 was 15663.7 Billion pesos (referred to 1981 constant prices).

Cuba is poor in primary energy resources. The main energy sources for electricity generation in the country are: crude oil, fuel oil (imported), natural gas, hydro, sugar cane bagasse and wood. Domestic crude oil is heavy with high sulphur content, yet constitutes about 30% of the total oil used for electricity generation in 1999. Natural gas appears as associated gas with high H_2S content and its reserves are limited. The estimated hydro potential is roughly 650 MW, but only 55 MW are currently in use due to financial and environmental considerations. Sugar cane bagasse is a by-product of sugar cane production. It constitutes an important national energy source with a participation of around 20% in national energy consumption.

Sugar factories account for about 827 MW of installed capacity, which generates about 73% of their own electricity consumption. Almost 93% of the electricity generated in 1998 came from conventional oil steam boilers, while 6.2% came from biomass (bagasse) plants, and the remaining 1.3% from Hydro and gas turbines (excluding non-grid co-generation and isolated plants).

Cuba joined the DECADES Project in 1996 with Research Contract CUB-9192/RB. A Country Specific Data Base (CSDB) was created ultimately containing the information needed to perform national electric system expansion studies. At the chain level, some data were missing for front- and back-end technologies, but necessary default data were obtained from the Reference Technology Database (RTDB) and elsewhere.

A Base Case was defined for the electricity system expansion. The influence of expansion parameters and reliability criteria were analyzed and a Reference Scenario was defined. Taking into account the demand growth forecasts of different sectors three main growth scenarios of electricity demand were established: Low, High and Rupture Scenario.

A broad range of expansion candidates was analyzed. The main considerations for the evaluation of expansion candidates were cost, technology type and energy resource availability. Modernization programs of some units and firm projects was considered. The study was performed for the period 1997–2015. A discount rate of 12% was used and the cost of unsatisfied demand was set at $1.9/kW·h. Line losses (LOLP) were limited to 0.5%, reserve margins were considered between 15%–45% of annual maximum demand, and spinning reserve requirement was set at 321 MW. The economic loading order calculated by DECPAC was used to dispatch the units during operation. No fuel escalation cost was considered during the study period, owing to a lack of appropriate data. The number of units for some expansion candidates was limited throughout the study period due to constraints in construction capabilities, construction period, and availability of energy resources.

As expected, the optimal expansion plan for each scenario shows that, as electricity demand increases from Low to Rupture Scenarios, so does the overall investment cost, while O&M costs and fuel costs fall as a share of total cost. In the Low Scenario, CO_2 emissions are reduced by 11% in relation to the 1997 level. In Reference Scenario, CO_2 emissions exceed the 1997 level only at the end of study period due to incorporation of a coal power plant (See Fig.6.1). In the High and Rupture Scenarios, the increase in CO_2 emissions is mainly due to incorporation of coal-fired power plants. Particulate emissions increase in all scenarios, because in Low and Reference Scenarios some BIO plants are incorporated and for the others scenarios, in addition to BIO some coal plants will start up.

If nuclear power is replaced by a conventional oil steam boiler (OSB) the total system cost during study period would increase by $330 MM, and the NPP 15% of (1997) avoided CO_2 emissions would also be lost to the Cuban electricity system. With such a replacement in 2001, the reserve margin would reach 55%, since there would be more power plants on the system than needed, and large plants would generate at a 50% capacity factor of. The added cost to the system would be $176 MM, and emissions would also.

Sensitivity analyses were performed on the installation of various pollution abatement technologies. The DECADES Control Device Sub Module (CDSM) was enhanced and a test case was executed to validate computations performed for all abatement technologies. The installation of three abatement technologies to major power plants in the Reference Scenario were estimated to cost around $650 MM in 1997, plus $250 MM annually 1998–2000, plus an average of $40 MM per year for incremental operating costs. Nevertheless the emissions reductions would be significant.

Mitigation options were evaluated in mitigation scenarios. From the emissions reduction point of view the best mitigation option is a combination of sugarcane biomass with a NPP (Scenario II). It costs 6% more than Scenario III (a mix scenario with all mitigation alternatives) but reduces 2.1 million tonnes of CO_2 emissions. The reduction cost of the Scenario II is thus $1.07/tonne CO_2. In Scenario II the carbon intensity (tonnes CO_2/GW·h) decreases by 43% in relation to the Base Line Scenario and it is reduced twice with regard to 1997 (See Figure 6.2).

The three mitigation scenarios forecast levels of CO_2, SO_2 and particulate emissions at the end of the study period that were lower than 1997 levels, even though GDP per capita was expected to increase by an average of 3.5% per year, electricity demand was forecast to grow 14% during the period (4.1% on a per capita basis) and generation by 33% (3% on a per capita basis). Fossil fuel use should fall by 20% in the Base Line Scenario and by 108% for Scenario II with regard to base year. The participation of renewable sources will increase by 13% in Scenario III and 43% in Scenario I.

The main contributor to GHG emission reduction in all of these various mitigation scenarios would be nuclear power, though renewable resources also have an appreciable s potential for reducing GHG emissions. CO_2 emissions per USD of GDP for all scenarios is forecast to fall by 32–61%, while the mitigation scenarios CO_2 emissions per capita should fall by some 10–26%. In Scenario II (the best mitigation scenario), SO_2 emissions per GW·h fall by 50% from the base year by the end of the study, while CO_2 emissions fall by 2.1 times to 426 Tonnes CO_2/GW·h in 2015. This level of carbon intensity for electricity generation is comparable to levels reported in Spain and Portugal. In the Base Line Scenario CO_2 emissions per GW·h drop 23%, largely through efficiency improvements in fossil-fired plants.

For a preliminary external costs estimation, the DECADES tools were extended with site-specific information, population and meteorological data. This study shows that SO_x emissions are the most important contributor to the damage costs. Installation of SO_x abatement technologies was found to be economically justified to reduce some 80% of these emissions. For NO_x and particulate emissions, the damage costs are bigger than abatement costs for some 65% and 57% of the emissions respectively.

The work carried out in cooperation with the national electricity utility to draft an expansion plan during 2000 showed the capabilities of DECADES to support the analytical requirements of decision makers. To support future studies, improved data would be needed to characterize facilities at the front- and back-end of the energy chain. Additional expansion cases could also be evaluated. Further studies need to be complemented by detailed energy balance studies (using ENPEP). (MAED-1 was used in this study to prepare an electricity demand forecast for the country and the Decision Analysis Module (DAM) was used to evaluate different alternatives taking into account economic and environmental aspects.)

The work carried out in the preliminary estimation of external costs of electricity generation highlighted the absence of impact cost data, adequate response functions and appropriate tools to do it. The EcoSense model should be adapted to the specific conditions of small countries like Cuba, or new tools should be developed to support such analyses.

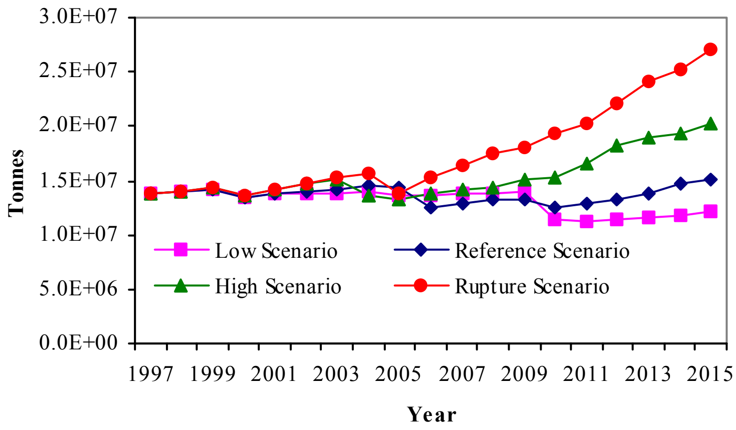


Figure 6.1. CO_2 emissions in economic scenarios.

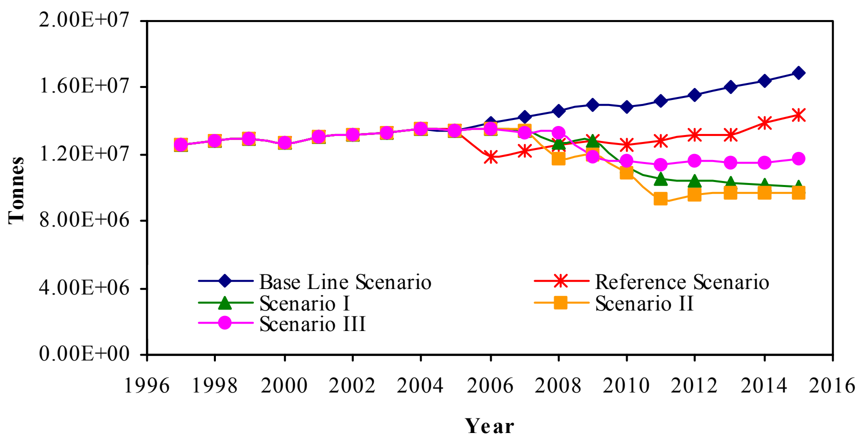


Figure 6.2. CO_2 emissions in mitigation scenarios.

7. EGYPT

COMPARATIVE ASSESSMENT OF ELECTRICITY SYSTEM POLICIES IN EGYPT WITH EMPHASIS ON ADDRESSING ATMOSPHERIC POLLUTION

Egypt has a rapidly growing population and a commensurately growing per capita energy demand. As a signatory of the United Nations Framework Convention on Climate Change, Egypt is making all efforts to comply with the UNFCC strategy to meet the challenge of increasing energy demand, while integrating environmental factors into national decision making and continuously improving environmental performance. In the electricity sector, a number of specific actions have been undertaken to help meet the demand for electricity while minimizing the resulting environmental impacts. These actions include:

- Improve power system efficiency by rehabilitating the oldest of existing power plants,
- Converting existing open-cycle units to combined cycle
- Introducing new combined cycle power plants
- Constructing modern 300 MW and 600MW units
- Rehabilitating and reinforcing the existing transmission network to minimize system losses

Other actions include the government's aim to increase electricity prices so that electricity consumers receive clear and correct price signals reflecting the economic cost of supply, and the initiation of energy conservation and demand side management programs. Over-all, environmental considerations have become a major issue in calculating the feasibility of any new additions to the electricity system.

The study for the DECADES project focused on developing an inventory of greenhouse gasses (GHGs) associated with energy activities in Egypt, and analysing policy measures and technologies that could be applied to decrease the GHG emissions from the base scenario by some 25% to 50%. A set of performance indicators was developed against which implementation of the national strategy measures aimed at reducing GHG emissions could be evaluated.

In the study, GHG emissions were calculated for full energy chains for electricity generation (i.e., including all steps from resource extraction, processing of fuels, transportation, electricity generation and waste disposal) taking into account the emissions during construction, operation and decommissioning of energy facilities. In addition, a mathematical model was developed for assessing GHG emissions from hydropower in Egypt.

A variety of primary energy resources is available in Egypt, with varying potentialities. The most important of these are oil, natural gas, coal, hydropower, solar, biomass, geothermal and wind. Limited deposits of uranium and thorium also exist. Heavy fuel oil and natural gas are the most important fuels for electricity generation in Egypt. Most of the existing steam power plants are dual fired using either mazout or natural gas as the primary fuel. Hydropower currently accounts for 20% of Egypt's electricity generation. In the study, an assessment was made of the environmental and social impacts of the Aswan High Dam along with an evaluation of the full energy chain emission of GHGs from the hydro chain. The study also assessed the potential for geothermal resources in Egypt: there are some 85 existing geothermal springs and wells with temperatures ranging between 30-70 degrees C and located mainly in the western desert and Sinai.

In this study, the Integrated Resource Planning (IRP) approach was used to evaluate supply side and demand side resources on an equal basis and identify the optimum mix among these resources. The study analyzed two sets of alternatives for meeting the electricity needs of the country. One set of plans took into consideration the effect of including nuclear, coal and wind units. The second set of plans considered the inclusion of non-traditional generation resources (such as wind) and demand side management options into the overall resource plan in terms of their economic and environmental benefits. The demand side management plan included the following programs:

- Compact fluorescent lamps for residential consumers
- Efficient lighting for public uses
- Electronic ballasts for commercial lighting
- Energy conservation in government buildings (lighting and air conditioning)
- Energy conservation in industry

Taking 1998 as the base year of the study, the EGEAS and DECPAC models were used to develop assess a number of alternative power system expansion cases and to construct from them a plan having the lowest total present worth of annual investment requirements. The expansion plans took into consideration that the installed reserves of the Egyptian power system must accommodate changes in the availability of the hydro generation units depending on irrigation requirements, scheduled maintenance, unplanned forced outages, daily and seasonal fluctuations in customer demand. A sensitivity analysis was performed to assess the impact of using the international price of fuel rather than its prevailing domestic price, i.e., 4.2 US$ per million BTU instead of 1.13 for natural gas, and 3.5 US$ per million BTU instead of 1.49 for heavy fuel oil.

In the study, more than 30 indicators were used to measure progress towards sustainable development in the country. The performance indicators for the energy sector included: fossil fuel consumption (primary energy), the physical amount of energy-related GHG emissions, energy-related GHG emissions per unit of energy delivered, energy-related GHG per unit of GDP, and energy-related GHG emissions per capita. The selected indicators were used as a measure of overall performance relative to targets and benchmarks for projections up to the year 2020.

When evaluating the first set of plans, the scenario using the nuclear and coal options was determined to be the most expensive option, while a coal-only scenario has the highest values for GHG emissions. The second set of plans indicated that the potential savings from the demand side management programs ranged from a 10% reduction per year as compared to the base year for the moderate scenario, up to 20% per year for the aggressive scenario. The optimum expansion plan also indicated that wind generation could be economically competitive when fuels are priced at the international level. In fact, using international prices for fuels resulted in the introduction of an additional 900 MW of wind farms.

8. HUNGARY

CASE STUDIES TO ASSESS AND COMPARE DIFFERENT ENERGY SOURCES IN SUSTAINABLE ENERGY AND ELECTRICITY SUPPLY STRATEGIES — THE CASE STUDY FOR HUNGARY

8.1. Introduction

Under the current research contract, case studies were conducted to provide insights into historical greenhouse gas (GHG) emissions in Hungary and to assess different options for mitigating future GHG emissions, in order to facilitate the preparation of a climate change action plan for the country. Well-known computer models like ENPEP and EFOM were used to examine what role different energy options might play in greenhouse gas emissions reduction in Hungary in the next 20 to 30 years.

8.1.1. The Hungarian Electric Sector

Since the country has few inexpensive or good quality energy resources, the Hungarian energy system is characterized by a high dependency on imports. Figure 8.1 shows how, since the 1950s, increasing energy demand is covered by an increasing reliance on imports. Serious consideration is given to the diversification of these imports in order to provide a safe energy supply.

The fuel structure of the Hungarian electricity sector changed considerably in the 80's, as the country’s first nuclear power plant began operation in 1983. Figure 8.2 shows the development of the national fuel mix from 1950 until 1998. Although the share of nuclear power has remained stable since 1992, nuclear power continues to play a decisive role in Hungary's power supply.

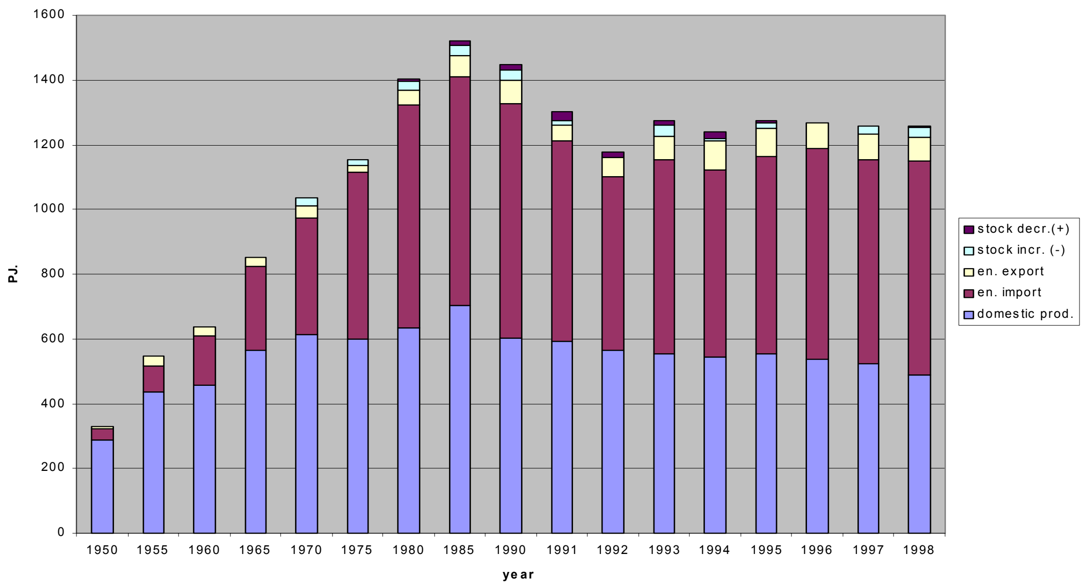
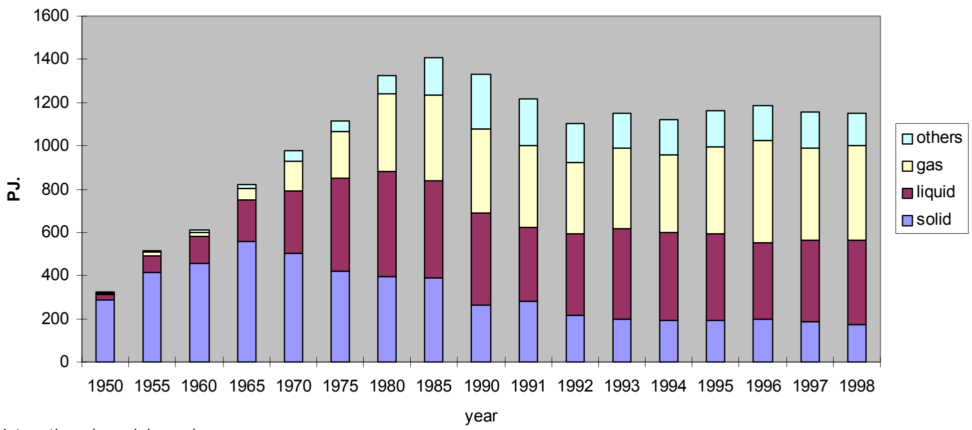


Figure 8.1. Structure of energy consumed by sources.



Note: others is mainly nuclear

Figure 8.2. Structure of Energy Consumed by Fuel Type.

8.2. Hungary's Participation in the UN FCCC

Hungary was one of the first countries to join the UN Framework Convention on Climate Change (UN FCCC), when the President of Hungary signed it in Rio de Janeiro in 1992, and the Parliament ratified it in the following year. The ratification instrument was deposited with the Secretary General of the UN in 1994. According to the subsequent Kyoto Protocol, Hungary must keep its anthropogenic greenhouse gas (GHG) emissions at 6% below the base level in the period of 2008-2012. While the base level for most countries is the emissions level of 1990, Article 4.6 allows Central and Eastern European countries with economies in transition to select a different base year (or base period), to adjust for the effects of the economic crisis in the region in the second half of the 80's. This crisis led to political change, but also resulted in a great decline in economic activity and consequently in emissions by 1990. Using 1990 as a base year would thus be disadvantageous for these countries. Hungary selected the average annual emissions in 1985-1987 as its base level.

Table 8.1 provides an overview of the anthropogenic GHG emissions in Hungary during the period of 1985-1995, as determined according to approved IPCC methodologies. Emissions of GHG gases decreased until 1994, basically as a result of the economic recession, to a level 30% below the selected base level. However, since the economic growth rate is now almost twice that of the Western market economies, there could be a sharp increase in GHG emissions in the near future.

Although Hungary is still far from reaching the emission limits established under the Kyoto Protocol, it is important to take specific steps soon to stabilize or reduce GHG emissions.

Since power generation accounts for almost half of energy-related GHG emissions, the use of nuclear energy could play a decisive role. This study estimated the cumulative emission savings since 1983 due to the operation of the Paks nuclear plant as follows:

CO_2:	1 100 Mt
NOx:	2 800 kt
CO:	1 400 kt
Particulates:	2 000 kt
SO_2:	26 000 kt

Table 8.1. Fuel related CO_2 emissions in Hungary (kt)

Sector	Average of 1985-87	1990	1991	1992	1993	1994	1995
Energy	36928	29746	28520	27476	27575	26290	26431
Industry	10893	7893	6380	5131	5548	6306	6352
Transport	7741	8208	7383	7189	7141	7212	7001
Commercial	3403	3290	3959	3517	3822	3970	3946
Residential	16639	15125	15670	12196	12271	11453	11296
Agriculture	3132	2462	2120	1593	1499	1537	1519
Other	1353	1381	1224	1534	900	278	1022
TOTAL	80089	68105	65256	58636	58756	57046	57567

8.2.1. Model Runs and Results

The BALANCE and IMPACTS modules of ENPEP were used to evaluate the role that different energy options could in mitigating national GHG emissions in Hungary during the period 1998-2030. A reference case was established to represent the existing energy system and to reflect several ongoing government programs aimed at reducing specific energy consumption. The study examined two cases in terms of their associated potential for energy savings and the corresponding CO_2 emission reduction. In the first case, no extension of nuclear capacity was assumed. In the second case, two new 600 MW nuclear power plants were added to the system (in 2008 and 2009).

The primary difference in results between the two cases is that the use of new nuclear power almost entirely squeezes out the use of fuel oil around 2010. However, after 2010, the use of fuel oil gradually increases again to where, at the end of the study period, the level of its use is half of present levels. The use of coal is also far lower in the long run in the nuclear scenario. A further observation is that, in Case 1, the level of GHG emissions from the electricity sector gradually increases from 2004, while, in Case 2, the existing level of CO_2 emissions would not be exceeded until 2026, even with the forecasted increase in demand for electricity.

8.3. Conclusions

Although there are several programs and measures in Hungary to stabilize or to reduce anthropogenic GHG emissions (energy saving programs, afforestation, etc.), the present analysis indicates that nuclear power would be the main mitigation option for Hungary. Given that present economic growth rates will result increased pollution (including $CO_{2)}$, the emission reductions required by the Kyoto Protocol will not be fulfilled without the extensive use of nuclear energy. However, there are several barriers to the expansion of nuclear capacity. One barrier would be the high share nuclear energy would have in the power generation mix, because fuel diversification is a priority Hungarian energy policy. Another barrier is the high investment cost of nuclear. Finally there is the influence of independent environmental organizations, which oppose the operation of nuclear power plants.

9. INDONESIA

CASE STUDIES ON COMPARING SUSTAINABLE ENERGY MIXES FOR ELECTRICITY GENERATION IN INDONESIA

9.1. Introduction

This Executive Summary describes the results obtained from a study conducted during the period 1997 to 2000 by the Agency for Assessment and Application of Technology (BPPT) in Indonesia under the IAEA's Co-ordinated Research Programme (CRP) on Case Studies on Comparing Sustainable Energy Mixes for Electricity Generation.

The objective of this study was to design a long-term sustainable energy mix for electricity generation in Indonesia over the period 1995–2025 as an optimum result of the integration of factors affecting national economic growth, common energy technology, and environmental aspects.

The first year of the study focused on preparing a Country Specific Database (CSDB) that could be used to support comparative assessment studies conducted with the DECADES Tools. The second-year of the study focused on analysing the effect of the Asian economic crisis on electricity system planning in Indonesia. The third-year of the study used the Decision Analysis Module (DAM) to identify optimal energy mixes for electricity generation in Indonesia with due account given to energy, economic and environmental aspects.

9.2. Energy and Resources in Indonesia

In 1995 the total final energy demand for Indonesia was 3,340 PJ. Energy consumption in the residential and commercial sector had a dominant share accounting for roughly 41% of national energy demand, while the industrial and transportation sectors consumed 37% and 22%, respectively. Most of this demand was supplied by fossil fuels (oil, coal, and natural gas).

Fossil fuels also play a very important role in meeting the energy demand for electricity generation in Indonesia, though a number of other energy sources are also used, including: hydropower, geothermal, solar, wind, and biomass. The energy resources and potentials in Indonesia are described below.

Total oil resources in Indonesia are estimated at about 72 billion barrels, of which about 10.15 billion are proven and probable reserves (PERTAMINA, 1994). Under the assumptions of constant (1994) average annual production (some 547.0 million barrels/y) and constant (1994) prices, existing reserves should last for about 18 years.

In 1995, the total natural gas resources were estimated at about 266 TCF, of which 90 are classified as proven and probable reserves. More than 60% of the natural gas reserves are located offshore. If natural gas production is estimated to be about 3 TCF per year, the Reserve to Production Ratio (R/P) is around 30 years.

Total coal reserves are mainly located in Kalimantan and Sumatera and are estimated at about 36 billions tons, of which 24 billion tons are classified as measured and indicated reserves. At the end of 1995 the R/P of coal was estimated at about 450 years. Considering that the country has such large reserves of domestic coal, the Indonesian domestic steam coal demand is currently relatively small. However, the demand for coal is expected to grow significantly towards the end of the century.

Indonesia also has a large hydropower potential of 75.50 GW. However, only some 3% of the total hydropower potential, or 2.20 GW, has been utilized. Hydropower potential exists in some 1,210 locations with an estimated total electricity production of around 401,644 GW·h.

The total geothermal potential in Indonesia has been estimated at about 16.1 GW, some 44% being classified as reserves and 56% as resource. More than half of the geothermal l reserves are located in Jawa-Bali, but only 13% of the geothermal resources. The total installed geothermal capacity of the country is about 589 MW.

9.3. Electricity in Indonesia

Electricity generation in Indonesia is supplied by the State Electricity Company (PLN), which is responsible for the interconnected grid system, the decentralized system, as well as the Independent Power Producers (IPP) and auto-generation (captive power). PLN has dominated electricity supply in Indonesia. PLN's installed capacity increased at an average annual growth rate of over 12.%, from 4,080 MW in 1984 to 14,895 MW in 1995, while PLN electricity production increased from 13.75 TW·h to 59.40 TW·h, or about 14.% per year. By contrast, in the same period, the installed auto-generation capacity increased by approximately 6.6% per year, from 3,206.19 MW in 1984 to 6,538.81 MW in 1995.

Total demand for electricity was 54,988.91 GW·h in 1995. Most of this went to the industrial and household sectors with shares of 49% and 351% respectively. Most of PLN's electricity production was generated by fossil fuels. Total oil consumption for electricity generation in 1995 was 2,983,447 kiloliter or about 110.61 PJ. This oil consumption for electricity generation was contributed by HSD (58.83%), IDO (0.92%), and MFO (40.25%)

Jawa and Sumatra consumed the lion's share of the coal and gas used for electricity generation. For coal this amounted to some 5.5 MMt or about 122,32 PJ, some 87% of total national coal consumption. For natural gas Jawa and Sumatra electricity generation used a total of 220 MMCF or 222.4 PJ in 1995, some 89% of total gas consumption.

Indonesia experienced an economic crisis in 1997-1998. The crisis hit all sectors on the economy either directly or indirectly. It affected the buying-power of consumers, which led to a decline in industrial production sales. As a consequence, industrial production was reduced causing a decline in electricity consumption, a decline in other supporting sectors and a decrease in personal income. To reflect this economic recession the Business As Usual (BAU) scenario defined for this study utilized a zero growth rate in electricity demand for the year 2000. It also estimated that the economic condition of the country would fully recover, by 2010, and from then on the peak load would increase at an average rate of 7% per year.

9.4. Decision Analysis and Planning for Electricity Generation

The BAU projection of electricity demand has been adopted as an input for electricity supply optimization. In the study, five different scenarios were analyzed to elaborate a strategy for electricity supply:

9.4.1. Baseline Scenario (BAS Scenario)

In this scenario, the DECADES Tools were used to develop an electricity supply mix that optimized with respect to least cost. Since no pollution controls were implemented under the BAS scenario, this scenario is also the worst-case scenario with respect to the environmental consequences.

9.4.2. Environmental Impact Scenario (ENV Scenario)

This scenario took into account the environmental benefits and added costs associated with clean coal technologies. Investment costs for clean coal technologies were estimated to be about 20-30% more expensive than for conventional coal technology.

9.4.3. Gas Limitation Scenario (GAL Scenario)

In this scenario, domestic use of natural gas to fuel gas turbine and gas combined cycle power plants was constrained, in order to maximize profits from the export of natural gas.

9.4.4. Renewable Energy Scenario (REN Scenario)

This scenario was based on maximum utilization of renewable energy resources, specifically hydro, geothermal and biomass power plants.

9.4.5. Nuclear Power Plant Scenario (NUC Scenario)

In this scenario, nuclear power was considered as an option for future generation system expansion to reduce CO_2 emissions.

All of these scenarios had the same electricity supply mix in the base year, where electricity supply was dominated by oil-fired power plants (29%), followed by gas turbine (24%) and coal fired (24%) power plants, and the remaining 23% coming from renewable.

The BAS scenario was used to project electricity supply from 1995 to 2025. During this period, installed capacity from coal-fired power plants was estimated to increase by 10% per annum. By the end of the study period, coal fired power plants had a 78% share of total electricity supply. Renewable, consisting of hydro, geothermal and biomass power plants, had the second highest share of electricity supply with 14%. The remaining 7% share was generated by gas turbine power plants, while oil-fired power plants were phased out

The final goal of this electricity planning effort was to provide information to help to decision-makers determine energy policy. The decision-makers have to choose appropriate options among the available alternatives represented as scenarios, some of which have conflicting objectives (e.g. minimize cost and minimize emissions).

In the final year of the study, the Decision Aiding Module (DAM) Software Version 2.0 was used to aid in solving such multi criteria decision analysis problems. The methodology used by DAM is at the cutting edge of decision analysis. The ability to specify *imprecise trade-offs* (e.g. the ability to specify a range of damage costs rather than being forced to specify a single value) is an advantage that DAM has over other decision analysis tools.

The goal of the DAM analysis was to identify appropriate alternative scenarios for reducing air pollution emissions in a cost effective manner. The BAS scenario was specified as the basic scenario against which all other scenarios (i.e. ENV, GAL, REN, and NUC) were compared using the DAM software. So that the results of this study could be compared with those from a previous study done using the MARKAL model, the estimated costs and emissions from this study were discounted to a base year of 1995 at a discount rate of 10%.

The results of the multi-criteria decision analysis using the DAM software were that the Baseline Scenario (BAS) and Nuclear Scenario (NUC) would both be considered as potentially optimal alternatives. The other alternatives (Environmental (ENV), Renewable (REN) and Gas Limitation (GAL) Scenarios) could not be recommended for implementation because, over the reasonable range of unit damage costs for SO_2, NOx, CO and CO_2 emissions, these alternatives never outperformed the BAS and NUC scenarios.

10. FORMER YUGOSLAV REPUBLIC OF MACEDONIA

MAIN RESULTS FROM THE MACEDONIAN POWER SYSTEM DEVELOPMENT STUDY

Until 1991, the Macedonian Power System was an integral part of the European power transmission system. At present, it works isolated from the main portion of the UCTE network, connected only with the neighbouring power systems in the Balkans. However, being located in the central area of the Balkans, where the transmission systems cross from North to South and from East to West, the Macedonian Power System is expected to become an important part of the integral European system in the near future.

After independence, the level of electricity generation in Macedonia was just sufficient to meet the needs of the country. The electricity supply and demand structure for the year 1998 is given in Table 10.1. It is evident that the dominant contribution was from thermal power plants, which accounted for about 85% of total generation, while the rest was covered by hydro plants. Electricity imports were low, based only on functional electricity exchange between neighbouring electric power systems.

Table 10.1. Electricity supply and demand structure for the year 1998

Supply	(GW·h)	(%)	Demand	(GW·h)	(%)
Thermal	5,445	83.5	Household	2,555	39.2
Hydro	1,078	16.5	Industry	1,114	17.1
TOTAL	6,523	100.0	Metallurgy	1,437	22.0
			Commercial	540	8.3
			Losses	876	13.4
			TOTAL	6,523	100.0

The annual increase in electricity production between 1994 and 1998 was about 4.4%, and the available electricity generating capacity grew at an annual rate of 4.1%. At the same time, the net electricity demand grew by 3.5% per year. There are no indications that electricity consumption growth will fall in the coming years, especially given and the anticipated rapid growth of the national economy.

The electric power system in Macedonia now has only three fossil-fired power plants: Negotino, Oslomej and Bitola (three units), six large hydro plants and 15 small hydro plants (which for the sake of this study were grouped into one equivalent plant). During the period 1991 to 1998, the oil-fired power plant at Negotino operated at a very low level, while lignite-fired power plants operated at very high capacity factors. In fact, the lignite mines and power plants in Macedonia were achieving their maximum production possibilities during this time. A list of existing plants in the Macedonian power system together with their main characteristics is given in Table 10.2.

With the present power system, increasing demands for electricity can only be met by the oil-fired power plant at Negotino. Yet Macedonia should begin activities early in the 21st century, to compensate for the exhaustion of its lignite reserves that now fuel the existing thermal power plants. To inform this process, under the IAEA's CRP on Case Studies to Assess and Compare Different Energy Sources in Sustainable Energy and Electricity Supply Strategies, a research contract was established to conduct a Macedonian Power System Development Study, with a planning period from 2001 to 2020.

Table 10.2. Existing Power Plants in the Macedonian Power System

Thermal plants			Hydro plants		
Name	Netcapacity (MW)	Energy (GW·h)	Name	Netcapacity (MW)	Energy (GW·h)
1. Bitola 1	207	1,400	1. Vrben	12.8	38.9
2. Bitola 2	207	1,400	2. Vrutok	150.0	317.3
3. Bitola 3	207	1,400	3. Raven	19.2	38.4
4. Oslomej	109	750	4. Globocica	42.0	164.6
5. Negotino	198	1,200	5. Spilje	84.0	241.4
TOTAL	928	6,150	6. Tikves	92.0	135.6
			7. Small hydro	41.0	92.8
			TOTAL	441.0	1029.0

In this expansion plan study, the need for and the timing of new capacity was largely determined by the future of three the largest consumers of electricity in the country, namely: the metallurgy facilities at FENIMAK and JUGOHROM. The initial conditions for the load demand curve reflected the status of their demand, as did the three cases of electricity consumption and peak demand analysed in the study:

6,500 GW·h and 1,212.4 MW, assuming both FENIMAK & JUGOHROM are to be shut down;

7,000 GW·h and 1,305.7 MW, assuming only FENIMAK is to be shutdown; and

7,500 GW·h and 1,399.0 MW, without any shut downs.

Annual load demand growth rates were defined for 10-year time periods, i.e. 3.75% for 2001 through 2010; and 3.25% for 2011 through 2020. The following input data and assumptions were used in the study:

Load duration curves (LDCs) were based on actual hourly load data for the period from January 1991 through December 1998. Import/Export potential was considered through the interconnection with neighbouring power systems at a level of about 100 GW·h/year with maximum engaged power of 50 MW.

The existing hydropower plants and candidates were divided into two groups, HYD1 and HYD2. The HYD1 group consisted of the existing hydro power plants: Globocica, Spilje, Tikves, Vrutok and Kozjak (under construction; on-line in 2002), as well as the hydro candidates: Galiste and Cebren. The HYD2 group consisted of the existing hydro power plants: Vrben, Raven, Matka 1 (reconstruction) and Matka 2 (under construction; on-line in 2005), as well as the candidates: Boskov Most, Veles and Gradec. Probabilities for three hydro conditions (dry, normal and wet) were based on the average monthly inflows of hydro power plants for the period 1946-1996.

Thermal candidates for capacity expansion included rehabilitation of existing thermal power plants and new construction of two types of power plants: a 270 MW gas-fired combined cycle plant with an efficiency of 57.6%; and a 600 MW advanced nuclear power plant with an efficiency of 33.4%. No retirement or fuel switching of existing thermal plants was considered in the planning period.

An interest rate of 8% was used during construction for all candidates, while two different discount rates were used: 4% for domestic costs (O&M costs and fuel costs) and 10% for foreign costs (capital costs). An escalation rate of 1% was used for O&M costs, while escalation rates for fuel costs were specified at 2%: for lignite & oil and 3% for natural gas. A foreign cost multiplier of 1.5 was used, and the cost of unsatisfied demand was set at $0.50 US/kW·h.

Fuel requirements for the power sector would be met by extensions to existing mines at Oslomej West and Oslomej North - "Popovjani"; the opening of a new seam (named "Podinski")in Suvodol, and Brod-Gneotino; and imported lignite from Greece using the same conveyor belt as for Brod-Gneotino. In addition, natural gas would be supplied by an existing pipeline with a capacity of 800 million m^3/year and the possibility for increasing capacity to 1200 million m^3/year. About 70 to 80% of the total capacity would be used for electricity generation.

The results of the electricity system expansion scenarios are given in Table10.3, where details about the total system costs, annual plant additions, and peak loads for all three cases are presented. Names of plants committed to come online in the near future are written in normal text, while plants selected by the program to be part of the least cost generating system expansion plan are written with bold letters. As seen in the Table, solutions for all three cases comprised the same set of power plants, but their on-line years were shifted up as electricity demand at the beginning of the study period increases. Depending on the future of the metallurgy facilities in Macedonia (FENIMAK & JUGOHROM), whose operation/shutdown was simulated through the three cases analysed, decisions for new plants construction might have to be taken sooner if these metallurgy facilities remain active.

The decision on the status of the metallurgical industry would also affect the decision on the use of nuclear power for additional capacity. For the case with 6500 GW·h in the year 2001 a decision must be taken within the next 5 years, since a 600 MW nuclear power plant would be needed in the year 2015. Bearing in mind that such decision may not be drawn in the near future, we analysed additional cases where we forced the optimization procedure to postpone the construction of the nuclear plant for two and five years respectively, resulting in three cases: Case 1 - nuclear plant in the year 2015, Case 2 - nuclear plant in the year 2017 and Case 3 - nuclear plant in the year 2020.

Table 10.3. Optimal expansion plans

	Electricity demand in the year 2001 and objective function value					
	6500 GW·h		7000 GW·h		7500 GW·h	
	3,854.9 Million $		4,234.9 Million $		4,602.5 Million $	
Year	Peak (MW)	Additions	Peak (MW)	Additions	Peak (MW)	Additions
2001	1,212.4	HPP Matka 1	1,305.7	HPP Matka 1	1,399.0	HPP Matka 1
2002	1,257.9	HPP Kozjak	1,354.7	HPP Kozjak	1,451.5	HPP Kozjak
2003	1,305.0	-	1,405.5	-	1,505.9	CC 270 MW
2004	1,354.0	HPP B. Most	1,458.2	CC 270 MW	1,562.4	-
2005	1,404.8	HPP Matka 2	1,512.8	HPP Matka 2	1,621.0	HPP Matka 2
2006	1,457.4	CC 270 MW	1,569.6	-	1,681.7	HPP B. Most
2007	1,512.1	-	1,628.4	-	1,744.8	-
2008	1,568.8	-	1,689.5	HPP B. Most	1,810.2	CC 270 MW
2009	1,627.6	-	1,752.9	-	1,878.1	-
2010	1,688.7	-	1,818.6	CC 270 MW	1,948.5	-
2011	1,743.5	-	1,877.7	-	2,011.9	-
2012	1,800.2	CC 270 MW	1,938.7	-	2,077.3	-
2013	1,858.7	-	2,001.7	-	2,144.8	Nuclear AP 600
2014	1,919.1	-	2,066.8	Nuclear AP 600	2,214.5	-
2015	1,981.5	Nuclear AP 600	2,134.0	-	2,286.4	-
2016	2,045.9	-	2,203.3	-	2,360.8	-
2017	2,112.4	-	2,274.9	-	2,437.5	-
2018	2,181.0	-	2,348.9	-	2,516.7	-
2019	2,251.9	-	2,425.2	-	2,598.5	-
2020	2,325.1	-	2,504.0	-	2,682.9	HPP Veles HPP Gradec

Table 10.4. GHG emissions

	Case 1	Case 2	Case 3
Total costs (mill. $)	3,854.9	3,887.9	3,972.9
CO_2 (Mt)	125.3	130.9	137.3
SO_x (kt)	181.1	191.5	200.1
NO_x (kt)	168.4	176.5	188.3

The results from this study show that until 2014 there would be no need for nuclear power in the Macedonian power system. However, delaying the on-line year of a nuclear plant beyond 2015 would increase total system costs because of increased use of natural gas, which would also have additional environmental impacts (Table 10.4). The use of nuclear power plants in Macedonia at the beginning of 21st century would extend the life of lignite coal reserve, and would have the additional environmental advantage of reducing pollution from coal-fired power plants, bringing Macedonia more in line with current world-wide environmental trends.

In order to enhance the DECPAC analysis especially for correct representation of hydro power plants, the VALORAGUA model and an improved model for electricity production planning in a mixed hydrothermal system developed in Macedonia, were used as auxiliary models. The results of these models were supplied as an input data for hydro plants for the overall long-range optimization by the DECPAC model. This report gave special attention to hydrology data and load duration curves. For each month of the year, load duration curves were approximated with fifth order polynomials for DECPAC (WASP) and with staircase functions for VALORAGUA, as was the necessary input data for characterizing hydro plants.

Generally, we found that with the probabilistic simulation of system operation in DECPAC (based on the load duration curves) it is much better to define a different hydro type for each single hydro plant. This would not introduce any practical limitations concerning the numerical procedure, especially for countries with small systems as Macedonia, and would provide a more realistic simulation of the power systems. This representation would also produce the important improvement of allowing all candidate hydro plants to compete between themselves and with thermal plants.

Finally, we would stress that the use of two different discount rates, 4% for domestic and 10% for foreign costs, is very important for the fair treatment of hydro plants. Since the capital costs associated with candidate hydro plants are mainly domestic, the discount rate that is used should be equal to the interest rate given by domestic banks, which no more than 4%. If the discount rate for the domestic costs were 10% (as for the foreign costs), the optimal solution would exclude hydro plants as a very expensive option, or their construction would be considerably postponed.

11. PAKISTAN

INCORPORATION OF ENVIRONMENTAL REGULATIONS IN MEDIUM TO LONG TERM PLANNING FOR ELECTRIC SYSTEM EXPANSION IN PAKISTAN

Due to a very low level of energy and electricity consumption in the country, at present, environmental emissions in Pakistan are relatively low. However, in view of the expected increase in energy and electricity consumption, the environmental problems may become very severe, if appropriate measures are not taken in time. Consequently, the government of Pakistan has developed necessary environmental legislation and environmental standards for all sectors of the economy, including the power sector, and is establishing appropriate mechanisms for enforcement of these standards. This study assesses the impacts of these environmental regulations on future development of the electricity sector in terms of economic cost and environmental burdens. Three alternative cases of electricity sector development have been analysed. The first case assesses the impacts of not enforcing the environmental regulations, while the other two are formulated to find out the impacts of complying with these regulations by varying degree of fuel switching, introduction of control technologies and use of nuclear power.

The scope of this impact assessment encompasses comparison of selected fuel chains for electricity generation in Pakistan, estimation of the external costs associated with the effects on human health due to air emissions from the selected oil and coal power plants, economic comparison of the various options for electricity generation with and without the environmental controls, and ultimately, a comparison of three alternative power system expansions plans in terms of economic costs, environmental burdens and sustainable development. The analysis has been carried out using the set of methodologies developed by IAEA for comparative assessment of alternative sources of electricity generation; in particular the DECADES databases and tools.

The plant-level analysis shows that to comply with the environmental regulations a reduction in SO_2 emissions of 26% is required for furnace oil-based plants and 44% for coal-based plants. Similarly, NO_x emissions from various fossil fuel based plants must be reduced by 40%.

The full fuel chain (fuel extraction, conversion, transportation, electricity generation and waste disposal) comparison shows that the gas chain causes the least environmental burden among the fossil fuel based plants as far as CO_2, NO_x and SO_2 air emissions are concerned. The oil chain is better than the coal chain in terms of CO_2 and comparable in terms of NO_x emissions, but its SO_2 emissions are quite high compared to those from the coal chain due to the high sulphur furnace oil being used in the country. The coal-chain also produces the largest amount of solid and liquid wastes, which contain significant quantities of toxic heavy elements.

To estimate the damages to human health caused by SO_2 and NO_X emissions a simplified approach (Simpacts) developed by the IAEA has been used. For a 600 MW coal-fired plant located near the sea coast it has been estimated that the annual SO2 emissions would cause about 2149 Years of Life Loss (YOLL) for the population around the plant area. For a similar unit based on furnace oil, the damage would be 2443 YOLL, and if the oil-fired plant is located near a demand centre with high population density, the damage could be as high as 4328 YOLL. The major contribution in this health impact is from Chronic Mortality (CM) caused by the sulphate and nitrate formation from these emissions. The monetary values of these health impacts per year from electricity generation for the three power plants considered here vary in the range of 35 to 71 million US dollars. These external costs of electricity generation are in the range of 0.96 to 1.94 cents per kW·h. Excluding any external cost, generation cost of the three plants is around 5.4 cents per kW·h. Thus, if the estimated external costs are included, the generation costs would increase by 15% to 27%.

Taking 1996-97 as the base year for the planning period, the study has used the DECPAC model to derive the least-cost power system configuration in the 25 years period under three alternative cases of power system expansion. The future growth in electricity demand assumed in the three cases is common (7-8% per annum). Similarly, the maximum capacity that can be built using domestic coal, imported gas and hydro are common in all the cases. The main differences between the there cases are: Case I assumes that air emissions from existing as well as future power plants will remain uncontrolled. Cases II and III both assume fuel switching and installation of control technologies on the fossil fuel based plants to comply with regulated air emissions limits. Case III also permits building nuclear power capacity at a moderate rate, while Case II assumes no addition of new nuclear power plants.

As shown in Table 11.1, Pakistan would need to build about 72,000 MW of additional capacity in the next 25 years. Hydro and natural gas could contribute up to 16% and 8%, respectively, to this total capacity. The remaining 76% (i.e. 54,000 MW) capacity would have to be based on other available options. The simulation results of Case I show that indigenous coal could contribute 15,000 MW and the remaining 33,000 MW would be based on imported oil. However, I Case I (unconstrained emissions) this configuration of capacity expansion would result in excessively high emissions; a 12-fold increase in SO_2 and NO_x and about a 9-fold increase in CO_2 compared to the base year. If the environmental regulations are to be complied with (Case II), the oil-based capacity would have to be switched from high sulphur furnace oil to low sulphur furnace oil and FGD (flue gas desulphurization) technology would have to be used for coal plants. These measures would reduce environmental emissions to permissible levels, though the total cost will be higher compared to Case I. Alternatively, if addition of nuclear power plants were to be considered (Case III), these would replace fossil fuel based capacity by 16,135 MW; replacing 1,600 MW of coal-based and 14,535 MW of oil based plant. In this case, there would be a significant additional reduction in air emissions from the power sector, especially CO_2 emissions.

In terms of economic costs, total electricity generation cost in the study period Case I would be 205 billion US dollars in 1997 prices. Compliance with SO_2 and NO_x control guidelines in Cases II and III would increase this cost of electricity generation by 8% and 6.6%, respectively. The cost break down shows that although the cumulative investment requirements would be higher in case III (i.e. 104 billion US dollars), its low operating cost would reduce the total cost of electricity generation. Hence, the use of nuclear power technology in the power system development would have the benefit of a greater reduction in air pollution without any additional economic burden.

This study also evaluated the sustainability of these plans using four indicators i.e. primary energy (PE) consumption per unit of electricity generation; air emissions of SO_2, $NO_{x;}$ and CO_2 per unit of electricity generation. The future trend of these indicators shows that in all the cases there would be an increase in the air emission intensity over the period but this increase is lowest in Case III; about 50% less in the 25th and final year for SO_2. Similarly, there would be is a declining trend in PE intensity for all cases but this decline is higher in Case III. Therefore, from a sustainability view point CASE III would still be more desirable.

Table 11.1. Future mix of installed electricity generation capacity in three cases and the associated environmental burdens

	1997	2021		
		CASE I	CASE II	CASE III
Peak Demand (MW)	9,883	72,079		
Installed Capacity (MW)	14,009	85,746	85,721	85,786
Coal-Steam without FGD	162	15,150	150	150
Coal-Steam with FGD	0	0	15,400	13,800
High Sulphur FO-Steam	4,599	37,887	0	0
Low Sulphur FO-Steam	0	0	36,687	21,687
Gas-Steam	1,212	0	0	0
Gas-Combined Cycle	2,662	10,752	10,752	10,752
HSD-Comb. Turbine	420	4,805	5,580	6,045
Nuclear	70	650	650	16,850
Hydro	4,884	16,502	16,502	16,502
Air Emissions (Million Tonnes)				
CO_2	27	247	249	156
SO_2	0.23	3.15	1.20	0.65
NO_x	0.08	0.95	0.56	0.34

The current study revealed that the enforcement of environmental regulations in the country will have considerable impact on the power system expansion in terms of investment requirements, operating costs, external costs of electricity generation and environmental burdens. The comparative analysis of the alternative expansion plans shows that the magnitude of these impacts very much depends on the strategies to comply with them. Use of nuclear power to the maximum feasible level would be part of the least cost strategy for future expansion of electricity sector in a sustainable manner.

12. PERU

DECADES CASE STUDY FOR PERU

This report summarizes results of a study carried out, using the DECADES computer tools, to analyse long term development options of the Peruvian electric power system during the period 2000 to 2025.

The study considered energy resources and technologies for the entire Electricity Generation Interconnected System (EGIS) of Peru to develop a least-cost generation system expansion plan that is consistent with prevailing government policies, macroeconomic conditions and resource availability in the country. The analysis also provides an estimate of the level of air pollutant emissions associated with power plants and auxiliary activities.

Two load forecasts ("medium" and "high") were used in this study to represent the range of possible load growth in the future. Figure12.1 shows the Peak Load and Installed Capacity of the EGIS in Peru for the period 2000 to 2025. As can be seen, currently installed capacity is would be sufficient to meet expect electricity demand over the next four years. However, it is expected that a significant amount of new capacity would have to be added to the system beginning in 2005.

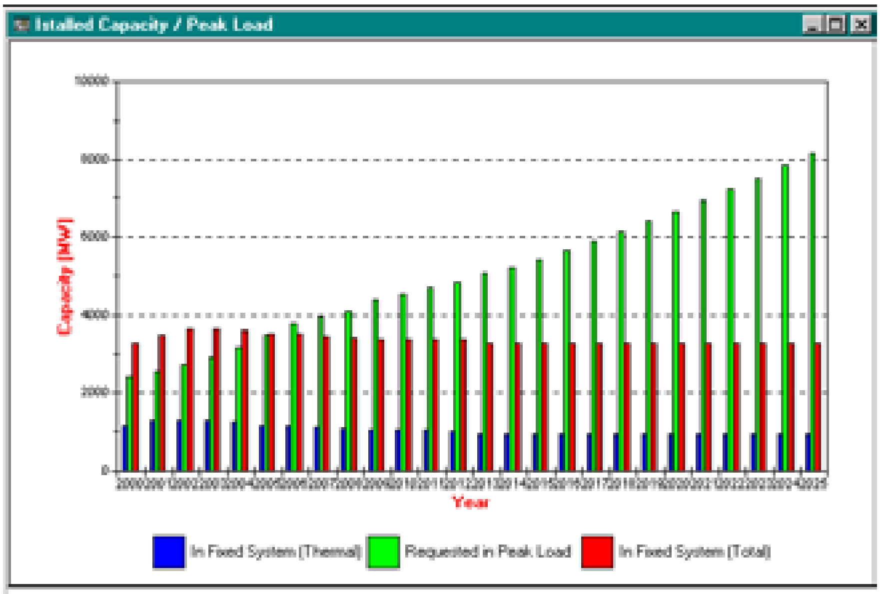


Figure 12.1. Installed capacity and peak load for national electrical interconnected system.

The annual peak load and associated least-cost expansion plan obtained for the medium growth scenario are presented in Table 12.1 The results show that natural gas-fired units would be very favourable for future generating system expansion in Peru. The total construction of new capacity over the study period comprised 4050 MW of thermal, 600 MW of nuclear and 234 MW of Hydro.

The air pollution emissions of the development plan for the medium scenario are illustrated in Figures 12.2 and 12.3. As shown, the increasing dependence on fossil-fired power plants would greatly increase the level of environmental burdens from the electricity system, with CO_2 being the most important from the point of view of global environmental concerns.

In both studied scenarios (i.e., medium and high growth) the results show that nuclear option would be feasible for Peru in the context of rational use of energy resources.

Table 12.1. Least-cost expansion plan for medium growth scenario

YEAR	PEAK LOAD (MW)	UNIT ADDITIONS THERMAL	HYDRO	NUCLEAR
2000	2399			
2001	2570			
2002	2761			
2003	2904	1TGCA(150MW)		
2004	3165	2TGCA(300MW)		
2005	3357	1TGCA(150MW)	1J104(104MW) 1YUNC(130MW)	
2006	3625	1CC45(450MW)		
2007	3767	1CC45(450MW) 1TGCA(150MW)		
2008	3955			
2009	4074	1CC45(450MW)		
2010	4174			
2011	4295			
2012	4415			
2013	4543	2TGCA(300MW)		
2014	4669			
2015	4781	1TGCA(150MW)		
2016	4918			1 NU60 (600 MW)
2017	5060			
2018	5206			
2019	5357	1TGCA(300MW)		
2020	5512	1TGCA(150MW) 1TGCA(150MW)		
2021	5671	1TD15(150MW)		
2022	5835	1TGCA(150 MW)		
2023	6004	1CC45(450MW)		
2024	6178			
2025	6356	1TD15(150MW)		
TOTAL	115551	4050 MW	234 MW	600 MW

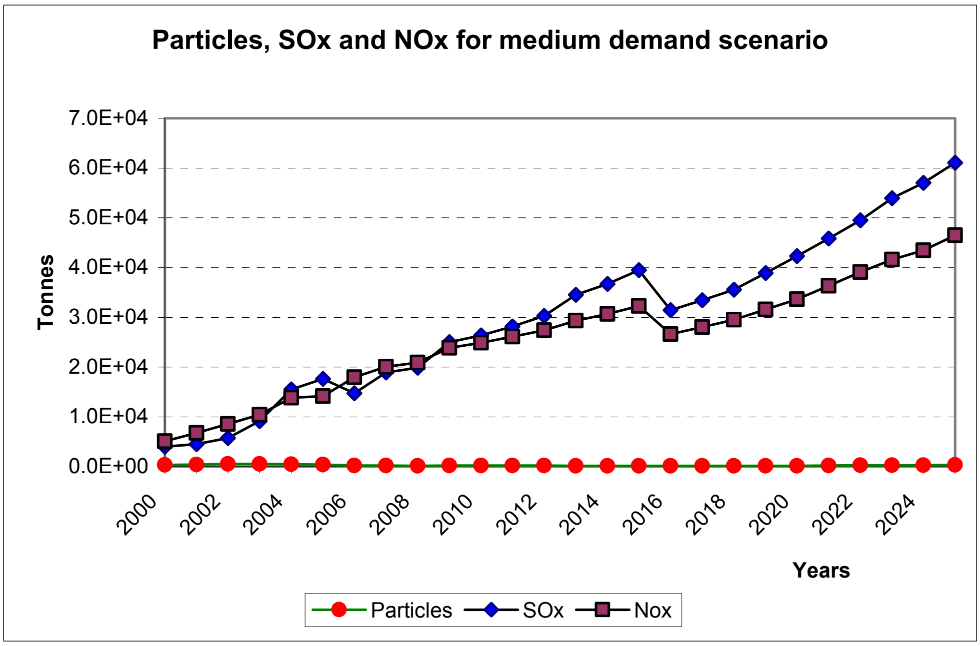


Figure 12.2. Emissions of particles, SO_x and NO_x for medium scenario.

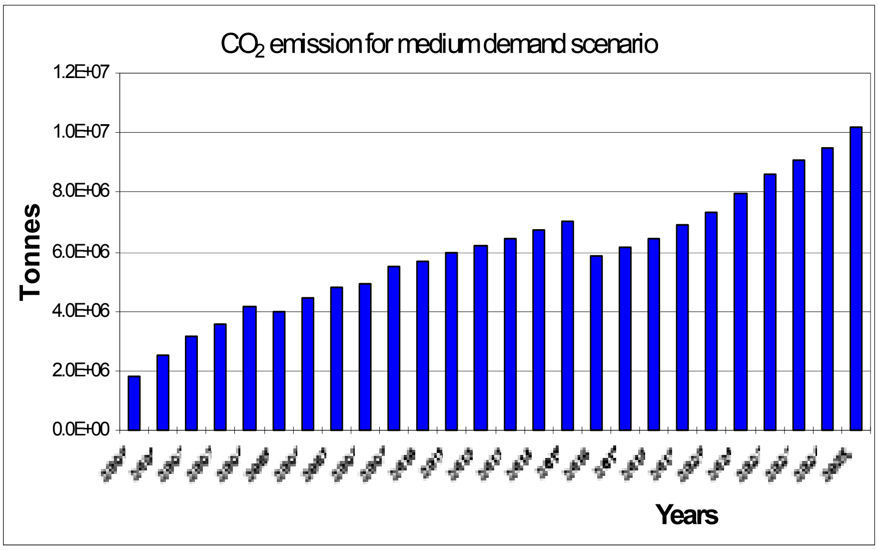


Figure 12.3. Emission of CO_2 for Medium Scenario.

13. PHILIPPINES

ESTABLISHMENT OF A COUNTRY SPECIFIC DATABASE FOR THE COMPARATIVE ASSESSMENT OF ELECTRICITY PLANTS GENERATING IN THE PHILIPPINES

The electricity system planning process requires that an energy programme be continuously re-assessed against the country's economic aspirations and the changing realities of the environment. In previous years, electricity planning in the Philippines placed substantial emphasis on ensuring energy availability in view of the worldwide oil crisis in the nineteen seventies and a national electricity shortage in the nineteen eighties. Recently, a more comprehensive approach is being pursued that gives more balanced emphasis to a number of critical energy sector objectives. Among these are: ensuring sustainability of energy supply; and enhancing the integration of energy and environmental policies; and program implementation in the context of global and national initiatives to mitigate impacts of climate change and local pollution. In addition, the Philippine energy sector is in transition as the government is gradually restructuring the industry through energy liberalization and deregulation. The program of deregulation is expected to hasten economic development and industrialization, which supports the national goal for the "development and utilization of socially and environmentally compatible energy infrastructures to ensure sustainable and reliable economic supply of energy with greater emphasis on private sector participation" as mandated by Republic Act No. 7638.

Based on this policy thrust, the latest update to the Philippine Energy Plan provided insights into the requirements of the energy industry over the next ten years. According to this Plan, the country's economic and demographic growth patterns would continue to be major factors influencing the growth in energy demand. Gross domestic product (GDP) would grow at an annual rate of 5.1% during the period 2000 to 2004 and at 6.2% for the years 2005 to 2009. Growth in energy demand would accelerate from an annual rate of 5.3% in 2000 to 2004 to 7.0% for the period 2005 to 2009. Meanwhile, the population would grow from the current level of 76.3 million to 90.3 million in 2009, an average annual growth of 2.1%. Electricity would grow at a steady rate of 8.9% over the next ten years. For purposes of this study, this growth rate was assumed to be constant up to the year 2020.

With regards to environmental management, key policies and programs are being provided to ensure an integrated energy-environment approach in the context of global and national development thrust. Several laws have been enacted or issued to address this policy concern; the most important of which is Republic Act No. 8749 or the Philippine Clean Air Act of 1999. The Department of Environment and Natural Resources (DENR) has issued regulations governing standards on air quality and pollution and toxic wastes. With these constraints, it is expected that the development and utilization of energy resources will be critically guided, not solely by economics, but also by principles of cultural and ecological sensitivity.

To provide additional inputs to policy makers and national decision makers for the implementation of strategies and programs for the achievement of energy sector policies, a national case study was conducted. This study was also pursued as one of the activities of the Nuclear Power Steering Committee, Subcommittee on Research and Development for Nuclear Safety. This report presents the results of this case study. The study was conducted with the following specific objectives:

- To develop a country specific data base on energy sources, facilities and technologies;
- To identify feasible national electricity generating options and electric power system expansion alternatives for the period 2000-2020, and to conduct a comparative assessment of these options based on economic and environmental considerations, and
- To determine the possible role of nuclear power in the country's future electric energy mix.

At present, electric energy is produced from four main energy sources: oil, hydro, coal and geothermal. Since the 1970's, oil–fired power plants have played a dominant role in meeting the country's electricity requirements. Before the end of the 20th century, oil-based plants composed about 50 per cent of the total installed capacity, with all of the fuel imported. The next largest source of electricity is from hydroelectric plants (about 19%), with geothermal and coal supplying the balance.

According to the latest Philippine Energy Plan Update, the country's demand for electricity will grow at an annual rate of 8.6 per cent from 43,780 GW·h in 1999 to 99,714 GW·h in 2009. To meet this long term demand for electricity, a total of 9,875 MW of new generating capacity would have to be installed in the next ten years.

For the longer term, the government is expected to pursue the full development of local energy sources such as hydropower, geothermal, coal, natural gas, and other new and renewable energy sources. However, there will still be a major need for imported oil and coal which will likely supply unidentified energy sources beyond 2010. In the case of nuclear power, the government has not firmed up definite plans for any construction of nuclear power plants after 2010. However, the long term energy development plan still includes the operation of at least two nuclear power plants by the year 2020, and this long term program has not been revised in the latest updates.

Continuing electricity demand growth combined with constraints on the system pose a challenge to those responsible for developing and deploying technologies. Existing technologies are being improved but new technologies have yet to prove their full market potential. One of the main constraints on decision makers is the limited number of new generating technology options available. Given the long lead-time of new technologies, only those currently in the research, development or demonstration phases are likely to be commercially available in a significant scale by 2020.

Of the 9.875 MW of new generating capacity that is needed to be installed in the next ten years, 5,255 MW are committed projects, i.e., power plants that are under construction or have been contracted out to private entities for development. The balance of 4,620 MW represents the uncommitted capacity requirement expected to be provided under a liberalized power market. These indicative capacity requirements are expected to be filled up by 1,600 MW of base-load capacity, 1,170 MW of mid-range and 1,850 MW of peaking power plants.

Locally available energy sources - hydroelectric, geothermal, natural gas and coal – are expected to be fully utilized in satisfying basic national policies, particularly those aimed at ensuring sustainability of energy supply.

As modelled, the composition of the installed electric power mix by year 2000 would be as follows: oil-fired plants, 5,194 MW (42%), coal plants, 3500 MW (28%), geothermal, 1937 MW (15%) and hydroelectric 1933MW (15%). There would be a net addition of 3,216 MW installed capacity over the next ten years, most of which (2,400 MW) would be natural gas and to a lesser extent (900 MW) hydroelectric plants. Oil-fired capacity would be reduced by about 700 MW mainly due to the retirement of old generating plants.

For the system expansion scenarios analysed under this study, fossil-fired, hydroelectric and geothermal power plants were considered as candidates. The two main scenarios that were analyzed, included:

- Non-nuclear option: No nuclear power plants built during the study period.
- Nuclear power option: Nuclear plants to operate by 2019.

For both alternatives, six types of candidate thermal plants and two types of hydroelectric plants were considered. There were seven thermal expansion alternatives from five fuel groups, namely: gas-turbine, combined cycle diesel, two types of coal fired power plants, one natural gas, one geothermal and one nuclear plant. In addition, four hydroelectric candidates were included. Except for the nuclear plant, all candidates were considered for both of the identified scenarios

The optimum solution derived for both the nuclear and the non-nuclear alternatives indicated that oil-fired and coal-fired generation would dominate the generation mix by the year 2020. The contribution of nuclear power plants by the year 2019 would barely decrease the contribution of the oil and coal plants. Coal plants would increase their share of total capacity from 27% to 36%, while oil's share would fall from 40% to 30%. Gas-fired generation would start in 2002 and reach 16% of total generation by 2020. Meanwhile, geothermal power, when fully developed, would account for about 5.6%. The generating mix as modelled is shown in Figure 13.1.

There is definitely room for nuclear power by the year 2020. In the short term however, the government does not consider nuclear power as needed given the priority assigned to the full development of locally available natural gas, hydroelectric and geothermal resources. Despite this development of indigenous resources, there will be an ever-increasing need for coal and oil-fired power plants in the next decade, with coal overtaking oil by 2019. Even the introduction of nuclear plants would not significantly affect this dependence on coal.

Considering the high ash content and sulphur emission of coal-fired power plants, there is an ever-increasing need for the use of new technologies to reduce the health impacts of coal combustion. Since existing coal-fired power plants in the country have not been equipped with FGD, the health and environmental effects of a typical coal plant were assessed and compared against two other options, namely: a coal plant using FGD with a 90% removal efficiency and a combined cycle plant using oil. Using the IAEA's simplified approach for estimating external costs associated with electricity generation, called Simpacts, it was estimated that a 300 MW coal plant located in a medium urban coastal area could cause damages of some 3550 years of life lost (YOLL) due to SO_2 emissions as compared to 7583 YOLL for a similar combined cycle plant. The total damage cost per kWh of operating these plants over 30 years ranges from $43 million for the coal plant with FGD to as much as $720 million for the combined cycle plant. Using the Decision Aiding Module of Simpacts, and using emissions, annualized costs and damage costs as selection criteria, a multi-criteria analysis indicates that the coal fired power plant with FGD would be the best option and should be seriously considered in the construction of future plants

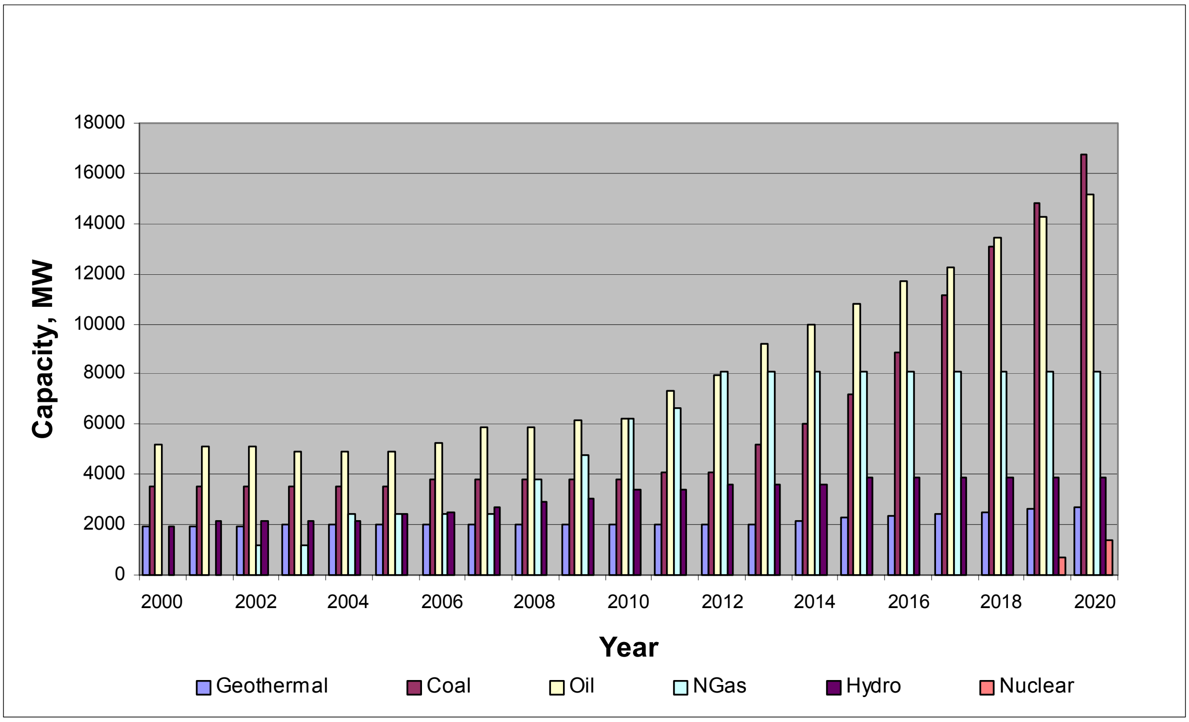


Figure 13.1. Fixed system plus optimum solution.

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14. ROMANIA

ESTABLISHMENT OF THE NUCLEAR POWER PLANT ROLE IN THE GREENHOUSE GASES EMISSION REDUCTION IN ROMANIA

14.1. Introduction

The transition to a market-based economy in Romania led to a 5.6% annual decrease in electricity consumption, from 71.4 TW·h, in 1989, to 39.9 TW·h in 1999. However, in the next decade's electricity demand is expected to increase by at least 1.3% per year. In order to meet the future electricity needs of the country in a sustainable manner, the electricity sector must adopt adequate restructuring, modernization and development strategies.

The aim of the present research is to explore the potential role of nuclear power in the sustainable energy development of Romania, with particular attention given to assessing various options for mitigating greenhouse gas (GHG) emissions. The DECADES Tools were used in this research to evaluate the economic and environmental consequences of alternative electricity system development options.

Following the country's application for membership in the European Union (EU) and the signing of the European Energy Charter, Romania is committed to harmonizing its legislation with EU laws and regulations. As the EU explores CO_2 taxes as a possible policy instrument to reduce GHG emissions, the current study assesses the competitiveness of nuclear power, and other GHG mitigation options, under levels of CO_2 taxation ranging from 2 to 22 \$/tCO_2.

14.2. Study Assumptions

An updated forecast of final electricity demand for a medium economic development scenario is presented in Table14.1.The projections assume a large improvement in energy efficiency between 1995 and the year 2020, both in absolute terms and relative to past achievements. Under this scenario, electricity demand is expected to continue growing at 1.8% per year.

As candidates for electricity system expansion, the study considered:

- -*/- Rehabilitation of existing units;
- 330 MW fuelled on lignite with and without FGD and low NO_x burners;
- 200 MW fuelled on domestic hard coal or imported hard coal, both with and without FGD and NO_x reduction devices;
- 200 MW fuelled on heavy fuel oil with sulphur content below 1% provided with low NO_x burners;
- Completion of new units under construction:
- 4   700 MW in Cernavoda NPP;
- 1   330 MW PC fuelled on lignite provided with low NO_x burners;
- 870 MW in hydro power plants;
- addition of new units:
- 100 MW and 250 MW combined cycle on natural gas provided with steam injection;
- 250 MW PC on imported hard coal provided with FGD and NO_x reduction devices;
- 250 MW - FBC on domestic lignite provided with FGD and low NO_x burners;
- 700 MW nuclear units with CANDU reactors.

Table 14.1. Forecast of Final Electricity Demand for Medium Alternative

	MU	1997	2000	2010	2020
Final electricity demand	TW·h	44.7	39.8	51.3	60.0
Electricity per capita	kW·h/inh	1983	1779	2367	2857
Electricity intensity of GDP	kW·h/1000$ppc	498	487	418	326
Electricity penetration to final energy demand	%	11.07	11.14	11.78	12.57
Annual peak load	MW	8742	7923	10547	12433
Load factor	%	67.27	65.03	62.98	62.05

14.3. Screening Analysis of Electricity System Expansion Candidates

Due to the large number of candidates selected for electric generation system expansion in Romania, a preliminary screening analysis was carried out to determine their economic merits for system expansion. The economic rank ordering of these candidates was based on the levelized production cost for the specific capacity factor for each plant or generating unit. Table 14.2 shows the ranking order for all candidate fossil-fired and nuclear power plants. The screening analysis indicates that, in the absence of CO_2 taxes, the most economic option for capacity expansion is to complete construction of unit 2 at the Cernavoda NPP, while the least economic option in this study is to construct a new NPP.

14.4. Evaluation of NPP Role in Reduction of GHG Emissions

In the absence of a CO_2 tax, results of the study indicate that the least-cost generation system expansion for Romania includes:

Completion of Unit 2 of the Cernavoda NPP, in 2004, for all scenarios considered; and

Completion of the Unit 3 of the Cernavoda NPP, after 2010, only with constraints imposed on natural gas imports and with high escalation of fuel prices.

Completion of Units 4 and 5 of the Cernavoda NPP are not part of the least cost solution in any analysed scenarios.

The scenarios with CO_2 taxes present the following features:

With a CO_2 tax of 2 $/t$CO_2$, the introduction of Unit 3 of the Cernavoda NPP is part of the optimal solution for all scenarios and the share of nuclear power in total installed capacity reaches 8% in 2020.

With a CO_2 tax of 10 $/t$CO_2$, Unit 3 of the Cernavoda NPP is introduced before 2015 for the scenarios with low fuel price escalation. In addition, for the scenario with high escalation of fuel prices the completion of Units 4 and 5 of the Cernavoda NPP are part of the optimal solution, and the nuclear share reaches 16% of installed capacity.

With a CO_2 tax of 22 \$/tCO_2, the completion of all units of Cernavoda NPP and construction of a new NPP are part of the least-cost solution, and the share of nuclear power reaches 23% of the total installed capacity in 2020.

It is worth noting that the CO_2 taxes do not promote increased construction of hydro projects. Rather, tax rates higher than 10 \$/tCO_2 result in some scenarios in the replacement of TPPs with NPPs.

As for the contribution of nuclear power to GHG emission reductions, the analysis concludes that the lowest level of CO_2 emissions is tied to the highest share of NPP and the highest CO_2 taxes. Compared with the no-tax scenario, increasing the nuclear power's share to 19% of installed capacity would reduce CO_2 emissions by 35% in 2010 and by 45% in 2020.

Table 14.2. Ranking Order of Electricity System Expansion Candidates

Ranking Order	Unit Type and Name	$/kWe-a
1	N2 – Under construction	200.08
2	*RBRT - Rehabilitated	222.24
3	CC25 - New Unit	229.08
4	*TA8 – Under construction	237.16
5	*CC00 - New Unit	239.27
6	*RMDF - Rehabilitated	252.35
7	*RT3F - Rehabilitated	253.38
8	*RI3F - Rehabilitated	256.57
9	*RMIF - Rehabilitated	261.97
10	N3 – Under construction	301.28
11	N4 – Under construction	321.12
12	N5 – Under construction	325.25
13	HC30 - New Unit	344.56
14	LG20 - New Unit	357.43
15	NNUC - New Unit	370.97

** Considered as IPP's investments.*

14.5. Appraisal of the Sustainability of Electricity System Development Scenarios

To appraise the feasibility, viability and sustainability of electricity system development scenarios, sustainable energy development indicators were devised based on the framework and methodologies for indicators of sustainable development elaborated by the United Nations. The indicators presented in Table14.3 were calculated based on results produced by the DECADES Tools. They have been used to evaluate the sustainability of the expansion scenarios on a number of criteria.

In the short and medium term (up to 2010) the projected electricity system developments appear feasible, efficient, secure and viable options; their environmental impact could be controlled if the appropriate measures were taken. But for the long term, the projected scenarios appear unsustainable, particularly due to limitations in maintaining the security of energy supplies.

The projected scenarios, viewed through these indicators, present attractive options in many regards for satisfying the needs of sustainable development:

Meeting the energy service requirement;

Assigning a greater role to the rational use of energy;

- Operating based on the cost-effectively, within the market mechanisms;
- Suggesting that the rise of electricity costs to final-consumers will not be disruptive; and
- Being technically feasible, not only with regard to enhanced energy economy and efficiency.
- In addition, applying indicators to these projections aids in the early identification of risks, including:
- Increasing energy import dependence;
- No penetration of the new renewable sources for electricity generation;
- Slow and low penetration of the hydro energy;
- Market imperfections of the market mechanism and exclusion of externalities from price formation;
- Constrained financing possibilities for new capacity or for environmental control techniques;
- Major uncertainties for fossil fuel use resulting from the perceived long-term risk of climate change; and
- Uncertainty about the rate of nuclear power growth, which would seem to depend on the possibilities for financing.

14.6. Conclusions

The analysis has shown that the development of gas-fired combined cycle power plants is the least cost solution for expansion of the electric system in Romania. This option also has benefits from the point of view of GHG emissions, but is only viable if natural gas import sources can be diversified. .

Scenarios positing both increasing fuel prices (consonant with the International Energy IAEA's fuel prices prognoses) and the introduction of CO_2 taxes, favour the increased development of the nuclear power in Romania.

Based on the findings of this study, it is recommended that decision-makers charting sustainable strategies of energy supply and use should give consideration to the following elements:

- Rational use of energy;
- Reduction of the relative importance of fossil fuels in favor of non-CO_2-emitting sources, proved their impact on the environment is acceptable;
- The development of pollution abatement technologies;
- A continued assessment of the environmental impacts of nuclear energy;
- Modernization of the lignite mines to reduce the production costs;
- Review of hydro potential;
- New financial solutions to promote new energy sources, hydro and nuclear energy.

Table 14.3. Sustainable Development Indicators Relevant for Electricity System

Crt. Nr.	Specification	Type of indicator	Criteria
1.	Yearly consumption of final electricity	Driving force	Capacity to meet anticipated demand
2.	Yearly consumption of final electricity per capita	Driving force	Capacity to meet anticipated demand
3.	Proven fossil fuel energy reserves	State	Compatibility with energy reserves, resources
4.	Lifetime of proven energy reserves	Driving force	Security of energy supply
5.	Share of fossil fuel import for electricity production	State	Security of energy supply
6.	Average efficiency for electricity production from fossil fuel energy resources	Driving force	Progress in energy efficiency
7.	Yearly consumption of final electricity per GDP	Driving force	Progress in energy efficiency
8.	Cumulated objective function	State	Cost effectiveness of resources allocation
9.	Electricity levelized costs for study period	Driving force	Rising electricity supply costs
10.	Yearly total emissions of greenhouse gasses (CO_2, CH_4, N_2O) expressed in equivalent CO_2 in electricity system	Driving force	Environmental and climatic hazards
11.	Yearly total emissions of sulphur oxides in electricity system	Driving force	Environmental and climatic hazards
12.	Yearly total emissions of nitrogen oxides in electricity system	Driving force	Environmental and climatic hazards
13.	Yearly total emissions of particulates in electricity system	Driving force	Environmental and climatic hazards
14.	Generation of solid waste in electricity system	Driving force	Environmental and climatic hazards

15. RUSSIAN FEDERATION

ECONOMIC ASSESSMENT AND ENVIRONMENTAL CONSEQUENCES OF DIFFERENT ENERGY OPTIONS TO MEET ELECTRICITY DEMAND IN THE NORTHWEST REGION OF THE RUSSIAN FEDERATION

The last years have seen a dramatic change in electricity production and in the fuel mix in Russian Federation. From the beginning of the 1990s, a sharp drop in industrial production has resulted in declining demand for electricity. In fact, electricity production dropped nearly 23% between 1991 and 1999. But at present time there are tendencies towards recovery from the economic crisis and real perspectives that this situation will begin to change in the near future. Since the end of 1998, some economic growth is being observed in Russian Federation.

One of the main features of current electricity production in Russian Federation is a high share of natural gas, which accounts for 41% of total electricity production and 61% of generating sector fossil fuel consumption. Up to now nuclear power (NP) retains its position as one of the major energy sources in the Russian Federation power system. In 1999, NP had a 15% share of electricity power production in the whole of Russian Federation (i.e., the Unified Power System - UPS). In some power systems in Russian Federation NP has an even greater share in the regional generation fuel mix, such as the Central Power Pool (where NP has a 22% share) and the North-West Power Pool (40%).

The goal of the current study was to carry out a comparative assessment of energy mixes to meet electricity demand in the Northwest region of the Russian Federation and to consider the potential role of nuclear power in the region in the long-term perspective. The North-West region was chosen because it is expected to be faced soon with electricity production cuts of more than 25% due to the expiration of the design lifetime (30 years) and possible shutdown of two units at the Kola NPP (VVER-440 Reactors, 1st generation) and two units (RBMK, 1st generation) at the Leningrad NPP. Till now nuclear power generation has met a steady and major portion of the region’s electricity demand. Could it maintain this position? The study was performed with the use of methodologies developed by IAEA for comparative assessment of different energy sources for electricity generation, namely the DECADES Tools.

Northwest electricity demand in 1997 was 58.8 mln MW·h with a maximum electricity load of about 9.5 million kW. The regional power system had an installed capacity of 14.8 million kW by the end of 1997. However, an essential part of this existing capacity is reaching the end of its service life and will be retired in the near future. Five NPP units with a total capacity of 3880 MWe could be decommissioned prior to the 2010. If the present schedule of unit retirements is carried out, only 50% of the existing generating capacity in the region will remain in operation by the year 2010, with the total installed capacity of existing plants declining from roughly 15 GW to 7 GW.

The study considers a set of possible energy demand scenarios for the Northwest region, reflecting possible paths of economic development. The analysis performed shows that, in the near future, existing capacity will be sufficient to meet the projected electricity demand. However, depending on future levels of electricity demand and export commitment, between 12 GW and 16 GW of new capacity will need to be installed by 2010 to provide a reliable power supply for the region.

Low cost domestic coal and gas are now being transported from the main national deposits to fuel the Northwest power system. A review of costs shows that coal is far more expensive than gas due to the high costs of extraction and transportation (tariffs). Moreover, in recent years natural gas prices, unlike the prices for coal and fuel oil, have been regulated by the State and have been maintained at a rather low level. In the future, it is assumed that the domestic gas prices will increase. The projection of cost escalation factors is the key driving parameter for the power system development.

A number of electricity system expansion scenarios were developed for different scenarios of electricity demand in the region in order to evaluate possible regional power system development paths. The outlook for nuclear power in the region was analysed on the basis of the expansion scenarios developed. The analysis shows that the factors having a crucial effect on the future of NP includes: growth in energy demand and export commitments, fuel availability, and fuel prices.

Under the scenario of high demand for electricity, which corresponds to favourable economic development, NP is fairly competitive in the long term and should retain its role as one of the major electricity generation sources in Russian Federation. In this scenario, the projected escalation of fossil fuel prices also has a positive effect on the competitiveness of NP. In the case of low electricity demand, NP loses its leading role in the regional power mix. The capacity additions required under the various strategies of regional power system expansion is provided in Table 15.1.

Table 15.1. capacity additions

	High electricity demand 2010			Low electricity demand 2010		
	Scenario 1	Scenario 2	Scenario 3	Scenario 1	Scenario 2	Scenario 3
Electricity power demand, thousand GWH	79	79.4	83.2	70.3	64	67
Required installed capacity, thousand MW	15.7	15.6	16.3	13.1	12	12.5
Capacity additions, MW from which:	6500	6400	7150	3950	2750	3350
Combined cycle (gas)	1400	1750	1750	1050	350	350
Condensing plants (gas)	1200	900	1500	1200	1800	2400
gas turbine (gas)	600	450	600	600	600	600
Condensing plants (coal)	-	-	-	-	-	-
nuclear plants	3300	3300	3300	1100	-	-

Under all scenarios, gas-fired plants are the most efficient power sources for developing the regional power system. The share of these generating facilities in the capacity additions is about 50%. Coal fired plants are not competitive over the study period because of their costs. The share of nuclear power plants in capacity additions ranges from about 50% to 28% for different scenarios. For the scenarios of low electricity demand the optimal development plans do not include nuclear options.

The resulting level and structure of installed capacity for the different scenarios considered are represented in Fig 15.1–15.2. The results reveal that natural gas will enjoy the major share in all electricity consumption options. In the case of high electricity demand, NP will keep its role as a major electricity generating option in the regional power system, with a share of about 33% in 2010, as compared with 38.2% in 1997. The level of installed capacity will remain stable for all other fuel types, with natural gas capturing the growth in fuel mix requirements. Under the low electricity demand scenarios, the share of nuclear capacity will decline to 15% in 2010. Gas will dominate in the regional energy mix under all scenarios, because of its comparatively low price in comparison with other types of fuel.

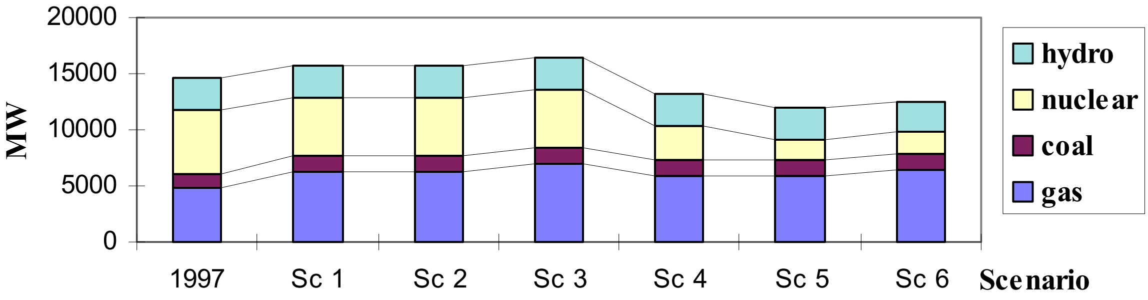

Figure 15.1. Projected regional capacity mix by 2010.

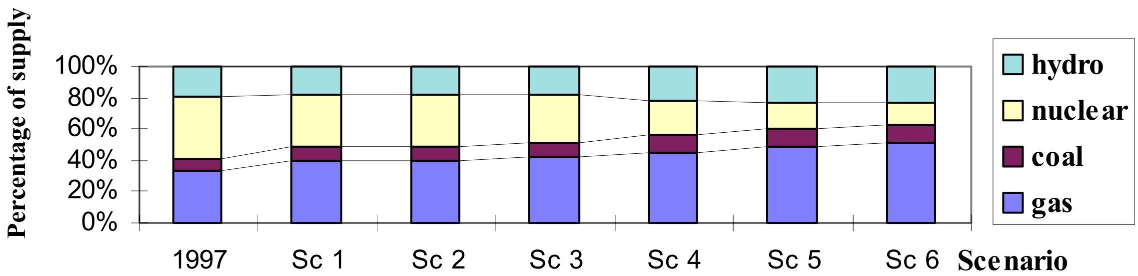

Figure 15.2. Regional energy mix 2010 for 6 scenarios of electricity demand.

The economic growth projections considered in this study all show an increase in fossil fuel consumption and a growing gas dominance up to half of all regional energy use, and some 25% more gas use than today. All six electricity scenarios assume some nuclear power contribution over the study period, ranging from 32% to 15%. The long-term economic viability of nuclear power strongly depends primarily on economics (demand growth, fuel prices, etc.) and environmental considerations. The study confirms that under current economic conditions, cost escalation factors are the key driving parameter for system development. Since fuel costs account for some 50 - 80% of the life-cycle costs for fossil-fired plants, the increasing prices of fossil energy will enhance the competitiveness of nuclear power.

The DECADES Computer Tools were used in the course of the project for analysing various aspects of the long term role of nuclear power in the North-West region of the Russian Federation. The results of this study are in accord with the results of other studies performed by various state organizations. Thus, the IAEA's planning methodology and tools can be used as powerful tools for analysis of regional power system development in Russian Federation.

16. SLOVAKIA

THE USE OF DECADES FOR THE POLICY MAKING PROCESS TO COMPLY WITH ENVIRONMENTAL REQUIREMENTS IN THE ELECTRICITY GENERATING SECTOR IN SLOVAKIA

This Summary describes the results obtained under a Research Contract titled "The Use of DECADES for the Policy Making Process to Comply with Environmental Requirements in the Electricity Generating Sector in the Slovak Republic" that was conducted as part of the IAEA's Co-ordinated Research Programme (CRP) on "Case Studies on Comparing Sustainable Energy Mixes for Electricity Generation."

16.1. Scope of Work

Under this research project, the IAEA's DECADES Tools were used to conduct a comparative assessment of different energy chains for electricity generation in Slovakia. Initial activities focused on updating the Country Specific Database for Slovakia, analysing typical energy chains for electricity supply in the country, and comparing alternative power plants and energy chains. Subsequent research focused on analysing the following system-level issues:

Determining the optimum combination of candidates for electricity system expansion (nuclear power, combined cycles and fluidised bed combustion of domestic lignite), and performing sensitivity analysis with respect to nuclear power investment costs, level of carbon tax and escalation of lignite prices;

Evaluating the impact that retiring existing nuclear units would have on the national level of GHG emissions during the Kyoto Protocol commitment period of 2008–2012;

Evaluating the impact that Independent Power Producers (IPP) might have on capacity expansion, electricity generation and GHG emissions; and

Establishing indicators for sustainable energy development that are consistent with Agenda 21 and using the IAEA's Decision Aiding Module (DAM) to rank the various expansion scenarios based on selected indicators (criteria).

Following decisions taken by the Slovak government to retire existing nuclear units (i.e., 1 440 MWe in 2006 and 1 440 MWe in 2008) and to suspend funding for additional nuclear units at Mochovce, a final stage of research was conducted under this project to:

- Analyze the impact that nuclear energy has had in reducing energy related CO_2 emissions in Slovakia;
- Analyze the potential for obtaining CO_2 Emission Reductions Units (ERUs) by finalizing construction of two nuclear units (2 440 MWe). Since construction of these units was stopped for lack of investment, the analysis is intended to flesh out how emission trading could help provide finance for such units;
- Analyze the potential for Joint Implementation projects in the industrial sector; and
- Use the ECOSENSE model to determine the external costs of SO_2 and NO_x emissions and compare these values with existing emission charges in Slovakia.

16.2. Results Obtained

Sensitivity analyses were carried out using different criteria to quantify the impact of NPP retirements on the level of emissions. The first scenario assumes that retired NPP units will be replaced by newly constructed combined cycle power plants (without cogeneration), while a second scenario considers the replacement of NPP units by coal-fired power plants with fluidised bed combustion. As shown in the following table, each of these options will achieve a different level of emissions, depending on the share of NP in the electricity generation mix:

Table 16.1. Average annual emissions [kt] in period 2008 – 2012

# of NPP units	CO_2	SO_2	NO_x	SP
Gas option				
6 × 440 MWe	6868	5.35	19.48	1.63
4 × 440 MWe	8869	5.54	27.24	1.69
2 × 440 MWe	10814	5.54	35.53	1.69
Coal option				
6 × 440 MWe	9208	11.17	18.44	3.08
4 × 440 MWe	13703	17.66	25.45	4.71
2 × 440 MWe	18644	25.30	33.07	6.61

Sensitivity analyses were performed on three indicators (incremental investment cost required to finalize two nuclear units, level of carbon tax, and lignite price escalation) to assess the competitiveness of the following candidates: combined cycle, fluidised bed combustion of domestic coal, and finishing two nuclear units at the Mochovce NPP, with combined cycle providing the base line competition to be met by other technologies. The following table summarises the conditions required for fluidised bed and nuclear plants to be competitive.

Thus, nuclear power could compete if its capital costs did not exceed the baseline of $1634 by more than $817/kWe. Or, nuclear power would be competitive with a carbon tax of more than $40/t$CO_2$.

This CRP also studied the impact of combined cycle IPPs on the electricity generation mix and on emission levels in the public electricity sector. During the final stage of the CRP, a methodology was developed for determining the reduction in CO_2 emissions attributable to IPPs operating outside the public utility framework. This is important for evaluating investment in IPPs as Joint Implementation (JI) and Clean Develop Mechanism (CDM) projects established under the Kyoto Protocol. Three options were analysed, representing JI and CDM projects with industrial CC and other types of IPPs, each having a different baseline developed by considering different expansion candidates in DECPAC. Option 1 represents the situation where combined cycle (CC) power plants are considered in the public electricity framework. Option 2 represents the scenario where CC and one fluidised bed combustion unit of 300 MWe are considered. Option 3 represents the scenario where a baseline is defined as 2 440 MWe nuclear units together with the expansion candidates from Option 2. The industrial CC penetration starts with 36 MWe capacity in 2002 and grows to 469 MWe in 2014.

Table 16.2. Comparison of nuclear power and fluidised bed combustion coal plants

	NPP Inv.Costs [US$/kWe]	Carbon tax [US$/t$CO_2$]	Escalation of lignite price
Combined cycle	baseline	baseline	baseline
Finalising NPP units	= < 817	= > 40	
Fluidized bed combustion			0%
Baseline values	1634	0	3.88%

Table 16.3. CO_2 emissions in three scenarios

Option	1	2	3
Fuel type	kt CO_2	kt CO_2	kt CO_2
Hard Coal	14	-3	113
Bituminous Coal	5	15	854
Natural Gas	23	23	65
Natural Gas in CC	963	973	381
Total	1004	1009	1413

A further analysis of the impact that nuclear energy had on the fuel mix and generation level in the Slovak Republic during the period 1980 to 1992, indicates that energy related CO_2 emissions would have been between 53 and 64 million tonnes higher in the absence of nuclear power. This study also determined that finishing construction of the two nuclear units at Mochovce NPP would create an additional CO_2 emissions offset that would permit the country to participate in international emissions trading. The amount of created ERU's, their abatement costs and financial income from emission trading for two market prices are given in the Table 16.4.

The ECOSENSE model was used to estimate the external costs of electricity generation associated with health impacts from SO_2 and NOx emissions. These values were then compared with SO_2 and NOx emission fees and charges applied in Slovakia. The results indicate that present emission charges are substantially lower than the external costs. Only in the case of fines assessed for exceeding existing pollution limits on flue gas concentration, the emission charges approach the level of (or sometimes exceed) the external costs.

Table 16.4. CO_2 abatement costs and income from emission trading

	Unit	Period 1997 – 2018	Period 1997 – 2012
CO_2	[mill. t CO_2]	42	24
Abatement cost	[USD/t CO_2]	3.1	11.4
Financial income from trading			
at 10 USD/t CO_2	mill. USD	420	240
at 40 USD/t CO_2	mill. USD	1680	960

16.3. Conclusions

The latest analyses, carried out in the framework of preparing the 3rd National Communication on Climate Change, indicate that Slovakia would meet the Kyoto Protocol commitments without any special effort. This could open the door for emission trading in the framework of the Kyoto flexible mechanisms. Although it seems possible for Slovakia to comply with its the Kyoto commitments even after retiring two existing nuclear units and suspending construction of two new ones, the reduction in nuclear generation will decrease the CO_2 emission offsets available for emissions trading. Conversely, finishing construction of two units at Mochovce represents an additional potential for emissions trading. In view of the allowance trading mechanism, one must take into account that financial income from trading would be available only after putting these units into operation and therefore this approach would not solve the current problem of lack of investment resources. If needed, we could theoretically create these financial resources for the time of construction under the JI mechanism, but for the nuclear technology is still not accepted in the list of available JI technologies.

The valuation of new IPPs as JI projects outside the traditional energy supply system is highly sensitive to estimates of the decrease in CO_2 emissions from grid electricity attributable to such a project. The method developed for this study uses a combination of DECPAC and MS EXCEL-based modules to solve this problem.

Finally, this research found the ECOSENSE model to be a useful tool for estimation of external costs of electricity generation system. Nevertheless, additional efforts are required to incorporate representative data for East European countries in the model.

17. SWITZERLAND

A STRATEGIC ELECTRIC SECTOR ASSESSMENT METHODOLOGY UNDER SUSTAINABILITY CONDITIONS (SESAMS)

Designing and implementing a sustainable energy sector is a key element in defining and creating a sustainable society. In the electricity industry, the question of strategic planning for sustainability seems to conflict with the shorter time horizons associated with market forces as deregulation replaces vertical integration. To address such questions, a project called SESAMS (Strategic Electric Sector Assessment Methodology under Sustainability) was established to develop electricity sector planning methods related to sustainability. This effort is part of the Alliance for Global Sustainability formed by the Massachusetts Institute of Technology (MIT), the Swiss Federal Institutes of Technology (ETHZ and EPFL), and the University of Tokyo (UT).

A technical contract was arranged under the IAEA's Co-ordinated Research Project (CRP) on comparative assessment of electricity generation options, so that the results of the SESAMS project could be shared under the CRP. This executive summary highlights the results of two Swiss case studies on stranded costs and environmental externality dispatch.

17.1. SESAMS 98 - Stranded Cost Issues

The issue of stranded costs was chosen for the SESAMS 98 study because of the significant amount of stranded assets involved, the relevance to the Swiss deregulation debate, and the question of how different methods of handling stranded costs might interact with other electric sector strategies and sustainability considerations. The choice of the stranded cost issue has expanded the analytic focus from domestic Swiss costs and emissions to include a study of how costs and generation are divided between different groups of generating companies within Switzerland.

The stranded cost issue that is usually addressed is "which generators qualify as stranded assets and how large are these stranded costs?" This question depends upon future generation and electricity prices that are uncertain, and produce different estimates of stranded costs. The present work has taken a somewhat different approach. Industry estimates of stranded costs were taken and then divided into three classes of generation assets, including hydro power plants, Swiss nuclear plants, and long term contracts or drawing rights on French nuclear plants. The question analysed was what the effect would be of including some, all or none of these asset classes for recovery as stranded costs. Based on the perceived probability of political acceptability, four options were chosen. These were: recovery of 1) no stranded assets, 2) hydro assets only, 3) hydro and nuclear assets, and 4) hydro, nuclear and drawing rights assets. Two subsidiary questions were also asked regarding the effect of the length of the stranded asset recovery period and the effect of fixed versus variable (per kW·h) recovery of stranded costs.

Because stranded cost recovery as considered here is a transfer payment that is gathered from a fee on all generation (or sales) and paid to those utilities with stranded assets, there is little or no impact on total national generation costs. Instead, the impact is upon the relative competitiveness of the different companies that own or do not own the stranded plants. Swiss utilities were aggregated into six groups (plus one for new plants), and these six groups divided the stranded assets according to their shared ownership. The impacts of the stranded cost policies were then studied to see which groups were the relative winners and losers.

17.1.1. Stranded Cost Results

The stranded cost results focus upon the relative generation costs for seven groups of Swiss utility companies. Five of the groups were for large utilities and smaller utilities affiliated with them, including ATEL, BKW, EOS, NOK and WATT. One group (OTHER) was for smaller, non-affiliated utilities, and the last group (NEW) was for new capacity built during the study period.

Stranded Cost Inclusion – All four stranded cost inclusion options were analysed. The stranded cost fee is born by all, but the stranded cost recovery is paid only to stranded asset owners. Different company groups own different amounts of each asset class, so with each cumulative inclusion of additional stranded assets the pattern of who wins and loses changes. Under the zero stranded assets option, the relative positions of the seven company groups are unchanged. When only stranded hydro costs are recovered, the three relatively greatest winners (in descending order) are EOS, NOK and the NEW group. The groups WATT and OTHER had mixed results depending upon other factors and options, and the losers were BKW and ATEL.

When Swiss nuclear stranded assets (Leibstadt) are added, this pattern shifts so that the winners in descending order are ATEL, WATT, EOS, NOK, NEW, OTHER, and BKW. Finally, when stranded contractual assets are included the spectrum of winners in descending order shifts to WATT, NOK, EOS, NEW, OTHER, ATEL and BKW. The real winners and losers at either end of the spectra are more clearly discerned than the are the results for the company groups in the middle, where patterns are more mixed and depend on other options.

Stranded Cost Recovery Period - As expected, a shorter recovery period increases the relative advantages and disadvantages to the different company groups during the period. The production cost results presented in the detailed report were averaged over the recovery period, so halving the period from ten to five years approximately doubles the impacts on which company groups are winners or losers.

Fixed vs. Variable Stranded Cost Recovery - The stranded cost results show that adding a revenue-neutral stranded cost recovery program does not cause significant changes in system dispatch or any significant impact on total system cost. Stranded costs may be paid on either a flat reimbursement basis or on a variable energy basis (per kW·h), depending upon whether there is any political reason to place added incentive on plant utilization (higher capacity factor).

Interaction with Other Strategy Options - Because the Swiss system is composed primarily of base load nuclear and energy-limited hydro capacity, it is assumed that any excess energy beyond domestic Swiss demand will be exported. For this reason the addition of a cost-neutral, stranded cost recovery program does not have any significant effect on the total societal cost of electricity. For these same reasons, the addition of stranded cost recovery also does not significantly affect the cost and CO_2 performance of the other options included in the scenario set for the different company groups relative to each other. This means that the addition of stranded cost recovery does not affect the choice of which other options are best for Switzerland. The one exception to this is in the unlikely case that the Leibstadt nuclear plant would be retired before the end of the stranded cost recovery period, coupled with the assumption that the remaining associated stranded costs would not be recovered, which conditions would result in a comparative disadvantage to those groups with ownership shares.

17.2. SESAMS 99 - Environmental Externality Issues

The issue of environmental externality costs, and how their addition or internalization would affect the economic dispatch of the Swiss system was chosen for the SESAMS 99 study because of its relevance to the Swiss energy debate, and in particular for its contrast with other forms of energy taxes then being proposed. The choice of the environmental “adder” or energy tax as an issue has expanded the analytic focus from domestic Swiss costs and emissions to include how costs, generation and emissions are shared between Switzerland and other countries which would presumably be the sources of imported power.

By imposing external environmental adders to system dispatch costs in the form of a 'virtual' tax, the question that was addressed was whether the increased generation cost incurred by the departure from the previous basis for economic dispatch is a fair price to pay for the reduction in environmental burdens. Whether the tax is real (collected) or virtual (a non-collected dispatch consideration) is less of a analytic issue than a political one, since on a societal basis such taxes are a zero-sum transfer payment that can be used to ameliorate the environmental damages to people or property, or alternately used to displace other tax revenues. Based upon estimated ranges (low to high) for the external costs of GHG and non-GHG burdens, a series of options were constructed with different combinations of zero, low and high dispatch adders for both GHG and non-GHG externalities on both domestic generation and foreign imports.

One focus of this analysis is the shift in generation patterns between different technologies that have different mixes of GHG and non-GHG externalities. These produce changes in costs and shifts in the location of environmental emissions. Because of the contrast between Switzerland's dominant hydro/nuclear mix and the fossil mix contained in imported power, the focus on generation mix translates to a trans-border question of how domestic Swiss regulations and foreign emissions should be balanced.

17.3. Environmental Externality Results

Externality Adders on Domestic Generation — The first major result of imposing environmental externalities on domestic generation is that the effect is primarily on price, and not on domestic CO_2 emissions. This is due to the fact that the primary effect of imposing externality adders on domestic generation is to increase dependence on power imports, which increases costs but results in much larger changes to foreign than to domestic CO_2 emissions. This is because current Swiss generation has effectively zero CO_2 content, and future gas generation would have low CO_2 content, while imports have a higher CO_2 content based on their fossil generation mix. The cost increase can be quite significant, but depends upon how the externalities interact with the other options present in each scenario. Increasing externality adders on domestic generation therefore increases the range of the average cost of service. Specifically, as the levels of external costs are increased individually and in combination, the lowest price for each domestic externality option remains low (generally between 12 and 13 rp/kW·h), but the upper limit of the price range increases (up to 17 rp/kW·h, for the highest). This is due to the fact that externality adders cause the system to depart from the previous least cost system dispatch. Even though the cost of the adders themselves is not included in the actual cost, the departure from an economic dispatch based only upon internal costs means that the average price of electricity must go up. The price increase reflects the theoretical internalisation of the external costs.

Externality Adders on Domestic and/or Foreign Generation — If environmental adders increase the dispatch price of only domestic generation resources, it is obvious that there will be a pressure to shift to increased foreign imports. Since non-greenhouse gas and greenhouse gas emissions can have regional or global effects, respectively, it is clear that imposing only domestic externality adders may have the effect of shifting and/or increasing emissions-related problems. This means that the pattern of how generation shifts occur based on externality adders is most clear when the possibility of foreign externalities are added to domestic externalities. For this reason an import externalities adder option was used that set adders on power imports at either zero or at Swiss levels.

The results show that the import externalities option has a major effect upon the cost to the Swiss consumer, increasing the maximum price from about 14.5 rp/kW·h to over 17 rp/kW·h in the worst case. As before with domestic externalities adders, there is relatively little effect on domestic CO_2 emissions, but major effects upon foreign and hence total CO_2 emissions. Adding externalities on imports can increase the average cost of electric service by 0.4 to 2.7 rp/kWh, with an average increase over all scenarios of 1.0 rp/kW·h (7.8%). It can have an impact on domestic CO_2 emissions that ranges from an increase of 0 to 25.6 million tonnes of CO_2, with an average increase of 1.82 million tonnes (12.4%) in domestic CO_2 emissions.

Increasing GHG adders on *both* domestic and imported generation gradually increases the use of Swiss-owned nuclear located in both Switzerland and France. When the adder is increased from zero to the low level for the base case scenario, the fluctuating Swiss nuclear generation level prior to 2012 levels out at its maximum level while French nuclear generation use increases, and when the GHG adder is increased to the higher level the French nuclear use increases yet again. This effect is only observed when GHG externalities are added to foreign imports, which contain significant CO_2 content.

When non-GHG externalities on domestic generation are high, the Swiss use of Swiss and French nuclear generation is minimized. However when Swiss level externalities are imposed upon imports, then this situation is reversed. Swiss and French generation for use in Switzerland is maximized, imports are minimized, and some more Swiss gas-fired capacity is used. This strong shift also occurs when both GHG and non-GHG externalities are high, but since it happens without the GHG externalities it is clear that the non-GHG adders cause the shift. This shift does not happen with the zero or low level non-GHG externalities, which illustrate how dispatch changes can 'flip-flop' when the relative position of two technologies are reversed in the dispatch order.

Life Cycle Burdens Associated with Externality Adders — Because imposing different levels and combinations of environmental externalities shifts generation between domestic and foreign sources, there are also correlated life cycle burdens associated with these technology mixes. When the combination of adders imposed shifts generation toward Swiss-owned nuclear resources, this reduces air emissions, expected fatalities and expected job-related injuries, while increasing uranium consumption, nuclear waste production, and expected evacuations and monetary losses due to accidents. When generation is shifted to foreign imports that are a weighted mix of fossil generation technologies, then the converse is true.

17.3.1. Multi-criteria Decision Analysis Results

The SESAMS 99 project included as part of its analysis an effort to implement a more formal multi-criteria decision aiding process to help demonstrate a structured method for stakeholders to rank their preferences. With the help of an academic stakeholder advisory group, the EPFL team developed a set of eleven quantitative and qualitative decision-making criteria important to them, including measures of environmental, economic and societal results and risk. The stakeholders weighted these criteria. Using some additional analysis of the normal SESAMS results, a reduced set of scenarios (that had already been judged as both relatively good performers and diverse) was then ranked. These rankings were then subjected to sensitivity analysis to see how robust the results were.

The results of this process were a set of rankings for each stakeholder that was quite consistent in selecting a best strategy that incorporated scheduled nuclear retirement, high levels of end-use efficiency, cogeneration, and renewable. Interestingly, the ranking consensus did not choose a strategy that appeared good (or dominant) based on the cost and CO_2 measures that were predominantly used in the rest of this report. This confirms that, at least for the academic advisory group that participated, other criteria were important enough to reorder their preferences.

17.3.2. Policy Recommendations

The purpose of the integrated SESAMS methodology is to inform stakeholders and to help them make their own decisions about power system development and whether it is sustainable, rather than for the analysis team to make its own recommendations. However, if public interest focuses on the primary measures of cost and emissions that this study has analyzed, then a coordinated mix of certain options seems reasonable. Based on results from three major scenario sets using increasingly large system boundaries, it appears that a balanced program of nuclear life extension and end-use efficiency programs can offer cost effective benefits, and the scale of these options are sizable enough to have significant impact.

Stranded cost policy is more difficult since there are clear winners and losers in the marketplace as shown by this report. It should be born in mind however that the relative winners and losers are not just the various companies. Stranded costs are collected from the public to be paid to utilities, so the public will pay for the transition if stranded costs are awarded. The fact that in Switzerland many smaller utilities are publicly owned merely complicates the matter, since the entire public will pay according to their electricity use, and a minority of the public will receive based on their utility ownership through the canton or community.

The SESAMS 99 results show that the level of GHG and non-GHG externality burden valuations imposed as dispatch adders on generation technologies can have a significant impact. Once such valuations are chosen, they should be evenly rather than selectively applied. This means that energy taxes should be based upon life cycle burdens that translate to impacts, and not just on flat energy production or whether a resource is renewable or not. The SESAMS 99 results show that the shift between domestic and imported generation that results from some combinations of dispatch adders can produce perverse environmental effects that reduce Swiss emissions but increase foreign, and thus global, emissions. The clear message here is that Swiss decision-makers should be aware of these shifts and take them into account in making new energy policies.

18. TURKEY

COMPARISON OF ECONOMIC AND ENVIRONMENTAL RESULTS OF SEVERAL SCENARIOS REGARDING MITIGATION OF ATMOPHERIC POLLUTIONS IN TURKEY

18.1. Summary

The power system of Turkey has developed very rapidly. Based on projections of industrial and economic growth along with a continued increase in population, electricity demand is expected to increase at a rate of roughly 7% per annum for the period 2001-2020. Results of a recent demand forecast study indicate that the demand for electrical energy was expected to reach 141 TW·h in year 2001, 300 TW·h in year 2010 and 565 TW·h by 2020. In order to cover the peak load and electrical energy demand safely and with a suitable reserve capacity, it will be necessary to extend the power system by commissioning approximately 80 GW of new capacity over the next 20 years. Therefore, comparative assessment of different electricity options particularly from an environmental viewpoint should be performed.

The objective of this study is to analyse alternative cases to determine a reference electricity generation expansion plan that would provide a reliable supply of electricity while mitigating atmospheric pollution in a cost effective manner. These analyses were performed with the DECADES Computer Tools.

Under the current study, initial activities focused on developing a Country Specific Database (CSDB) that characterizes all types of primary energy resources currently being used in Turkey or expected to be used for future electricity generation. Technical, economic and environmental data was also defined for technologies at each step of the various energy chains i.e. fuel extraction, fuel storage facilities, vehicles for fuel transport, and electricity generation technologies. Control technologies for reducing air pollution, transporting waste and disposing of waste were also included in the CSDB.

Energy chains were created for each existing and candidate power plant analyzed under the study, in order to assess the economic costs and environmental damages associated with each step from energy source to waste disposal. A feature for energy chain comparison in the DECADES Computer Tools permits the analysis of a user-specified mix of energy chains and pre-determined electricity demand. Six different cases were established to assess the environmental burdens associated with different technology mixes for meeting an annual electricity demand of 3500 MW. This value corresponds to the expected annual increase in electricity demand for Turkey. In each comparison, the full fuel chains of either one fuel type or a composition of several fuel types were considered.

The energy chain comparison indicated that the case where increasing electricity demand is met solely by construction of new lignite-fired power plants would result in the highest level of environmental burden. On the other hand a mix of gas and nuclear generation would give the lowest SOx and greenhouse gas (GHG) emissions. For full energy chains, direct emissions come from electricity generation were calculated as well as auxiliary emissions (e.g. those from electricity used to transport fuel to the power plant by conveyor belt). These calculations showed that electricity generation step (i.e., the power plant) accounts for 90% of GHG emissions associated with the lignite chain.

The DECADES Computer Tools were also used to conduct a system-level analysis of different expansion strategies to determine an environmentally sound least-cost expansion plan for the coming decades. Four case studies were analysed, the first one being the least cost generation expansion plan while the other three cases were alternatives (Table 19.1). In the second case, constraints were imposed on the number of projects that can be added to the system in each year. Additional renewable energy sources were taken into account as generating expansion alternatives in the third case. The fourth case analysed the impact of a GHG tax in Turkey. Although the country has not applied a GHG tax to the generation system, this study was done to assess the impact of three different levels for the value of GHG tax.

Table 18.1. Comparison of Cases by Additional Capacity Requirement, Total System Cost and the Associated Environmental Burdens

COMPARISON OF CASES

ADDITIONAL CAPACITY (MW)

	REFERENCE	IMPLEMENT. CONSTRAINTS	GREATER PENET. OF RENEWABLES	GHG TAX 1 (10 $/TON)	GHG TAX 2 (20 $/TON)	GHG TAX 3 (30 $/TON)
ADDITIONAL CAPACITY (MW)						
LIGNITE + HARD COAL	0	10452	0	0	0	0
IMPORTED COAL	0	10332	0	0	0	0
NATURAL GAS	65100	28700	63700	61600	61600	11200
FUEL OIL	0	3381	0	0	0	0
NUCLEAR	0	9000	0	2000	2000	53000
HYDRO	17343	17343	22038	22038	22038	22038
TOTAL	82443	79208	85738	85638	85638	86238
OBJECTIVE FUNCTION (Billion US $)	52.9	59.4	53.1	57.0	60.8	70.8
AIR EMISSIONS in 2020 (Million Tonnes)						
CO2	199	268.0	192.0	185.0	185.0	38.0
SOx	1.2	3.9	1.2	1.2	1.2	0.5

Taking into account the assumptions and data used in this study, the least cost generation expansion plan shows a successive market preference for addition of natural gas-fired and hydroelectric power plants for future generating system expansion in Turkey. In this case, 79% of the capacity additions come from natural gas-fired power plants, while the rest comes from hydroelectric projects.

The implementation constraint case takes into account a need for diversification of resources and of import sources. In this case, all domestic lignite and hard coal-fired plants as well as hydroelectric projects included in the so-called variable system, would have been added by the end of planning period (2020). In addition to these domestic resources, the model for this case also selects imported coal, fuel oil and nuclear-based power plants under specified constraints.

In the third case, natural gas-fired power plants and hydroelectric projects are again selected for future system expansion. In this case an additional 4695 MW of installed renewable (hydro) capacity is, replaces some 1400 MW (2 units) of natural gas fired power from the least cost solution. However, since domestic renewable energy resources are very limited both in terms of capacity (MW) and energy (GW·h), and since the electricity demand growth rate is very high, these additional renewable resources have little effect on the on the expansion plan.

In the fourth case, the impact of GHG tax values of $10, 20 and 30 US/ton were compared. For $10 and $20/ton taxes, the optimum mix was slightly different than in the least cost solution. Besides natural gas-fired power plants and hydroelectric projects, two nuclear plants would be added in the optimal solutions. If implementation constraints are applied for all candidate units, at the same time as a GHG tax, then nuclear power plants are included in the expansion plan at the earliest possible time (on-line in 2008 due to construction requirements). The $30/ton tax completely changed the results from the reference solution, and nuclear power plants become more preferable than gas-fired units. In this case, in the year 2020 the share of natural gas-fired power plants in the total installed capacity falls to 15% from 64% in the least cost case, while the share of nuclear power plants rises to 46% from zero.

18.2. Study Results

In terms of total expansion cost (objective function)*, the first case is the least cost, while the last case ($30 GHG tax) is the most costly expansion plan. The maximum CO_2 emissions (tons/year) result from the implementation constraint case where coal and fuel oil fired power plants as well as natural gas plants are added to the system. CO_2 emissions will be at the lowest level where a $30/ton GHG tax results in a large nuclear share in the system.

Taking into account the assumptions and data used in this study, natural gas-fired power plants are the most economically preferable expansion alternative. In 2020, depending on the selected case, natural gas consumption in the power sector will vary between 25 to 100 billion cubic meters per year. While Turkey currently imports natural gas for use in the power sector, the present gas contracts will not cover the additional supply needed for planned gas-fired units. For that reason, necessary steps should be taken now toward providing adequate gas supply in the future.

This comparative analysis of alternative expansion plans has also shown that the least cost solution is not the one with the lowest emissions. In fact, the expansion plan that will cause minimal environmental burdens has the highest capital costs. The investment requirements for these two expansion plans are calculated as $58.5 and $165.5 billion (1995 prices), respectively. This level of investment should be considered against the financial capabilities of the country; just as the results of such demand forecasts and optimization analyses should be carefully reviewed in order to assess their national economic and financial impact.

* Present worth value of the sum of: investment cost of all plants added by the program, plus the annual (fuel and non fuel) operating costs of the system, plus the cost of unserved energy, all discounted at 1995 using an annual discount rate of 8%.

Part III
LESSONS LEARNED

DECADES must be properly viewed as part of a continuing process during which the IAEA is constantly developing and making available analytical tools that reflect changing needs and interests in Member States. Each project contributes to this learning process, and DECADES has been no exception. DECADES was inaugurated when environmental concerns, particularly of a local and regional nature, were gradually receiving increased attention in the energy planning and policy making domains, but when there was also no systematic effort to compile and correlate technical, economic and environmental data pertaining to existing and planned energy facilities and fuels. Just when concerns about sustainable development and external costs were beginning to shape policy discussions, an adequate methodological approach for incorporating non-technical and non-cost considerations into planning processes was lacking.

In the context of its goal to overcome these deficiencies, the DECADES project met in remarkable fashion its three main objectives:

- Establishment and compilation of databases and information systems to support comparative assessment;
- Development of an integrated software package for comparative assessment of electricity generation options;
- Training and support for Member States in implementing comparative assessment case studies.

Data on emissions for full energy chains from resource extraction through plant construction and fuel delivery stages to electricity generation (cradle-to-grave approach) were successfully collected along with all the necessary economic and technology parameters. Once organized in structured data banks, the data were accessible through the then-relevant IAEA analysis tools such as DECPAC (which includes the electricity expansion model WASP). With DECPAC three types of hierarchically ordered analyses could be carried out: comparative assessment of specific energy technologies and investment projects, assessments of full energy chains associated with these specific choices, and comprehensive electricity system studies. The national comparative assessment studies conducted under this DECADES CRP, as well as other studies sponsored by the IAEA Technical Co-operation Programme (TC), involved capacity building in Member States through the training of experts and methodology transfer in the field of energy-environment planning. In summary, all objectives outlined at the outset of the DECADES project were successfully met, as further confirmed by the completion of this CRP.

Energy modelling is a learning-by-doing exercise and DECADES was no exception. Both the CRP and the many TC sponsored national DECADES studies provided experience from which model improvements could be made. Model adaptation and code modification were required to reflect the differences in regional or national energy systems, and to accommodate new technology applications not foreseen in the model design. Instant user feedback on desirable improvements in model design or missing system links and configurations reflecting specificities of national circumstances, made possible enhanced model capabilities, increased model robustness and improved model-user interfaces.

Each instance of user feedback represents a lesson learned. Indeed, many lessons were learned from the DECADES project, from the research carried out under this CRP, and from the recommendations of the DECADES users throughout the 1990s.

Key lessons include the following:

> *DECADES — The right tool at the right time*. There is strong confirmation of the sometimes embattled principles that (a) informed decision-making requires comparative assessment of all technical, economic, environmental, health and social impacts of different electricity generation options; (b) comparative assessment is an essential element in the elaboration and formulation of sustainable energy strategies in Member States; and (c) there is a real need for proven methodologies and access to reliable data for undertaking such analyses.
>
> *The DECADES Databases*. The wealth of detail in the DECADES data banks, geared to full energy chain analysis, proved to be both a virtue and a vice. The detail makes them particularly valuable for site-specific technology comparisons, or for investment planning and environmental assessments where the origin of fuel and its chemical composition, fuel delivery mode, generating technology and similar parameters are known through the foreseeable future. However, the benefit of this detail turns into an overwhelming burden for longer-term capacity expansion planning at the regional or national levels. For example, fossil fuels may originate from different plays of a single mine, the actual transport routes cannot be pinpointed a priori, the locations of renewables are not precisely specified or the enrichment process of nuclear fuels impossible to determine for years ahead. Under such circumstances, the analyst is usually forced to resort to averaging. With averaging the inherent advantages of the DECADES approach over other planning tools disappear.
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> Comparative assessment of different specific energy options requires access to reliable and up-to-date information on existing technologies and fuels within a country as well as on a menu of future technology and fuel options. In fact, the techno-economic performance characteristics of future technologies and fuels are all that really matter for decision-making. While existing technologies may serve as reference points, the capacities added during the first decades of the 21^{st} century would be distinctly different from those added during the 1990s. The CRP showed that although the RTDB and CSDBs contain much information related to existing generation technologies,many data could not be found or were out-dated, especially for the full chain analyses, as noted in the case studies by Croatia and Cuba. Regular maintenance and update of the DECADES databases would be required to avoid the risk of the databases becoming obsolete, particularly as technologies are changing, with the rate of change accelerating as technology diversity increases and plant scale becomes smaller. Appropriate levels of database maintenance would entail the continued expenditure of significant and dedicated resources, and even then many essential data related to future energy infrastructures remain non-existent, unavailable or highly uncertain.
>
> *The DECADES Software (DECPAC)*. The DECPAC analytical software is a composite of a number of Agency tools, adapted specifically for the goals of the DECADES project. DECPAC was essentially designed as a data retrieval and analysis software to access the DECADES databases. It useful features include: (a) quantification of

environmental burdens (e.g. tonnes of CO_2 emitted) at the power plant, fuel chain and system levels, (b) provision for incorporating pollution abatement technologies as add-on facilities to power plants and calculation of the cost-effectiveness of the chosen measures, and (c) identification of preferred decision alternatives.

However, DECPAC is built on the WASP methodology which is best suited for use by state-owned utilities operating under monopoly conditions. It is not very useful when determining investment strategies for electricity generating capacity in more commercially oriented electricity markets where profit maximization using existing infrastructure takes priority over long term investment planning.

WASP is notably deficient in its handling of cogeneration plants and power plants using multiple fuel input, as noted in the case study of Belarus. Furthermore, analysis of hydro facilities is not straightforward, as noted by the team from Macedonia.

Finally, DECADES became a complex package that outgrew its original mandate as a data bank for full life-cycle comparative assessments. While adding the original DECPAC as a tool for data access and for constructing full source-to-service energy chains was still consistent with the original mandate, the incorporation of other modelling tools such as WASP (although desirable) went beyond that mandate. Thus rather than serving as a data resource for other models, DECADES took on a life of its own as a modelling tool. The inclusion of system analysis tools meant importing the limitations of these models. When the latter underwent enhancements, the transfer into DECADES lagged behind and the ultimate implementation of these updates further increased its complexity.

Comparative Assessment. The experience from the CRP highlights the need to weigh and to reconcile a variety of concerns and priorities in determining preferred decision alternatives. This involves balancing economic, social and security of supply issues with alleviating local and global environmental impacts, all within a comprehensive framework for assessing alternatives. This approach continues to be the basis for the Planning and Economics Studies Section's 3E (energy, economics, environment) Analysis. All of the CRP case studies weighed at least the need to balance system expansion with environmental improvement.

DECADES was one of the first energy-environment analysis packages to include the IAEA’s DAM multi-criteria decision-making component as an integral feature of its analysis. Cuba, Indonesia, Philippines, and Switzerland all included a DAM analysis in their case studies. Romania and Slovakia also incorporated into their analyses the use of another decision aiding tool, indicators, to assess the impacts and the sustainable development potential of their various candidate options. Based in large part on this positive experience within the DECADES CRP, the IAEA has proceeded to incorporate the DAM module into its most recent environmental model, SIMPACTS.

The 1990s witnessed growing concerns about global climate change and sustainable development that began to shape policy discussions both at the national and international levels. The DECADES project was launched "just-in-time" to be an adequate tool for exploring most of the burning issues of the early 1990s. But by the end of the decade, energy markets as well as the sustainable energy development debate had become more sophisticated, and required additional analytical aspects (e.g. quantification of external costs of energy production and use, independent power production in competitive markets, endogenized technology learning, or emissions trading). Contemporary energy system planning or analysis requires moreover a good perception of future energy markets, technology potentials, socio-political constraints and a way to handle uncertainty.

The complexity entailed in energy system decision making and policy formulation has steadily increased. In essence DECADES was the response to this need at a time when it became evident that technical and least-cost energy supply considerations would no longer suffice as the dominant platform for energy investment planning. With growing population and increasing urbanization resulting in high-energy demand and population densities, it is no longer possible to ignore the health and environmental impacts of energy production and use. Comparative differences in emissions per unit of (ideally identical) energy service from different source-to-service pathways are therefore important as a first measure of the health and environmental impacts of energy production and use

But emissions by themselves do not provide a sufficient basis for informed decision making, especially when lower emission levels, because of abatement measures, result in higher costs and prices and vice versa. In fact, environmental policy has been evolving to focus not on emissions reduction per se but rather on the avoidance of undue (e.g. beyond the carrying capacity of ecosystems) damages to human health and the environment. The costs of emission mitigation must therefore be compared with the damage costs inflicted by the emissions on human health and the environment. While the former are relatively straightforward to calculate, this is not so for the quantification of damages (called externalities as long as these are not covered in production costs). The need for the development of adequate methodological tools that assist in the quantification of externalities became imminent. Such estimates are beyond the scope and capabilities of DECADES.

The 1990s were also characterized by fundamental changes in the way energy markets operate and how investment decisions come about. Governments and public sector institutions have begun to retreat from energy sector decision making and, more important, from being the dominant source of financing for the energy sector. Clearly, as private sector entities become increasingly involved in energy planning and decision-making, tools based on the single public agent assumption are no longer adequate.

Market liberalization and deregulation have immediate consequences for the way energy investment planning is exercised, as private sector institutions operate with shorter time horizons, different investment risk profiles and higher required returns on investments. Civil society increasingly makes its voice heard and public participation in the decision making process is becoming more and more commonplace. Add to this the waning of the paradigm of economies of scale that assumed larger energy installations would always beget conversion and economic efficiency. Quite the reverse, rapid technology advances in gas turbine, wind, biomass and fuel cell technologies have reduced efficient plant sizes and improved techno-economic performance. Smaller unit sizes and shorter implementation cycles have facilitated, to a certain extent, electricity and energy sector reform.

The role of governments now becomes that of creating level playing fields based on national sustainable energy development objectives and control/enforcement of regulatory compliance. Supply security concerns, of little importance throughout the 1990s, have recently resumed high priority and will remain a matter of government policy. Moreover, supply issues are now also addressed through demand side management and integrated resource planning. The concept of "Negawatts," for example, encapsulates changes at the level of energy end-use (e.g. efficiency improvements of appliances or leak-plugging) with the net effect of reducing additional generating capacities without compromising energy service availability and quality.

In summary, since its original design the DECADES tool has been confronted with two major changes: (1) the technological specificities of how a particular energy system is mirrored in a modelling context became increasingly complex (multi-input, multi-output systems, technology chain vs. single technology, energy storage, growing number of constraints or recursive feedbacks); and (2) the changed market and institutional realities expanded the required analytical boundaries and hence, more important, affected model design. The most drastic design modifications in modelling must occur when the very system under scrutiny undergoes metamorphosis itself. If metamorphosis extends beyond certain original design limits, evolutionary improvements of a particular modelling tool may no longer be feasible and newly designed tools need to be developed. This is what has happened in the case of DECADES.

Coinciding with the completion of the DECADES CRP, the IAEA convened several meetings soliciting input from the energy-environment modelling community and Member States as to their needs and expectations for the IAEA's analysis tools. The preceding paragraphs provide a generic synopsis of the input received during these meetings and from the CRP. Once this feedback was translated first into a wish list of desirable DECADES enhancements and then into mathematical modelling terms, it quickly became obvious that this would explode its design boundaries. Although technically feasible, an enhancement of the DECADES design to meet the new requirements and changed needs of Member States would have absorbed unwarranted resources. Moreover, there are practical limits to shoehorning new features into a structure that was not designed for them, not the least of which would be the dedicated staff resources needed for continuously updating data bases to complement the revised system tools. Rather, it was decided to launch the development of a new and more advanced set of analysis tools.

DECADES users and CRP participants have thus provided valuable input into the IAEA's on-going process of model development. Their recommendations for further research and development in the field of comparative assessment reflect in large part the changing methodological and policy needs of Member States. Many of these have already been accommodated in new and advanced tools developed by the Planning and Economic Studies Section.

By 2002, the IAEA had completed development of several analytical tools that remedy in more direct fashion the analytical gaps, which DECADES could not entirely satisfy. These new tools include:

- A new and advanced tool for electricity system expansion planning as well as overall energy system analysis (MESSAGE), which is better suited for addressing questions raised in restructured electricity and energy markets. It includes enhanced features for representing co-generation plants in the analysis of combined heat and power systems, assessing the potential for renewable technologies, and analysing the effect of environmental regulations. MESSAGE not only retains all the features for comparative assessments of different energy options found in DECADES but also includes end-use conversion technologies.

This makes it a true integrated assessment model that permits the analysis of both supply and demand options. Moreover, MESSAGE provides the analyst with information on generating costs and market prices, emission trading values and technology learning.

* Financial analysis software, called FINPLAN, used to assess the financial consequences of a power expansion programme based on certain "ratios" that financial institutions take into consideration when judging the soundness of an investment project or programme. FINPLAN can also be used to identify the selling price of electricity that would permit payback on investments. Forecasts developed with the model take into account price sensitivity to exchange rates, fluctuations in demand, and foreseeable inflation rates for both domestic and foreign currencies;

* A simplified methodology for estimating and valuing external costs associated with electricity generation, called SIMPACTS. Designed for use in developing countries that lack detailed data and cannot afford costly analyses, the programme can be used to estimate pollutant dispersion and transport, estimate the associated health and environmental impacts, and value these impacts or weigh them using a DAM analysis.

In sum, the IAEA’s current suite of tools for energy-economic-environmental analysis, incorporating and building on and superseding the experience of DECADES, provides a powerful system for the elaboration of sustainable energy strategies in the context of Agenda 21, market deregulation and privatization. Still, as in the case of DECADES, the new tools will eventually encounter new challenges. Technology and infrastructure continue to change as a result of ongoing innovation. Utilities may change their business models and increasingly become entities selling services rather than kWhs. Users may request additional features reflecting more detailed energy-economy-environment integration or interfaces. Policy makers and regulators may need methodologies for monitoring and verifying environmental or economic performance. In short, there is no "perfect" model that covers all eventualities. Hence, model maintenance and enhancement are a dynamic and ongoing process.

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